HOLLY CORP
Form 10-K
March 01, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

þ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the fiscal year ended December 31, 2006

OR

o **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the transition period from ____________________ to __________

Commission File Number 1-3876

HOLLY CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**75-1056913**
(State or other jurisdiction of incorporation or organization)	(I.R.S Employer Identification No.)
100 Crescent Court, Suite 1600, Dallas, Texas	**75201-6915**
(Address of principle executive offices)	(Zip Code)

Registrant s telephone number, including area code **(214) 871-3555**

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

Common Stock, $0.01 par value registered on the New York Stock Exchange.

Securities registered pursuant to 12(g) of the Act:

None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15 (d) of the Act.
Yes o No þ

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act). (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes o No þ

On June 30, 2006 the aggregate market value of the Common Stock, par value $.01 per share, held by non-affiliates of the registrant was approximately $2,007,000,000. (This is not to be deemed an admission that any person whose shares were not included in the computation of the amount set forth in the preceding sentence necessarily is an affiliate of the registrant.)

55,355,584 shares of Common Stock, par value $.01 per share, were outstanding on February 16, 2007.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s proxy statement for its annual meeting of stockholders to be held on May 24, 2007, which proxy statement will be filed with the Securities and Exchange Commission within 120 days after December 31, 2006, are incorporated by reference in Part III.

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PART I

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains certain forward-looking statements within the meaning of the federal securities laws. All statements, other than statements of historical fact included in this Form 10-K, including, but not limited to, those under Business and Properties in Items 1 and 2, Risk Factors in Item 1A, Legal Proceedings in Item 3 and Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 7, are forward-looking statements. These statements are based on management s belief and assumptions using currently available information and expectations as of the date hereof, are not guarantees of future performance and involve certain risks and uncertainties. Although we believe that the expectations reflected in these forward-looking statements are reasonable, we cannot assure you that our expectations will prove to be correct. Therefore, actual outcomes and results could materially differ from what is expressed, implied or forecast in these statements. Any differences could be caused by a number of factors including, but not limited to:

- risks and uncertainties with respect to the actions of actual or potential competitive suppliers of refined petroleum products in our markets;
- the demand for and supply of crude oil and refined products;
- the spread between market prices for refined products and market prices for crude oil;
- the possibility of constraints on the transportation of refined products;
- the possibility of inefficiencies, curtailments or shutdowns in refinery operations or pipelines;
- effects of governmental regulations and policies;
- the availability and cost of our financing;
- the effectiveness of our capital investments and marketing strategies;
- our efficiency in carrying out construction projects;
- our ability to acquire refined product operations on acceptable terms and to integrate any future acquired operations;
- the possibility of terrorist attacks and the consequences of any such attacks;
- general economic conditions; and
- other financial, operational and legal risks and uncertainties detailed from time to time in our Securities and Exchange Commission filings.

Cautionary statements identifying important factors that could cause actual results to differ materially from our expectations are set forth in this Form 10-K, including without limitation in conjunction with the forward-looking statements included in this Form 10-K that are referred to above. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements set forth in this Form 10-K under Risk Factors in Item 1A. All forward-looking statements included in this Form 10-K and all subsequent written or oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements. The forward-looking statements speak only as of the date made and, other than as required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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DEFINITIONS

Within this report, the following terms have these specific meanings:

Alkylation means the reaction of propylene or butylene (olefins) with isobutane to form an iso-paraffinic gasoline (inverse of cracking).

BPD means the number of barrels per day of crude oil or petroleum products.

BPSD means the number of barrels per stream day (barrels of capacity in a 24 hour period) of crude oil or petroleum products.

Catalytic reforming means a refinery process which uses a precious metal (such as platinum) based catalyst to convert low octane naphtha fractionated directly from crude oil to high octane gasoline blendstock and hydrogen. The hydrogen produced from the reforming process is used to desulfurize other refinery oils and is the main source of hydrogen for the refinery.

Cracking means the process of breaking down larger, heavier and more complex hydrocarbon molecules into simpler and lighter molecules.

Crude distillation means the process of distilling vapor from liquid crudes, usually by heating, and condensing slightly above atmospheric pressure the vapor back to liquid in order to purify, fractionate or form the desired products.

Ethanol means a high octane gasoline blend stock that is used to make various grades of gasoline.

FCC, or fluid catalytic cracking, means a refinery process that breaks down large complex hydrocarbon molecules into smaller more useful ones using a circulating bed of catalyst at relatively high temperatures.

Hydrocracker means a refinery unit that breaks down large complex hydrocarbon molecules into smaller more useful ones using a fixed bed of catalyst at high pressure and temperature with hydrogen.

Hydrodesulfurization means to remove sulfur and nitrogen compounds from oil or gas in the presence of hydrogen and a catalyst at relatively high temperatures.

Hydrogen plant means a refinery unit that converts natural gas and steam to high purity hydrogen, which is then used in the hydrodesulfurization, hydrocracking and isomerization processes.

HF alkylation, or hydrofluoric alkylation, means a refinery process which combines isobutane and C3/C4 olefins using HF acid as a catalyst to make high octane gasoline blend stock.

Isomerization means a refinery process for rearranging the structure of C5/C6 molecules without changing their size or chemical composition and is used to improve the octane of C5/C6 gasoline blendstocks.

LPG means liquid petroleum gases.

LSG, or low sulfur gasoline, means gasoline that contains less than 30 PPM of total sulfur.

MMBtu or one million British thermal units, means for each unit, the amount of heat required to raise one pound of water one degree Fahrenheit at one atmosphere pressure.

MTBE means methyl tertiary butyl ether, a high octane gasoline blend stock that is used to make various grades of gasoline.

Natural gasoline means a low octane gasoline blend stock that is purchased and used to blend with other high octane stocks produced to make various grades of gasoline.

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PPM means parts-per-million.

Refinery gross margin means the difference between average net sales price and average costs of products per barrel of produced refined products. This does not include the associated depreciation, depletion and amortization costs.

Reforming means the process of converting gasoline type molecules into aromatic, higher octane gasoline blend stocks while producing hydrogen in the process.

ROSE , or Solvent deasphalter / residuum oil supercritical extraction, means a refinery unit that uses a light hydrocarbon like propane or butane to extract non asphaltene heavy oils from asphalt or atmospheric reduced crude. These deasphalted oils are then further converted to gasoline and diesel in the FCC process. The remaining asphaltenes are either sold, blended to fuel oil or blended with other asphalt as a hardener.

Sour crude oil means crude oil containing quantities of sulfur greater than 0.4 percent by weight, while sweet crude oil means crude oil containing quantities of sulfur equal to or less than 0.4 percent by weight.

ULSD, or ultra low sulfur diesel, means diesel fuel that contains less than 15 PPM of total sulfur.

Vacuum distillation means the process of distilling vapor from liquid crudes, usually by heating, and condensing below atmospheric pressure the vapor back to liquid in order to purify, fractionate or form the desired products.

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INDEX TO DEFINED TERMS AND NAMES

The following other terms and names that appear in this form 10-K are defined on the following pages:

Terms used in the financial statements and footnotes are as defined therein.

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Items 1 and 2. Business and Properties

COMPANY OVERVIEW

References herein to Holly Corporation include Holly Corporation and its consolidated subsidiaries. In accordance with the Securities and Exchange Commission s (SEC) Plain English guidelines, this Annual Report on Form 10-K has been written in the first person. In this document, the words we , our , ours and us refer only to Holly Corporation and its consolidated subsidiaries or to Holly Corporation or an individual subsidiary and not to any other person.

We are principally an independent petroleum refiner which produces high value light products such as gasoline, diesel fuel and jet fuel. We were incorporated in Delaware in 1947 and maintain our principal corporate offices at 100 Crescent Court, Suite 1600, Dallas, Texas 75201-6915. Our telephone number is 214-871-3555 and our internet website address is www.hollycorp.com. The information contained on our website does not constitute part of this Annual Report on Form 10-K. A copy of this Annual Report on Form 10-K will be provided without charge upon written request to the Vice President, Investor Relations at the above address. A direct link to our filings at the SEC web site is available on our website on the Investors page. Also available on our website are copies of our Corporate Governance Guidelines, Audit Committee Charter, Compensation Committee Charter, Nominating / Corporate Governance Committee Charter and Code of Business Conduct and Ethics, all of which will be provided without charge upon written request to the Vice President, Investor Relations at the above address. Our Code of Business Conduct and Ethics applies to all of our officers, employees and directors, including our principal executive officer, principal financial officer and principal accounting officer. On April 26, 2004, our stock began trading on the New York Stock Exchange under the trading symbol HOC . Our stock formerly traded on the American Stock Exchange.

In July 2004, we completed the initial public offering of limited partnership interests in Holly Energy Partners, L.P. (HEP), a Delaware limited partnership that also trades on the New York Stock Exchange under the trading symbol HEP . HEP was formed to acquire, own and operate substantially all of the refined product pipeline and terminalling assets that support our refining and marketing operations in west Texas, New Mexico, Utah and Arizona and a 70% interest in Rio Grande Pipeline Company (Rio Grande). We initially consolidated the results of HEP and showed the interest we did not own as a minority interest in ownership and earnings. On July 8, 2005, we closed on a transaction for HEP to acquire our two 65-mile parallel intermediate feedstock pipelines which connect our Lovington and Artesia, New Mexico facilities, which reduced our ownership interest in HEP to 45.0%. Under the provision of the Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 46 (revised), Consolidation of Variable Interest Entities, we deconsolidated HEP effective July 1, 2005. The deconsolidation has been presented from July 1, 2005 forward, and our share of the earnings of HEP from July 1, 2005 is reported using the equity method of accounting.

As of December 31, 2006, we:

- owned and operated two refineries consisting of a petroleum refinery in Artesia, New Mexico that is operated in conjunction with crude oil distillation and vacuum distillation and other facilities situated 65 miles away in Lovington, New Mexico (collectively known as the Navajo Refinery), and a refinery in Woods Cross, Utah (Woods Cross Refinery);

- owned approximately 800 miles of crude oil pipelines located principally in west Texas and New Mexico;

- owned 100% of NK Asphalt Partners, which manufactures and markets asphalt products from various terminals in Arizona and New Mexico and does business under the name of Holly Asphalt Company; and

- owned a 45% interest in HEP (which includes our 2% general partnership interest), which has logistics assets including approximately 1,700 miles of petroleum product pipelines located in Texas, New Mexico and Oklahoma (including 340 miles of leased pipeline); eleven refined product terminals; two refinery truck rack facilities; a refined products tank farm facility; and a 70% interest in Rio Grande.

Navajo Refining Company, L.P., one of our wholly-owned subsidiaries, owns the Navajo Refinery. The Navajo Refinery has a crude capacity of 83,000 BPSD of sour and sweet crude oils, can process up to approximately 90% sour crude oils, and serves markets in the southwestern United States and northern Mexico. In June 2003, we acquired the Woods Cross refining facility from ConocoPhillips. The Woods Cross Refinery, located just north of Salt Lake City, has a crude capacity of 26,000 BPSD and is operated by Holly Refining & Marketing Company

Woods Cross, one of our wholly-owned subsidiaries. This facility is a high conversion refinery that processes regional sweet and Canadian sour crude oils. In conjunction with the refining operations, we own approximately 800 miles of crude oil pipelines that serve primarily as the supply network for our New Mexico refinery operations.

On March 31, 2006 we sold our petroleum refinery in Great Falls, Montana (the Montana Refinery) to a subsidiary of Connacher Oil and Gas Limited (Connacher). The net cash proceeds we received on the sale of the Montana Refinery amounted to $48.9 million, net of transaction fees and expenses. Additionally we received 1,000,000 shares of Connacher common stock valued at approximately $4.3 million at March 31, 2006. Accordingly, the results of operations of the Montana Refinery and a gain of $14.0 million, net of income taxes of $8.3 million, are shown in discontinued operations.

Our operations are currently organized into one business division, Refining. The Refining business division includes the Navajo Refinery, Woods Cross Refinery and Holly Asphalt Company. Prior to our deconsolidation of HEP on July 1, 2005 our operations were organized into two business divisions, which were Refining and HEP. Our operations that are not included in either the Refining or HEP (prior to its deconsolidation) business divisions include the operations of Holly Corporation, the parent company, a small-scale oil and gas exploration and production program, and prior to the deconsolidation of HEP, the elimination of the revenue and costs associated with HEP s pipeline transportation services for us as well as the recognition of the minority interests income of HEP.

REFINERY OPERATIONS

Our refinery operations include the Navajo Refinery and the Woods Cross Refinery. The following table sets forth information, including performance measures about our refinery operations that are not calculations based upon U.S. generally accepted accounting principles (GAAP). The cost of products and refinery gross margin do not include the effect of depreciation, depletion and amortization. Reconciliations to amounts reported under GAAP are provided under Reconciliations to Amounts under Generally Accepted Accounting Principles following Item 7A of Part II of this Form 10-K. Information regarding our individual refineries is provided later under this section of Refinery Operations.

	Years Ended December 31,		
	2006	**2005**	**2004**
Consolidated (8)			
Crude charge (BPD) (1)	96,570	95,950	94,680
Refinery production (BPD) (2)	105,730	106,040	103,060
Sales of produced refined products (BPD)	105,090	106,500	102,400
Sales of refined products (BPD) (3)	119,870	117,110	110,570
Refinery utilization (4)	92.4%	95.0%	94.7%
Average per produced barrel (5)			
Net sales	$ 80.21	$ 69.12	$ 51.40
Cost of products (6)	64.43	56.50	42.20
Refinery gross margin	15.78	12.62	9.20
Refinery operating expenses (7)	4.83	4.11	3.37
Net operating margin	$ 10.95	$ 8.51	$ 5.83
Feedstocks:			
Sour crude oil	61%	67%	65%
Sweet crude oil	28%	21%	24%
Other feedstocks and blends	11%	12%	11%

Total	100%	100%	100%

(1) Crude charge represents the barrels per day of crude oil processed at the crude units at our refineries.

(2) Refinery production represents the barrels per day of refined products yielded from processing crude and other refinery feedstocks through the crude units and other conversion units at our refineries.

(3) Includes refined products purchased for resale.

(4) Represents crude charge divided by total crude capacity (BPSD). Our crude capacity was increased from 101,000 BPSD to 109,000 BPSD in mid-year 2006.

(5) Represents average per barrel amount for produced refined products sold, which is a non-GAAP measure. Reconciliations to amounts reported under GAAP are located under Reconciliations to Amounts Reported Under Generally Accepted Accounting Principles following Item 7A of Part II of this Form 10-K.

(6) Subsequent to the formation of HEP, transportation costs billed by HEP are included in cost of products.

(7) Represents operating expenses of our refineries, exclusive of depreciation, depletion and amortization, and excludes refining segment expenses of product pipelines and terminals.

(8) The Montana Refinery was sold on March 31, 2006. Amounts reported are for the Navajo and Woods Cross Refineries.

The petroleum refining business is highly competitive. Among our competitors are some of the world s largest integrated petroleum companies, which have their own crude oil supplies and distribution and marketing systems. We also compete with other independent refiners. Competition in a particular geographic area is affected primarily by the amount of refined products produced by refineries located in that area and by the availability of refined products and the cost of transportation to that area from refineries located outside the area. Projects have been explored from time to time by refiners and other entities which projects, if completed, could result in further increases in the supply of products to some or all of our markets. In recent years, there have been several refining and marketing consolidations or acquisitions between competitors in our geographic markets. These transactions could increase future competitive pressures on us.

Set forth below is information regarding our principal products.

	Years Ended December 31,		
	2006	**2005**	**2004**
Consolidated			
Sales of produced refined products:			
Gasolines	61%	59%	59%
Diesel fuels	28%	27%	27%
Jet fuels	3%	4%	5%
Asphalt	2%	4%	5%
LPG and other	6%	6%	4%
Total	100%	100%	100%

We have several significant customers, none of which accounts for more than 10% of our business. Our principal customers for gasoline include other refiners, convenience store chains, independent marketers, an affiliate of Petróleos Mexicanos (PEMEX), the government-owned energy company of Mexico, and retailers. Diesel fuel is sold to other refiners, truck stop chains, wholesalers and railroads. Jet fuel is sold primarily for military use. Asphalt is sold to governmental entities or contractors. LPG s are sold to LPG wholesalers and LPG retailers and carbon black oil is sold for further processing or blended into fuel oil. Loss of, or reduction in amounts purchased by, our major customers that purchase for their retail operations could have an adverse effect on us to the extent that, because of market limitations or transportation constraints, we are not able to correspondingly increase sales to other purchasers.

In order to maintain or increase production levels at our refineries, we must continually enter into contracts for new crude oil supplies. The primary factors affecting our ability to contract for new crude oil supplies are our ability to connect new supplies of crude oil to our gathering systems or to our other crude oil receiving lines, our success in contracting for and receiving existing crude oil supplies that are currently being purchased by other refineries and the level of drilling activity near our gathering systems or our other crude oil receiving lines.

Navajo Refinery

Facilities

The Navajo Refinery has a crude oil capacity of 83,000 BPSD and has the ability to process sour crude oils into high value light products (such as gasoline, diesel fuel and jet fuel). The Navajo Refinery converts approximately 92% of its raw materials throughput into high value light products. For 2006, gasoline, diesel fuel and jet fuel (excluding volumes purchased for resale) represented 60%, 28% and 4%, respectively, of the Navajo Refinery s sales volumes.

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The following table sets forth information about the Navajo Refinery operations, including non-GAAP performance measures. The cost of products and refinery gross margin do not include the effect of depreciation, depletion and amortization. Reconciliations to amounts reported under GAAP are provided under Reconciliations to Amounts Reported Under Generally Accepted Accounting Principles following Item 7A of Part II of this Form 10-K.

	Years Ended December 31,		
	2006	**2005**	**2004**
Navajo Refinery			
Crude Charge (BPD) (1)	72,930	71,850	71,060
Refinery production (BPD) (2)	80,540	80,190	79,330
Sales of produced refined products (BPD)	79,940	80,110	78,880
Sales of refined products (BPD) (3)	93,660	89,400	86,410
Refinery utilization (4)	92.9%	95.8%	94.7%
Average per produced barrel (5)			
Net sales	$ 79.62	$ 69.11	$ 51.42
Cost of products (6)	64.25	55.50	41.26
Refinery gross margin	15.37	13.61	10.16
Refinery operating expenses (7)	4.74	3.94	3.20
Net operating margin	$ 10.63	$ 9.67	$ 6.96
Feedstocks:			
Sour crude oil	80%	85%	83%
Sweet crude oil	8%	2%	5%
Other feedstocks and blends	12%	13%	12%
Total	100%	100%	100%

(1) Crude charge represents the barrels per day of crude oil processed at the refinery.

(2) Refinery production represents the barrels per day of refined products yielded from processing crude and other refinery

feedstocks through the crude units and other conversion units at the refinery.

(3) Includes refined products purchased for resale.

(4) Represents crude charge divided by total crude capacity (BPSD). The crude capacity was increased from 75,000 BPSD to 83,000 BPSD in mid-year 2006.

(5) Represents average per barrel amount for produced refined products sold, which is a non-GAAP measure. Reconciliations to amounts reported under GAAP are located under Reconciliations to Amounts Reported Under Generally Accepted Accounting Principles following Item 7A of Part II of this Form 10-K.

(6) Subsequent to the formation of

HEP, transportation costs billed by HEP are included in cost of products.

(7) Represents operating expenses of the refinery, exclusive of depreciation, depletion and amortization, and excludes refining segment expenses of product pipelines and terminals.

Navajo Refining s Artesia, New Mexico facility is located on a 561 acre site and is a fully integrated refinery with crude distillation, vacuum distillation, FCC, ROSE (solvent deasphalter), HF alkylation, catalytic reforming, hydrodesulfurization, isomerization, sulfur recovery and product blending units. Other supporting infrastructure includes approximately 1.8 million barrels of feedstock and product tankage at the site, maintenance shops, warehouses and office buildings. The operating units at the Artesia facility include newly constructed units, older units that have been relocated from other facilities and upgraded and re-erected in Artesia, and units that have been operating as part of the Artesia facility (with periodic major maintenance) for many years, in some very limited cases since before 1970. The Artesia facility is operated in conjunction with an integrated refining facility located in Lovington, New Mexico, approximately 65 miles east of Artesia. The principal equipment at the Lovington facility consists of a crude distillation and associated vacuum distillation units which were originally constructed after 1970. The facility also has an additional 1.1 million barrels of feedstock and product tankage. The Lovington facility processes crude oil into intermediate products, which are transported to Artesia by means of two intermediate pipelines owned by HEP and which are then upgraded into finished products at the Artesia facility. The combined crude oil capacity of the two facilities is 83,000 BPSD and typically processes or blends an additional 10,000 BPSD of natural gasoline, butane, gas oil and naphtha.

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We have approximately 800 miles of crude gathering pipelines transporting crude oil to the Artesia and Lovington facilities from various points in southeastern New Mexico and west Texas, 66 crude oil trucks and 67 trailers in addition to over 600,000 barrels of related tankage.
We distribute refined products from the Navajo Refinery to markets in Arizona, New Mexico and west Texas primarily through two of HEP s owned pipelines that extend from Artesia, New Mexico to El Paso, Texas. In addition, we use a pipeline leased by HEP to transport petroleum products to markets in central and northwest New Mexico.
We have refined product storage through our pipelines and terminals agreement with HEP at terminals in El Paso, Texas; Tucson, Arizona; and Albuquerque, Artesia, Moriarty and Bloomfield, New Mexico.
In 2000, we formed a joint venture, NK Asphalt Partners, with a subsidiary of Koch Materials Company (Koch) to manufacture and market asphalt and asphalt products in Arizona and New Mexico under the name Koch Asphalt Solutions Southwest. We contributed our asphalt terminal and asphalt blending and modification assets in Arizona to NK Asphalt Partners and Koch contributed its New Mexico and Arizona asphalt manufacturing and marketing assets to NK Asphalt Partners. On January 1, 2002, we sold a 1% equity interest in NK Asphalt Partners to Koch, thereby reducing our equity interest from 50% to 49%. In February 2005, we purchased the 51% interest owned by Koch in NK Asphalt Partners for $16.9 million plus working capital of approximately $5.0 million. This purchase increased our ownership in NK Asphalt Partners from 49% to 100%. Following the purchase of the 51% interest from Koch, NK Asphalt Partners does business under the name Holly Asphalt Company.

Markets and Competition

The Navajo Refinery primarily serves the growing southwestern United States market, including El Paso, Texas; Albuquerque, Moriarty and Bloomfield, New Mexico; Phoenix and Tucson, Arizona; and the northern Mexico market. Our products are shipped through HEP s pipelines from Artesia, New Mexico to El Paso, Texas and from El Paso to Albuquerque and to Mexico via products pipeline systems owned by Plains All American Pipeline, L.P. (Plains) and from El Paso to Tucson and Phoenix via a products pipeline system owned by Kinder Morgan s SFPP, L.P. (SFPP). In addition, the Navajo Refinery transports petroleum products to markets in northwest New Mexico and to Moriarty, New Mexico, near Albuquerque, via HEP s leased pipeline running from Chaves County to San Juan County, New Mexico.

El Paso Market

The El Paso market for refined products is currently supplied by a number of refiners and pipelines. Refiners include Navajo, ConocoPhillips, Valero, Alon and Western. Pipelines serving this market include Longhorn, Magellan, and HEP pipelines. We currently supply approximately 11,000 BPD to the El Paso market, which accounts for approximately 18% of the refined products consumed in that market.

Arizona Market

The Arizona market for refined products is currently supplied by a number of refiners via pipelines and trucks. Refiners include companies located in west Texas, eastern New Mexico, northern New Mexico, the gulf coast and west coast. We currently supply approximately 47,000 BPD of refined products into the Arizona market, comprised primarily of Phoenix and Tucson, which accounts for approximately 16% of the refined products consumed in that market.

New Mexico Markets

The Artesia, Albuquerque, Moriarty and Bloomfield markets are supplied by a number of refiners via pipelines and trucks. Refiners include Navajo, Valero, Western, Giant, Alon and ConocoPhillips. We currently supply approximately 21,000 BPD of refined products to the New Mexico market, which accounts for approximately 20% of the refined products consumed in that market.
The common carrier pipelines we use to serve the Arizona and New Mexico markets are currently operated at or near capacity and are subject to proration. As a result, the volumes of refined products that we and other shippers have been able to deliver to these markets have been limited. In 2006, SFPP completed an expansion of its pipeline from El Paso to the Arizona market. Additionally, SFPP has announced a further planned expansion of the capacity of this pipeline from El Paso to the Arizona market, with an expected completion date of late 2007. We expect to maintain our market share of the 2007 SFPP expansion and ship additional volume to Arizona when additional

capacity is available. However, we cannot presently predict the ultimate effects on us of SFPP s proposed further pipeline expansion.

The common carrier pipeline we use to serve the Albuquerque market out of El Paso currently operates at or near capacity with resulting limitations on the amount of refined products that we and other shippers can deliver. In addition, HEP leases from Enterprise Products Partners, L.P. a pipeline between White Lakes, New Mexico and the Albuquerque vicinity and Bloomfield, New Mexico (the Leased Pipeline). The lease agreement currently runs through 2017, and HEP has options to renew for two ten-year periods. HEP owns and operates a 12-inch pipeline from the Navajo Refinery to the Leased Pipeline as well as terminalling facilities in Bloomfield, New Mexico, which is located in the northwest corner of New Mexico, and in Moriarty, which is 40 miles east of Albuquerque. These facilities permit us to provide a total of up to 45,000 BPD of light products to the growing Albuquerque and Santa Fe, New Mexico areas. If needed, additional pump stations could further increase the Leased Pipeline s capabilities.

The Longhorn Pipeline (Longhorn) was recently purchased by Flying J Inc. (Flying J) and is transporting refined products from gulf coast refineries to El Paso. This pipeline is approximately 700 miles long and runs from the Houston area to El Paso, utilizing a direct route. The previous owner, Longhorn Partners Pipeline, L.P., had announced that it would use the pipeline initially to transport approximately 72,000 BPD of refined products from the gulf coast to El Paso and markets served from El Paso, with an ultimate maximum capacity of 225,000 BPD. Since inception of Longhorn operations in late 2005, it is our understanding that there have been some shipments (substantially under the 72,000 BPD rate) of refined products. Since the purchase by Flying J, volumes shipped on Longhorn have been increasing. We understand Flying J is expanding the truck rack at its El Paso terminal to increase truck loading capacity and has a large fleet of trucks serving markets as far away as Arizona. Flying J has significantly increased the volume of gulf coast refined products shipped into El Paso and is actively exploring options to ship additional product on the SFPP system into Arizona, the Plains system into New Mexico, and into Mexico.

An additional factor that could affect some of our markets is excess pipeline capacity from the west coast into our Arizona markets. If refined products become available on the west coast in excess of demand in that market, additional products could be shipped into our Arizona markets with resulting possible downward pressure on refined product prices in these markets.

Crude Oil and Feedstock Supplies

The Navajo Refinery is situated near the Permian Basin in an area which historically has had abundant supplies of crude oil available both for regional users, such as us, and for export to other areas. We purchase crude oil from producers in nearby southeastern New Mexico and west Texas and from major oil companies. Crude oil is gathered both through our pipelines and tank trucks and through third party crude oil pipeline systems. In March 2003, we sold our Iatan crude oil gathering system located in west Texas to Plains for a purchase price of $24.0 million in cash. In connection with the transaction, we have entered into a six and a half year agreement with Plains that commits us to transport on that gathering system any crude oil we purchase in the relevant area of the Iatan system at an agreed upon tariff. Crude oil acquired in locations distant from the refinery is exchanged for crude oil that is transportable to the refinery.

We also purchase isobutane, natural gasoline, and other feedstocks to supply the Navajo Refinery. In 2006, approximately 4,700 BPD of isobutane and 3,500 BPD of natural gasoline used in the Navajo Refinery s operations were purchased from other oil companies in the region, as well as, volumes purchased from the mid-continent area and delivered to our region on an Enterprise common carrier pipeline. Ultimately all volumes of these products are shipped to the Artesia refining facilities on HEP s two parallel 65-mile pipelines running from Lovington to Artesia. From time to time, we also purchase gas oil and naphtha from other oil companies for use as feedstock.

Principal Products and Customers

Set forth below is information regarding the principal products produced at the Navajo Refinery:

	Years Ended December 31,		
	2006	2005	2004
Navajo Refinery			
Sales of produced refined products:			
Gasolines	60%	59%	59%
Diesel fuels	28%	27%	26%
Jet fuels	4%	4%	5%
Asphalt	3%	6%	6%
LPG and other	5%	4%	4%
Total	100%	100%	100%

Light products are shipped by product pipelines or are made available at various points by exchanges with others. Light products are also made available to customers through truck loading facilities at the refinery and at terminals. Our principal customers for gasoline include other refiners, convenience store chains, independent marketers, an affiliate of PEMEX and retailers. Our gasoline produced at the Navajo Refinery is marketed in the southwestern United States, including the metropolitan areas of El Paso, Phoenix, Albuquerque, Bloomfield, and Tucson, and in portions of northern Mexico. The composition of gasoline differs, because of local regulatory requirements, depending on the area in which gasoline is to be sold. Diesel fuel is sold to other refiners, truck stop chains, wholesalers, and railroads. Jet fuel is sold primarily for military use. All asphalt produced at the Navajo Refinery and third-party purchased asphalt is marketed through Holly Asphalt Company to governmental entities or contractors. LPG s are sold to LPG wholesalers and LPG retailers and carbon black oil is sold for further processing.

Military jet fuel is sold to the Defense Energy Support Center, a part of the United States Department of Defense (the DESC), under a series of one-year contracts that can vary significantly from year to year. We sold approximately 3,100 BPD of jet fuel to the DESC in 2006. We have had a military jet fuel supply contract with the United States Government for each of the last 37 years. Our size in terms of employees and refining capacity allows us to bid for military jet fuel sales contracts under a small business set-aside program. In September 2006, DESC awarded us contracts for sales of military jet fuel for the period October 1, 2006 through September 30, 2007. Our total contract award, which is subject to adjustment based on actual needs of the DESC for military jet fuel, was approximately 52 million gallons as compared to the total award for the 2005-2006 contract year of approximately 79 million gallons. The loss of our military jet fuel contract with the United States Government could have an adverse effect on our results of operations if alternate commercial jet fuel or additional diesel fuel sales could not be secured.

Capital Improvement Projects

We have invested significant amounts in capital expenditures in recent years to expand and enhance the Navajo Refinery and expand our supply and distribution network.

In December 2005, we finished the installation of a refurbished 4,500 BPSD ROSE asphalt unit at the Navajo Refinery at a total cost of $17.1 million. This unit allows us to upgrade asphalt to higher valued gasoline and diesel.

In 2006 we completed our ULSD project and an expansion of the crude capacity at the Navajo Refinery. These projects included the expansion and conversion of the distillate hydrotreater to gas oil service, the conversion of the gas oil hydrotreater to ULSD service, the expansion of the continuous catalytic reformer, the expansion and conversion of the kerosene hydrotreater to naphtha service, the installation of additional sulfur recovery capacity, and the installation of a 10 million standard cubic feet (mmscf) per day hydrogen plant. The completion of these projects has allowed us to produce all of our diesel fuel as ULSD and has expanded our crude oil processing capabilities from 75,000 BPSD to 83,000 BPSD. The total cost of these projects was approximately $75.0 million, which was approved in the prior year s capital budget. We plan to further increase crude capacity to 85,000 BPSD by the end of 2007 by relocating some heat exchangers and replacing some pumps in the Artesia crude unit at an estimated cost of $1.0 million.

Our Board of Directors approved a capital budget for 2007 of $24.7 million for refining improvement projects for the Navajo Refinery, not including the capital projects approved in prior years or our expansion and feedstock flexibility projects described below.

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As announced in December 2006 we will be installing a new 15,000 BPD hydrocracker and a new 28 mmscf hydrogen plant at a budgeted cost of approximately $125.0 million. The addition of these units is expected to increase liquid volume recovery, increase the refinery s capacity to process outside feedstocks, and increase yields of high valued products, as well as enabling the refinery to meet new low sulfur gasoline specifications required by the Environmental Protection Agency (EPA). The hydrocracker and hydrogen plant projects will provide improved heavy crude oil processing flexibility.

As announced in February 2007, we will be revamping an existing crude unit which will increase crude capacity at the Navajo Refinery to approximately 100,000 BPD. Additionally, our Board of Directors has approved a revamp of its second crude unit and a new solvent de-asphalter unit. The newly approved components, combined with the above described components approved in December, bring the total budgeted amount for this expansion and heavy crude oil processing project to $225.0 million. It is currently anticipated that the expansion portion of the overall project consisting of the initial crude unit revamp, the new hydrocracker and the new hydrogen plant will be completed and operational by the fourth quarter of 2008. The completion of the heavy crude oil processing portion of the overall project, including the second crude unit revamp and the installation of the new solvent de-asphalter, will be targeted to coincide with the development of future pipeline access to the Navajo Refinery for heavy Canadian crude oil and other foreign heavy crude oils transported from the Cushing, Oklahoma area. We plan to explore with HEP the most economical manner to obtain this needed pipeline access.

Also at the Navajo Refinery, a project to install an additional 100 ton per day sulfur recovery unit included in the 2006 capital budget is currently underway at an estimated cost of $26.0 million. Approximately $2.0 million was spent on this project in 2006. This new sulfur recovery unit will permit our Navajo Refinery to process 100% sour crude and is planned for start-up in the third quarter of 2008. It is anticipated that the projects that will be completed by the fourth quarter of 2008 will also enable the Navajo Refinery, without significant additional investment, to comply with LSG specifications required by the end of 2010.

Woods Cross Refinery

On June 1, 2003 we acquired the Woods Cross Refinery, located near Salt Lake City, Utah, and related assets, from ConocoPhillips. The purchase also included a refined products terminal in Spokane, Washington, a 50% ownership interest in refined products terminals in Boise and Burley, Idaho, 25 retail service stations located in Utah and Wyoming, and a 10-year exclusive license to market fuels under the Phillips 66 brand in the states of Utah, Wyoming, Idaho and Montana. The total cash purchase price, including inventory and related expenses and liabilities assumed was $58.3 million. In accounting for the purchase, we recorded inventory of $35.5 million, property, plant and equipment of $25.6 million, intangible assets of $1.6 million and recorded a $4.4 million liability, principally for pension obligations. In August 2003, we sold the 25 retail service stations for $7.0 million, less our prorated share of property taxes and certain transaction expenses, plus $1.8 million for inventories, resulting in net cash proceeds of $8.5 million. We continue to supply the retail stations with fuel from our Woods Cross Refinery under a long-term supply agreement.

Facilities

The Woods Cross Refinery is being operated by Holly Refining & Marketing Company Woods Cross, one of our wholly owned subsidiaries. Beginning in January 2005 the crude oil capacity of the refinery was increased from 25,000 BPSD to 26,000 BPSD as a result of continued improvements and advancements at the refinery. The Woods Cross Refinery is located in Woods Cross, Utah and processes regional sweet and black wax crude as well as Canadian sour crude oils into high value light products. For 2006, gasoline, diesel and jet fuel (excluding volumes purchased for resale) represented 63%, 28% and 2%, respectively, of the Woods Cross Refinery s sales volumes.

The following table sets forth information about the Woods Cross Refinery operations, including non-GAAP performance measures about our refinery operations. The cost of products and refinery gross margin do not include the effect of depreciation, depletion and amortization. Reconciliations to amounts reported under GAAP are provided under Reconciliations to Amounts Under Generally Accepted Accounting Principles following Item 7A of Part II of this Form 10-K.

	Years Ended December 31,		
	2006	2005	2004
Woods Cross Refinery			
Crude Charge (BPD) (1)	23,640	24,100	23,620
Refinery production (BPD) (2)	25,190	25,850	23,730
Sales of produced refined products (BPD)	25,150	26,390	23,520
Sales of refined products (BPD) (3)	26,210	27,710	24,160
Refinery utilization (4)	90.9%	92.7%	94.5%
Average per produced barrel (5)			
Net sales	$ 82.09	$ 69.13	$ 51.33
Cost of products (6)	64.99	59.51	45.33
Refinery gross margin	17.10	9.62	6.00
Refinery operating expenses (7)	5.13	4.61	3.92
Net operating margin	$ 11.97	$ 5.01	$ 2.08
Feedstocks:			
Sour crude oil	2%	8%	7%
Sweet crude oil	89%	82%	88%
Other feedstocks and blends	9%	10%	5%
Total	100%	100%	100%

(1) Crude charge represents the barrels per day of crude oil processed at the refinery.

(2) Refinery production represents the barrels per day of refined products yielded from processing crude and other feedstocks at the refinery.

(3) Includes refined products

purchased for resale.

(4) Represents crude charge divided by total crude capacity (BPSD).

(5) Represents average per barrel amount for produced refined products sold, which is a non-GAAP measure. Reconciliations to amounts reported under GAAP are located under Reconciliations to Amounts Reported Under Generally Accepted Accounting Principles following Item 7A of Part II of this Form 10-K.

(6) Subsequent to the formation of HEP, transportation costs billed from HEP are included in cost of products.

(7) Represents operating expenses of the refinery, exclusive of depreciation, depletion and amortization,

and excludes refining segment expenses of product pipelines and terminals.

The Woods Cross Refinery facility is located on a 200 acre site and is a fully integrated refinery with crude distillation, solvent deasphalter, FCC, HF alkylation, catalytic reforming, hydrodesulfurization, isomerization, sulfur recovery, and product blending units. Other supporting infrastructure includes approximately 1.5 million barrels of feedstock and product tankage, maintenance shops, warehouses and office buildings. The operating units at the Woods Cross facility include newly constructed units, older units that have been relocated from other facilities, upgraded and re-erected in Woods Cross, and units that have been operating as part of the Woods Cross facility (with periodic major maintenance) for many years, in some very limited cases since before 1950. The crude oil capacity of the Woods Cross facility is 26,000 BPSD and the facility typically processes or blends an additional 2,000 BPSD of natural gasoline, butane, and gas oil.

We operate approximately 5 miles of crude, refined products and hydrogen pipelines that allow us to connect our Woods Cross Refinery to common carrier pipeline systems and to a hydrogen plant located at Chevron s Salt Lake Refinery.

Markets and Competition

The Woods Cross Refinery is one of five refineries located in Utah. We estimate that the four refineries that compete with our Woods Cross Refinery have a combined capacity to process approximately 146,000 BPD of crude oil. The five Utah refineries collectively supply an estimated 70% of the gasoline and distillate products consumed in the states of Utah and Idaho, with the remainder imported from refineries in Wyoming and Montana via the Pioneer Pipeline owned jointly by Sinclair and ConocoPhillips. The Woods Cross Refinery s primary markets include Utah, Idaho, Nevada and Wyoming. Approximately 65% of the gasoline and diesel fuel produced by our Woods Cross Refinery are sold through a network of Phillip 66 branded marketers.

Utah Market

The Utah market for refined products is currently supplied by a number of refiners and the Pioneer pipeline. Refiners include Woods Cross, Chevron, Tesoro, Big West, Silver Eagle, Sinclair, and ConocoPhillips. Pipelines include Pioneer. We currently supply approximately 16,000 BPD of refined products into the Utah market, which represents approximately 15% of the refined products consumed in that market, to branded and unbranded customers.

Idaho, Wyoming, Eastern Washington and Nevada Markets

The Idaho, Wyoming, Washington and Nevada markets for refined products are also currently supplied by a number of refiners and pipelines. Refiners include Woods Cross, Chevron, Tesoro, Big West, Silver Eagle, Sinclair, ConocoPhillips and Exxon. Pipelines include Chevron and Yellowstone common carrier pipelines. We currently supply approximately 7,500 BPD of refined products into the Idaho, Wyoming, Washington and Nevada markets, which represents approximately 2% of the refined products consumed in those markets. Woods Cross ships via common carrier pipeline to numerous terminals, including HEP s terminals at Boise and Burley, Idaho and Spokane, Washington, and sells to branded and unbranded customers. We also truck refined products to Nevada.

Principal Products and Customers

Set forth below is information regarding the principal products produced at the Woods Cross Refinery since our acquisition in June 2003.

	Years Ended December 31,		
	2006	2005	2004
Woods Cross Refinery			
Sales of produced refined products:			
Gasolines	63%	60%	59%
Diesel fuels	28%	29%	31%
Jet fuels	2%	2%	1%
Fuel oils	5%	7%	7%
LPG and other	2%	2%	2%
Total	100%	100%	100%

Light products are shipped by product pipelines or are made available at various points by exchanges with others. Light products are also made available to customers through truck loading facilities at the refinery and at terminals. Our principal customers for gasoline include other refiners, convenience store chains, independent marketers and retailers. The composition of gasoline differs, due to local regulatory requirements, depending on the area in which gasoline is to be sold. Diesel fuel is sold to other refiners, truck stop chains, and wholesalers. Jet fuel is sold primarily for military use. All asphalt produced is blended to fuel oil and sold locally, railed to the gulf coast or marketed through Holly Asphalt Company to governmental entities or contractors. LPG s are sold to LPG wholesalers and LPG retailers.

Military jet fuel is sold to the DESC under a series of one-year contracts that can vary significantly from year to year. We sold approximately 500 BPD of jet fuel to the DESC in 2006. Our size in terms of employees and refining capacity allows us to bid for military jet fuel sales contracts under a small business set-aside program. In September 2006, DESC awarded us contracts for sales of military jet fuel for the period October 1, 2006 through September 30, 2007. Our total contract award, which is subject to adjustment based on actual needs of the DESC for military jet fuel, was approximately 8 million gallons as compared to the total award for the 2005-2006 contract year of approximately 2 million gallons. The loss of our military jet fuel contract with the United States Government could have an adverse effect on our results of operations if alternate commercial jet fuel or additional diesel fuel sales could not be secured.

Crude Oil and Feedstock Supplies

The Woods Cross Refinery currently obtains its supply of crude oil primarily from suppliers in Canada, Wyoming, Utah and Colorado via common carrier pipelines, which originate in Canada, Wyoming and Colorado.

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On February 27, 2007, we entered into a definitive agreement with Berry Petroleum Company to purchase black wax crude oil for six years, effective July 1, 2007. We have committed to purchase an initial volume of 3,200 BPD, increasing to 5,000 BPD upon completion of certain capacity expansion projects at our Woods Cross Refinery. Pricing will be calculated at a discount from then-prevailing market rates.

Capital Improvement Projects

In 2006 we completed a clean fuels project at the Woods Cross Refinery. The project included the construction of a diesel hydrotreater unit, at an approximate cost of $35.0 million, which was approved in prior years, and entered into a long-term hydrogen supply contract that has enabled the Woods Cross Refinery to produce ULSD.

Our approved capital budget for 2007 capital projects at the Woods Cross Refinery is $9.7 million not including the major projects described below or other capital projects approved in prior years. As announced in December 2006, we will be adding a new 15,000 BPD hydrocracker along with sulfur recovery and desalting equipment at our Woods Cross Refinery. The budgeted cost of these additions is approximately $100.0 million. These additions will expand the Woods Cross Refinery s crude processing capabilities from 26,000 BPD to 31,000 BPD while enabling the refinery to process up to 10,000 BPD of high-value low-priced black wax crude oil and up to 5,000 BPD of low-priced heavy Canadian crude oils. This expansion project as approved involves a higher capital investment than had originally been estimated, principally because of the substitution of a complex hydrocracker in place of certain desulfurization and expanded bottoms-processing modifications that had been included in preliminary planning. The substitution of the complex hydrocracker is expected to provide increased capabilities to process significantly more black wax crude oils, which have recently been priced at substantial discounts to West Texas Intermediate crude oil while yielding substantially higher value products than the discounted heavy Canadian crudes that were a more significant part of the original plan. These additions would also increase the refinery s capacity to process low-cost feedstocks and provide the necessary infrastructure for future expansions of crude oil refining capacity at the Woods Cross Refinery. The approved projects for the Woods Cross refinery are expected to be completed during the fourth quarter of 2008.

To fully take advantage of the economics on the Woods Cross expansion project, additional crude pipeline capacity will be required to move Canadian crude to the Woods Cross Refinery. In February 2007, HEP entered into a letter of intent with Plains under which HEP will own a 25% interest in a new 95 mile intrastate pipeline system, now being constructed by Plains, which will have the capacity to ship up to 120,000 BPD of crude oil into the Salt Lake City area.

Additionally, we are also working with HEP to evaluate a refined products pipeline from Salt Lake City to Las Vegas. The current estimated cost of this pipeline is expected to be approximately $235.0 million, and the total cost of the project including terminals is expected to be approximately $300.0 million.

HOLLY ENERGY PARTNERS, L.P.

In July 2004, we completed the initial public offering of limited partnership interests in HEP, a Delaware limited partnership that also trades on the New York Stock Exchange under the trading symbol HEP . HEP was formed to acquire, own and operate substantially all of the refined product pipeline and terminalling assets that support our refining and marketing operations in west Texas, New Mexico, Utah and Arizona and a 70% interest in Rio Grande. On February 28, 2005, HEP closed on a contribution agreement with Alon and several of its wholly-owned subsidiaries that provided for HEP s acquisition of four refined products pipelines, an associated tank farm and two refined products terminals located primarily in Texas. On July 8, 2005, we closed on a transaction for HEP to acquire our two 65-mile parallel intermediate feedstock pipelines which connect our Lovington and Artesia, New Mexico facilities, a transaction which diluted our ownership interest in HEP to 45.0%. We initially consolidated the results of HEP and showed the interest we did not own as a minority interest in ownership and earnings. Under the provisions of FIN 46, we have deconsolidated HEP effective July 1, 2005. From July 1, 2005 forward, our share of the earnings of HEP is reported using the equity method of accounting. For additional information about the formation of HEP and the subsequent Alon and intermediate pipelines transactions, see Note 3 in the Notes to Consolidated Financial Statements under Item 8, Financial Statements and Supplementary Data.

HEP operates a system of petroleum pipelines and distribution terminals in Texas, New Mexico, Utah, Arizona, Idaho, Washington and Oklahoma. HEP generates revenues by charging tariffs for transporting petroleum products

through its pipelines, by leasing certain pipeline capacity to Alon, by charging fees for terminalling refined products and other hydrocarbons and storing and providing other services at its terminals. HEP does not take ownership of products that it transports or terminals and therefore is not directly exposed to changes in commodity prices. HEP serves our refineries in New Mexico and Utah under a 15-year pipelines and terminals agreement (HEP PTA) expiring 2019 and the 15-year intermediate pipelines agreement expiring 2020 (HEP IPA). The agreements provide that we transport or terminal volumes on certain of HEP s facilities that will result in minimum annual payments to HEP, currently $38.5 million under the HEP PTA and $12.4 million under the HEP IPA. In addition, we have agreed to indemnify HEP, subject to certain limits, for any historical environmental noncompliance and remediation liabilities.

The substantial majority of HEP s business is devoted to providing transportation and terminalling services to us. HEP s assets include:

Pipelines:

- approximately 780 miles of refined product pipelines, including 340 miles of leased pipelines, that transport gasoline, diesel, and jet fuel principally from our Navajo Refinery in New Mexico to our customers in the metropolitan and rural areas of Texas, New Mexico, Arizona, Colorado, Utah and northern Mexico;
- approximately 510 miles of refined product pipelines that transport refined products from Alon s Big Spring refinery in Texas to customers in Texas and Oklahoma;
- two parallel 65-mile pipelines that transport intermediate feedstocks and crude oil from our Lovington, New Mexico refinery facilities to our Artesia, New Mexico refining facilities; and
- a 70% interest in Rio Grande, a joint venture that owns a 249-mile refined product pipeline that transports liquid petroleum gases, or LPG s, from west Texas to the Texas/Mexico border near El Paso for further transport into northern Mexico.

Refined Product Terminals:

- five refined product terminals (one of which is 50% owned), located in El Paso, Texas; Moriarty, Bloomfield and Albuquerque, New Mexico; and Tucson, Arizona, with an aggregate capacity of approximately 1.1 million barrels, that are integrated with HEP s refined product pipeline system that serves our Navajo Refinery;
- three refined product terminals (two of which are 50% owned), located in Burley and Boise, Idaho and Spokane, Washington, with an aggregate capacity of approximately 500,000 barrels, that serve third-party common carrier pipelines;
- one refined product terminal near Mountain Home, Idaho with a capacity of 120,000 barrels, that serves a nearby United States Air Force Base;
- two refined product terminals, located in Wichita Falls and Abilene, Texas, and one tank farm in Orla, Texas with aggregate capacity of 480,000 barrels, that are integrated with HEP s refined product pipelines that serve Alon s Big Spring, Texas refinery; and
- two refined product truck loading racks, one located within our Navajo Refinery that is permitted to load over 40,000 BPD of light refined products, and one located within our Woods Cross Refinery near Salt Lake City, Utah, that is permitted to load over 25,000 BPD of light refined products.

Pipeline Transportation Business

Prior to the initial public offering of HEP on July 13, 2004, certain of our pipelines and terminals were included as part of the pipeline transportation business division. After the offering, the pipelines and terminals that remained became part of the Refining business division. In years prior to the initial public offering of HEP, we developed the pipeline transportation business to generate revenues from unaffiliated parties. The pipeline transportation operations included certain refined product pipelines, the interest in Rio Grande and terminalling agreements that were contributed to HEP along with certain crude oil pipelines that were not contributed to HEP. The following paragraphs provide historic information relating to the assets that were previously included in our pipeline transportation division. Rio Grande is 70% owned by HEP and 30% owned by BP p.l.c., and serves northern Mexico by transporting LPG s from a point near Odessa, Texas to a subsidiary of PEMEX at a point near El Paso, Texas. The PEMEX subsidiary then transports the LPG s to its Mendez terminal near Juarez, Mexico. Deliveries by the joint venture began in April 1997. Prior to the initial public offering of HEP on July 13, 2004, Rio Grande was owned 70% by us and 30% by

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BP p.l.c. Prior to June 30, 2003, Rio Grande was owned 25% by us and 75% collectively by two parties unaffiliated with us. On June 30, 2003, we purchased an additional 45% interest in Rio Grande, through a wholly-owned subsidiary, adding to the 25% interest that our subsidiary already owned.

In 1998, we implemented an alliance with FINA, Inc. (FINA) to create a comprehensive supply network to substantially increase the supplies of gasoline and diesel fuel in the west Texas, New Mexico, and Arizona markets to meet expected increasing demand in the future. FINA constructed a 50 mile pipeline that connected an existing FINA pipeline system to our 12-inch/8-inch pipeline between Orla and El Paso, Texas. In August 1998, FINA began transporting to El Paso, pursuant to a long-term lease of certain capacity of our 12-inch pipeline, gasoline and diesel fuel from its Big Spring, Texas refinery, and we began to realize pipeline rental and terminalling revenues from FINA under these agreements. In August 2000, Alon succeeded to FINA s interest in this alliance. Effective from February 2002, Alon transports up to 20,000 BPD to El Paso on this interconnected system.

In the second quarter of fiscal 2000, we acquired certain crude oil pipeline transportation and storage assets located in west Texas and New Mexico in an asset exchange with ARCO Pipeline Company. The acquired assets, including 100 miles of pipelines and over 250,000 barrels of tankage, allow us to transport crude oil for unaffiliated companies and increase our ability to access additional crude oil for the Navajo Refinery.

ADDITIONAL OPERATIONS AND OTHER INFORMATION

Corporate Offices

We lease our principal corporate offices in Dallas, Texas. The lease for our principal corporate offices expires June 30, 2011, requires lease payments of approximately $137,000 per month plus certain operating expenses and provides for one five-year renewal period. Functions performed in the Dallas office include overall corporate management, refinery and HEP management, planning and strategy, corporate finance, crude acquisition, logistics, contract administration, marketing, investor relations, governmental affairs and accounting, tax, treasury, information technology, legal and human resources support functions.

Exploration and Production

We conduct a small-scale oil and gas exploration and production program. We have not budgeted any significant amounts for these activities in 2007.

Other Investments

Prior to February 28, 2005, we had a 49% interest in MRC Hi-Noon LLC, a joint venture operating retail service stations and convenience stores in Montana, and we accounted for our share of earnings from the joint venture using the equity method. At December 31, 2004, we had a reserve balance of approximately $0.8 million related to the collectability of advances to the joint venture and related accrued interest. On February 28, 2005, we sold our 49% interest to our joint venture partner and agreed to accept partial payment on the advances we previously made to the joint venture. In connection with this transaction, we received $0.8 million, which resulted in a book gain to us of $0.5 million.

Employees and Labor Relations

As of December 31, 2006, we had 859 employees, of which 295 are covered by collective bargaining agreements that expire during 2009 and 2010. We consider our employee relations to be good.

Regulation

Refinery and pipeline operations are subject to federal, state and local laws regulating the discharge of matter into the environment or otherwise relating to the protection of the environment. Permits are required under these laws for the operation of our refineries, pipelines and related operations, and these permits are subject to revocation, modification and renewal. Over the years, there have been and continue to be ongoing communications, including notices of violations, and discussions about environmental matters between us and federal and state authorities, some of which have resulted or will result in changes to operating procedures and in capital expenditures. Compliance with applicable environmental laws, regulations and permits will continue to have an impact on our operations, results of operations and capital requirements. We believe that our current operations are in substantial compliance with existing environmental laws, regulations and permits.

Our operations and many of the products we manufacture are subject to certain specific requirements of the Federal Clean Air Act (CAA) and related state and local regulations. The CAA contains provisions that require capital expenditures for the installation of certain air pollution control devices at our refineries. Subsequent rule making authorized by the CAA or similar laws or new agency interpretations of existing rules, may necessitate additional expenditures in future years.

In December 2001, we entered into an agreement for a Consent Decree (Consent Agreement) with the EPA and the New Mexico Environment Department of Environmental Quality with respect to a global settlement of issues concerning the application of air quality requirements to past and future operations of our Navajo Refinery. The Consent Agreement requires us to make investments at our Navajo Refinery for the installation of certain state of the art pollution control equipment currently expected to total approximately $14.0 million over a period expected to end in 2010, of which approximately $13.1 million has been expended to date.

The EPA and the State of Utah have asserted that we have CAA liabilities relating to our Woods Cross Refinery because of actions taken or not taken by prior owners of the Woods Cross Refinery, which we purchased from ConocoPhillips in June 2003. We have tentatively agreed with the EPA and the State of Utah to settle the issues presented by means of an agreement similar to the 2001 Consent Agreement we entered into for our Navajo and Montana refineries. The tentative settlement agreement, which has not yet been put into a final written agreement, includes proposed obligations for us to make specified additional capital investments expected to total up to approximately $10.0 million over several years and to make changes in operating procedures at the refinery. The agreements for the purchase of the Woods Cross Refinery provide that ConocoPhillips will indemnify us, subject to specified limitations, for environmental claims arising from circumstances prior to our purchase of the refinery. We believe that, in the present circumstances, the amount due to us from ConocoPhillips under the agreements for the purchase of the Woods Cross Refinery would be approximately $1.4 million with respect to the tentative settlement.

Under the CAA, the EPA has the authority to modify the formulation of the refined transportation fuel products we manufacture in order to limit the emissions associated with their final use. For example, in December 1999, the EPA promulgated national regulations limiting the amount of sulfur allowable in gasoline. The new regulations required the phase-in of gasoline sulfur standards beginning in 2004, with special provisions for small refiners and for refiners serving those western states exhibiting lesser air quality problems. Subsequently, the EPA promulgated regulations further limiting the sulfur content of highway fuel to 15 PPM. The EPA believes such limits are necessary to protect new automobile emission control systems that may be inhibited by sulfur in the fuel.

In June 2004, the EPA issued new regulations limiting emissions from diesel fuel powered engines used in non-road activities such as mining, construction, agriculture, railroad and marine and simultaneously limiting the sulfur content of diesel fuel used in these engines to facilitate compliance with the new emission standards. Although the highway and non-road diesel sulfur regulations provided for a timed phase-in of the low sulfur requirements with extended compliance dates for small refiners such as us, both of our refineries met the ultimate 15 PPM standard for both our non-road and highway diesel fuel by June 1, 2006, the earliest deadline for large refiners. This entailed substantial capital expenditures; however, these capital expenditures would have been required later. Our early compliance with this initiative enabled us to obtain additional small refiner extensions on the low sulfur gasoline requirements.

We are currently reviewing a new EPA regulation on gasoline that would impose further reductions in the benzene content of our produced gasoline and another EPA regulation, currently under development, that would mandate the

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blending of prescribed, substantial percentages of renewable fuels (i.e. ethanol) into our produced gasoline. Both of these initiatives contain mitigating provisions for small refiners such as us. These new requirements, other requirements of the CAA, and other presently existing or future environmental regulations may cause us to make substantial capital expenditures to enable our refineries to produce products that meet applicable requirements.

Our operations are also subject to the Federal Clean Water Act (CWA), the Federal Safe Drinking Water Act (SDWA) and comparable state and local requirements. The CWA, the SDWA and analogous laws prohibit any discharge into surface waters, ground waters and publicly-owned treatment works except in strict conformance with permits, such as pre-treatment permits and National Pollutant Discharge Elimination System (NPDES) permits, issued by federal, state and local governmental agencies. NPDES permits and analogous water discharge permits are valid for a maximum of five years and must be renewed.

We generate wastes that may be subject to the Resource Conservation and Recovery Act and comparable state and local requirements. The EPA and various state agencies have limited the approved methods of disposal for certain hazardous and non-hazardous wastes.

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as Superfund, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed of or arranged for the disposal of the hazardous substances. Under CERCLA, such persons may be subject to joint and several liabilities for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Analogous state laws impose similar responsibilities and liabilities on responsible parties. In the course of our historical operations, as well as in our current normal operations, we have generated waste, some of which falls within the statutory definition of a hazardous substance and some of which may have been disposed of at sites that may require cleanup under Superfund.

As is the case with all companies engaged in industries similar to ours, we face potential exposure to future claims and lawsuits involving environmental matters. The matters include soil and water contamination, air pollution, personal injury and property damage allegedly caused by substances which we manufactured, handled, used, released or disposed of.

We are and have been the subject of various state, federal and private proceedings relating to environmental regulations, conditions and inquiries, including those discussed above. Current and future environmental regulations are expected to require additional expenditures, including expenditures for investigation and remediation, which may be significant, at our refineries and at pipeline transportation facilities. To the extent that future expenditures for these purposes are material and can be reasonably determined, these costs are disclosed and accrued.

Our operations are also subject to various laws and regulations relating to occupational health and safety. We maintain safety, training and maintenance programs as part of our ongoing efforts to ensure compliance with applicable laws and regulations. Compliance with applicable health and safety laws and regulations has required and continues to require substantial expenditures.

We cannot predict what additional health and environmental legislation or regulations will be enacted or become effective in the future or how existing or future laws or regulations will be administered or interpreted with respect to our operations. Compliance with more stringent laws or regulations or adverse changes in the interpretation of existing regulations by government agencies could have an adverse effect on the financial position and the results of our operations and could require substantial expenditures for the installation and operation of systems and equipment that we do not currently possess.

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Insurance
Our operations are subject to normal hazards of operations, including fire, explosion and weather-related perils. We maintain various insurance coverages, including business interruption insurance, subject to certain deductibles. We are not fully insured against certain risks because such risks are not fully insurable, coverage is unavailable, or premium costs, in our judgment, do not justify such expenditures.

Item 1A. Risk Factors

Investing in us involves a degree of risk, including the risks described below. Our operating results have been, and will continue to be, affected by a wide variety of risk factors, many of which are beyond our control, that could have adverse effects on profitability during any particular period. You should carefully consider the following risk factors together with all of the other information included in this Annual Report on Form 10-K, including the financial statements and related notes, when deciding to invest in us. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may also materially and adversely affect our business operations. If any of the following risks were to actually occur, our business, financial condition or results of operations could be materially and adversely affected.

The prices of crude oil and refined products materially affect our profitability, and are dependent upon many factors that are beyond our control, including general market demand and economic conditions, seasonal and weather-related factors and governmental regulations and policies.

Among these factors is the demand for crude oil and refined products, which is largely driven by the conditions of local and worldwide economies as well as by weather patterns and the taxation of these products relative to other energy sources. Governmental regulations and policies, particularly in the areas of taxation, energy and the environment, also have a significant impact on our activities. Operating results can be affected by these industry factors, by competition in the particular geographic areas that we serve and by factors that are specific to us, such as the success of particular marketing programs and the efficiency of our refinery operations. The demand for crude oil and refined products can also be reduced due to a local or national recession or other adverse economic condition that results in lower spending by businesses and consumers on gasoline and diesel fuel, higher gasoline prices due to higher crude oil prices, a shift by consumers to more fuel-efficient vehicles or alternative fuel vehicles (such as ethanol or wider adoption of gas/electric hybrid vehicles), or an increase in vehicle fuel economy, whether as a result of technological advances by manufacturers, legislation mandating or encouraging higher fuel economy or the use of alternative fuel.

In addition, our profitability depends largely on the spread between market prices for refined petroleum products and crude oil prices. This margin is continually changing and may fluctuate significantly from time to time. Crude oil and refined products are commodities whose price levels are determined by market forces beyond our control. Additionally, due to the seasonality of refined products markets and refinery maintenance schedules, results of operations for any particular quarter of a fiscal year are not necessarily indicative of results for the full year. In general, prices for refined products are influenced by the price of crude oil. Although an increase or decrease in the price for crude oil may result in a similar increase or decrease in prices for refined products, there may be a time lag in the realization of the similar increase or decrease in prices for refined products. The effect of changes in crude oil prices on operating results therefore depends in part on how quickly refined product prices adjust to reflect these changes. A substantial or prolonged increase in crude oil prices without a corresponding increase in refined product prices, a substantial or prolonged decrease in refined product prices without a corresponding decrease in crude oil prices, or a substantial or prolonged decrease in demand for refined products could have a significant negative effect on our earnings and cash flows.

We may not be able to successfully execute our business strategies to grow our business.

One of the ways we may grow our business is through the construction of new refinery processing units (or the purchase and refurbishment of used units from another refinery) and the expansion of existing ones. Projects are generally initiated to increase the yields of higher-value products, increase refinery production capacity, meet new governmental requirements, or maintain the operations of our existing assets. The construction process involves numerous regulatory, environmental, political, and legal uncertainties, most of which are not fully within our

control. These projects may not be completed on schedule or at all or at the budgeted cost. In addition, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new refinery processing unit, the construction will occur over an extended period of time and we will not receive any material increases in revenues until after completion of the project. Moreover, we may construct facilities to capture anticipated future growth in demand for refined products in a region in which such growth does not materialize. As a result, new capital investments may not achieve our expected investment return, which could adversely affect our results of operations and financial condition.

In addition, a component of our growth strategy is to selectively acquire complementary assets for our refining operations in order to increase earnings and cash flow. Our ability to do so will be dependent upon a number of factors, including our ability to identify attractive acquisition candidates, consummate acquisitions on favorable terms, successfully integrate acquired assets and obtain financing to fund acquisitions and to support our growth, and other factors beyond our control. We may not be successful in acquiring additional assets, and any acquisitions that we do consummate may not produce the anticipated benefits or may have adverse effects on our business and operating results.

To successfully operate our petroleum refining facilities, we are required to expend significant amounts for capital outlays and operating expenditures.

The refining business is characterized by high fixed costs resulting from the significant capital outlays associated with refineries, terminals, pipelines and related facilities. We are dependent on the production and sale of quantities of refined products at refined product margins sufficient to cover operating costs, including any increases in costs resulting from future inflationary pressures or market conditions and increases in costs of fuel and power necessary in operating our facilities. Furthermore, future regulatory requirements or competitive pressures could result in additional capital expenditures, which may or may not produce the results intended. Such capital expenditures may require significant financial resources that may be contingent on our access to capital markets and commercial bank loans. Additionally, other matters, such as regulatory requirements or legal actions, may restrict our access to funds for capital expenditures.

We may incur significant costs to comply with new or changing environmental, health and safety laws and regulations, and face potential exposure for environmental matters.

Refinery and pipeline operations are subject to federal, state and local laws regulating the discharge of matter into the environment or otherwise relating to the protection of the environment. Permits are required under these laws for the operation of our refineries, pipelines and related operations, and these permits are subject to revocation, modification and renewal. Over the years, there have been and continue to be ongoing communications, including notices of violations, and discussions about environmental matters between us and federal and state authorities, some of which have resulted or will result in changes to operating procedures and in capital expenditures. Compliance with applicable environmental laws, regulations and permits will continue to have an impact on our operations, results of operations and capital requirements.

As is the case with all companies engaged in industries similar to ours, we face potential exposure to future claims and lawsuits involving environmental matters. The matters include soil and water contamination, air pollution, personal injury and property damage allegedly caused by substances which we manufactured, handled, used, released or disposed of.

We are and have been the subject of various state, federal and private proceedings relating to environmental regulations, conditions and inquiries. Current and future environmental regulations are expected to require additional expenditures, including expenditures for investigation and remediation, which may be significant, at our facilities. To the extent that future expenditures for these purposes are material and can be reasonably determined, these costs are disclosed and accrued.

Our operations are also subject to various laws and regulations relating to occupational health and safety. We maintain safety, training and maintenance programs as part of our ongoing efforts to ensure compliance with applicable laws and regulations. Compliance with applicable health and safety laws and regulations has required and continues to require substantial expenditures.

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We cannot predict what additional health and environmental legislation or regulations will be enacted or become effective in the future or how existing or future laws or regulations will be administered or interpreted with respect to our operations. Compliance with more stringent laws or regulations or adverse changes in the interpretation of existing regulations by government agencies could have an adverse effect on the financial position and the results of our operations and could require substantial expenditures for the installation and operation of systems and equipment that we do not currently possess.

For additional information on regulations and related liabilities or potential liabilities affecting our business, see Regulation under Items 1 and 2, Business and Properties.

Competition in the refining and marketing industry is intense, and an increase in competition in the markets in which we sell our products could adversely affect our earnings and profitability.

We compete with a broad range of refining and marketing companies, including certain multinational oil companies. Because of their geographic diversity, larger and more complex refineries, integrated operations and greater resources, some of our competitors may be better able to withstand volatile market conditions, to obtain crude oil in times of shortage and to bear the economic risks inherent in all phases of the refining industry.

We are not engaged in any significant petroleum exploration and production activities and do not produce any of the crude oil feedstocks used at our refineries. We do not have a retail business and therefore are dependent upon others for outlets for our refined products. Certain of our competitors, however, obtain a portion of their feedstocks from company-owned production and have 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. 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, there could be material adverse effects on our business, financial condition and results of operations.

In recent years there have been several refining and marketing consolidations or acquisitions between entities competing in our geographic market. These transactions could increase the future competitive pressures on us.

Other refiners could expand existing facilities or build new ones in our markets and significantly affect our profitability. For example, Arizona Clean Fuels Yuma, LLC has obtained a permit to construct a 150,000 BPD refinery in Arizona and is currently seeking financing for that project. Another example is the proposed merger of Western Refining, Inc. and Giant Industries, Inc., who are considering utilizing currently idle refining capacity in the Four Corners area of New Mexico.

We may not be able to retain existing customers or acquire new customers.

The renewal or replacement of existing sales agreements with our customers depends on a number of factors outside our control, including competition from other refiners and the demand for refined products in the markets that we serve. Loss of, or reduction in amounts purchased by our major customers could have an adverse effect on us to the extent that, because of market limitations or transportation constraints, we are not able to correspondingly increase sales to other purchasers.

A material decrease in the supply of crude oil available to our refineries could significantly reduce our production levels.

In order to maintain or increase production levels at our refineries, we must continually contract for new crude oil supplies. A material decrease in crude oil production from the fields that supply our refineries, as a result of depressed commodity prices, lack of drilling activity, natural production declines or otherwise, could result in a decline in the volume of crude oil available to our refineries. Such an event could result in an overall decline in volumes of refined products processed at our refineries and therefore a corresponding reduction in our cash flow. In addition, the future growth of our operations will depend in part upon whether we can contract for additional supplies of crude oil at a greater rate than the rate of natural decline in our currently connected supplies.

The potential operation of new refined product transportation pipelines or proration of existing pipelines could impact the supply of refined products to our existing markets, including El Paso, Albuquerque and Phoenix.

The Longhorn Pipeline was recently purchased by Flying J Inc. (Flying J) and is transporting refined products from gulf coast refineries to El Paso. This pipeline is approximately 700 miles long and runs from the Houston area to El Paso, utilizing a direct route. The previous owner, Longhorn Partners Pipeline, L.P., had announced that it would use the pipeline initially to transport approximately 72,000 BPD of refined products from the gulf coast to El Paso and markets served from El Paso, with an ultimate maximum capacity of 225,000 BPD. Since inception of Longhorn operations in late 2005, it is our understanding that there have been some shipments (substantially under the 72,000 BPD rate) of refined products. Since the purchase by Flying J, volumes shipped on Longhorn have been increasing. We understand Flying J is expanding the truck rack at its El Paso terminal to increase truck loading capacity and has a large fleet of trucks serving markets as far away as Arizona. Flying J has significantly increased the volume of gulf coast refined products shipped into El Paso and is actively exploring options to ship additional product on the SFPP system into Arizona, the Plains system into New Mexico, and into Mexico. However, any effects on our markets in Tucson and Phoenix, Arizona and Albuquerque, New Mexico are expected to be limited in the near-term because current common carrier pipelines from El Paso to these markets are now running at capacity and proration policies of these pipelines allocate only limited capacity to new shippers. Plains, which acquired from Chevron in 2006 the common carrier pipeline from El Paso to Albuquerque, is currently evaluating an expansion of this pipeline dependent upon support of its existing and potential shippers.

In August 2006, SFPP expanded the capacity of its pipeline from El Paso to the Arizona market by between 45,000 and 50,000 BPD. SFPP announced a further planned expansion of the capacity of this pipeline from El Paso to the Arizona market by 23,000 BPD, with an expected completion date at the end of 2007 or first quarter of 2008. Although our results of operations might be adversely impacted by Longhorn, the expansions of the Plains pipeline, or the further expansion of SFPP s El Paso-to-Arizona pipeline, we are unable to predict at this time the extent to which we could be negatively affected.

An additional factor that could affect some of our markets is the presence of excess pipeline capacity from the west coast into our Arizona markets. If refined products become available on the west coast in excess of demand in that market, additional products may be shipped into our Arizona markets with resulting possible downward pressure on refined product prices in these markets.

In addition to the projects described above, other projects have been explored from time to time by refiners and other entities which if completed, could result in further increases in the supply of products to our markets.

The common carrier pipelines we use to serve the Arizona and Albuquerque markets are currently operated at or near capacity and are subject to proration. As a result, the volumes of refined products that we and other shippers have been able to deliver to these markets have been limited. The flow of additional products into El Paso for shipment to Arizona, either as a result of Longhorn or otherwise, could further exacerbate such constraints on our deliveries to Arizona. No assurances can be given that we will not experience future constraints on our ability to deliver products through the common carrier pipeline to Arizona. Any future constraints on our ability to transport refined products to Arizona could, if sustained, adversely affect our results of operations and financial condition. As mentioned above, SFPP has announced plans to expand the capacity of its pipeline from El Paso to the Arizona market. The proposed expansion would permit us to ship additional refined products to markets in Arizona, but pipeline tariffs would likely be higher and the expansion would also permit additional shipments by competing suppliers. The ultimate effects of SFPP s proposed pipeline expansion on us cannot presently be estimated.

In the case of the Albuquerque market, the common carrier pipeline we use to serve this market out of El Paso currently operates at or near capacity with resulting limitations on the amount of refined products that we and other shippers can deliver. However, through our relationship with HEP, we have access to pipelines running from near the Navajo Refinery to the Albuquerque vicinity and Bloomfield, New Mexico, that will permit us to deliver a total of up to 45,000 BPD of light products to these locations, thereby eliminating the risk of future pipeline constraints on shipments to Albuquerque. If needed, additional pump stations could further increase HEP s pipeline

capabilities. Any future constraints on our ability to transport refined products to Arizona or Albuquerque could, if sustained, adversely affect our results of operations and financial condition.

For additional information on competition in our markets due to new product transportation pipelines or proration of existing pipelines, see Markets and Competition under the Navajo Refinery discussion under Items 1 and 2, Business and Properties.

We depend upon HEP for a substantial portion of the distribution network for our refined products and we own a significant equity interest in HEP.

We currently own a 45% interest in HEP, including the 2% general partner interest. HEP operates a system of refined product pipelines and distribution terminals in Texas, New Mexico, Utah, Arizona, Idaho, Washington and Oklahoma. HEP generates revenues by charging tariffs for transporting refined products through its pipelines, by leasing certain pipeline capacity to Alon, by charging fees for terminalling refined products and other hydrocarbons and storing and providing other services at its terminals. HEP serves our refineries in New Mexico and Utah under two 15 year pipelines and terminals agreements expiring in 2019 and 2020. The agreements provide that we transport or terminal volumes on certain of HEP s facilities that result in revenues to HEP at least equal to specified minimum revenue amounts annually. Furthermore, through our 45% ownership of HEP, we record our share of HEP s earnings and receive distributions from HEP. HEP is subject to its own operating and regulatory risks, including, but not limited to:

- its reliance on its significant customers, including us,
- competition from other pipelines,
- environmental regulations affecting pipeline operations,
- operational hazards and risks,
- pipeline tariff regulations affecting the rates HEP can charge,
- limitations on additional borrowings and other restrictions due to HEP s debt covenants, and
- other financial, operational and legal risks.

The occurrence of any of these risks adversely impacting HEP could affect our distribution system or the earnings and cash flows we receive from HEP and thereby adversely affect our results of operations and financial condition.

For additional information about HEP, see Holly Energy Partners, L.P. under Items 1 and 2, Business and Properties.

Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured.

Our operations are subject to operational hazards and unforeseen interruptions such as natural disasters, adverse weather, accidents, fires, explosions, hazardous materials releases, mechanical failures and other events beyond our control. These events might result in a loss of equipment or life, injury, or extensive property damage, as well as an interruption in our operations. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased, and could increase further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position.

If we lose any of our key personnel, our ability to manage our business and continue our growth could be negatively impacted.

Our future performance depends to a significant degree upon the continued contributions of our senior management team and key technical personnel. We do not currently maintain key man life insurance with respect to any member of our senior management team. The loss or unavailability to us of any member of our senior management team or a key technical employee could significantly harm us. We face competition for these professionals from our competitors, our customers and other companies operating in our industry. To the extent that the services of

members of our senior management team and key technical personnel would be unavailable to us for any reason, we may be required to hire other personnel to manage and operate our company. We may not be able to locate or employ such qualified personnel on acceptable terms, or at all.

We are exposed to the credit risks of our key customers.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. If any of our key customers default on their obligations to us, our financial results could be adversely affected. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks.

Terrorist attacks, and the threat of terrorist attacks, have resulted in increased costs to our business. Continued hostilities in the Middle East or other sustained military campaigns may adversely impact our results of operations.

The long-term impacts of terrorist attacks, such as the attacks that occurred on September 11, 2001, and the threat of future terrorist attacks on the energy transportation industry in general, and on us in particular, are not known at this time. Increased security measures taken by us as a precaution against possible terrorist attacks have resulted in increased costs to our business. Uncertainty surrounding continued hostilities in the Middle East or other sustained military campaigns may affect our operations in unpredictable ways, including disruptions of crude oil supplies and markets for refined products, and the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror.

Item 1B. Unresolved Staff Comments

We do not have any unresolved staff comments.

Item 3. Legal Proceedings

We have pending proceedings in the United States Court of Appeals for the District of Columbia Circuit with respect to rulings by the Federal Energy Regulatory Commission (FERC) in proceedings brought by us and other parties against SFPP. These proceedings relate to tariffs of common carrier pipelines, which are owned and operated by SFPP, for shipments of refined products from El Paso, Texas to Tucson and Phoenix, Arizona and from points in California to points in Arizona. We are one of several refiners that regularly utilize an SFPP pipeline to ship refined products from El Paso, Texas to Tucson and Phoenix, Arizona. Rulings by the FERC relating principally to the period from 1993 through July 2000 resulted in reparations payments from SFPP to us in 2003 totaling approximately $15.3 million. In 2004 the appeals court issued its opinion relating principally to the period from 1993 through July 2000, ruling in favor of our positions on most of the disputed issues that concern us, and remanded the case to the FERC for additional consideration of several issues, some of which are involved in our claims. In May 2005, the FERC issued a general policy statement on an issue concerning the treatment of income taxes in the calculation of allowable rates for pipelines operated by partnerships. The FERC in a later order applied this general policy statement to SFPP and such application is contrary to our position in this case. We and certain other refining companies have pending before the court of appeals petitions challenging the FERC policy on income taxes, decisions by the FERC in 2005 and early 2006 on certain of the remanded issues, and rulings by the FERC on some issues relating to periods after July 2000. In March 2006, SFPP submitted computations asserted to be based on the most recent determinations of the FERC in the case. In April 2006, we filed a protest and comments concerning a number of elements of these computations. One element of the computations, which is based on the FERC s disputed 2005 policy on treatment of income taxes, would if ultimately sustained result in a requirement for us to repay to SFPP approximately $3.0 million of the $15.3 million reparations amount received by us from SFPP in 2003. Because proceedings in the FERC on remand have not been completed and our petitions for review to the court of appeals with respect to the FERC s orders are pending, it is not possible to determine whether the amount of reparations actually due to us for the period from 1993 through July 2000 will be found to be less than or more than the $15.3 million we received in 2003. Although it is not possible at the date of this report to predict the final outcome of these proceedings, we believe that future proceedings are not likely to result in an obligation for us to repay more than the amount now asserted in SFPP s most recent computations (approximately $3.0 million) and that the more likely final result would be either a smaller repayment by us than is now asserted by SFPP or a payment to us of additional reparations. The ultimate amount of reparations payable to us will be determined only after further proceedings in the FERC on issues that have not been finally determined by the FERC, further proceedings in the appeals court with respect to determinations by the FERC, and possibly future petitions by one or more of the parties seeking United States Supreme Court review of issues in the case.

We have pending in the United States Court of Federal Claims a lawsuit against the Department of Defense relating to claims totaling approximately $299.0 million with respect to jet fuel sales by two subsidiaries in the years 1982 through 1999. Our claims are similar to claims in a number of other cases that have also been pending in the United States Court of Federal Claims brought by other refining companies concerning military fuel sales. In response to our request, the judge in our case issued in February 2006 an order continuing the stay of our case originally ordered in March 2004. While the stay of our case is in effect we expect that further judicial proceedings in one or more other cases brought by other refining companies may clarify the legal standards that will apply to our case. In August and September 2006, three judges of the United States Court of Federal Claims issued rulings adverse to three other refining companies on issues that are also involved in our case. The refining companies that received these adverse rulings filed appeals of the adverse rulings to the United States Court of Appeals for the Federal Circuit in the fall of 2006. At the date of this report, it is not possible to predict the outcome of further proceedings with respect to our case.

In discussions beginning in the last half of 2005, the EPA and the State of Utah have asserted that we have Federal Clean Air Act liabilities relating to our Woods Cross Refinery because of actions taken or not taken by prior owners of the Woods Cross Refinery, which we purchased from ConocoPhillips in June 2003. We have tentatively agreed with the EPA and the State of Utah to settle the issues presented by means of an agreement similar to the 2001 Consent Agreement we entered into for our Navajo Refinery and previously-owned Montana Refinery. The tentative settlement agreement, which has not yet been put into a final written agreement, includes proposed obligations for us to make specified additional capital investments expected to total up to approximately $10.0 million over several years and to make changes in operating procedures at the refineries. The agreements for the purchase of the Woods Cross Refinery provide that ConocoPhillips will indemnify us, subject to specified limitations, for environmental claims arising from circumstances prior to our purchase of the refinery. We believe that, in the present circumstances, the amount due to us from ConocoPhillips under the agreements for the purchase of the Woods Cross Refinery would be approximately $1.4 million with respect to the tentative settlement.

Our Navajo Refining Company subsidiary is named as a defendant, along with approximately 40 other companies involved in oil refining and marketing and related businesses, in a lawsuit originally filed in May 2006 by the State of New Mexico in the U.S. District Court for the District of New Mexico. The lawsuit, as amended in October 2006 through the filing of a second amended complaint in the U.S. District Court for the Southern District of New York under multidistrict procedures, alleges that the defendants are liable for contaminating the waters of New Mexico through producing and/or supplying MTBE or gasoline or other products containing MTBE. The claims made are for defective design or product, failure to warn, negligence, public nuisance, statutory public nuisance, private nuisance, trespass, and civil conspiracy. The second amended complaint also contains a claim, which is asserted in the complaint only against certain other defendants but which appears to be similar to a claim that has been threatened in a mailing to Navajo by law firms representing the plaintiff in this case, alleging violations of certain provisions of the Toxic Substances Control Act. The lawsuit seeks compensatory damages unspecified in amount, injunctive relief, exemplary and punitive damages, costs, attorney s fees allowed by law, and interest allowed by law. As of the close of business on the day prior to the date of this report, Navajo has not been served in this case. At the date of this report, it is not possible to predict the likely course or outcome of this litigation.

On December 6, 2006, the Montana Department of Environmental Quality (MDEQ) filed in state district court in Great Falls, Montana a Complaint and Application for Preliminary Injunction (the Complaint) naming as defendants Montana Refining Company (MRC), our subsidiary that owned the Great Falls, Montana refinery until it was sold to an unrelated purchaser on March 31, 2006, and the unrelated company that purchased the refinery from MRC. The MDEQ asserts in the Complaint that the Great Falls refinery exceeded limitations on sulfur dioxide in the refinery s air emission permit on certain dates in 2004 and 2005 and in 2006 both before and after the sale of the refinery, erroneously certified compliance with limitations on sulfur dioxide emissions, failed to promptly report emissions limit deviations, exceeded limits on sulfur in fuel gas on specified dates in 2005, failed in 2005 to conduct timely testing for certain emissions, submitted late a report required to be submitted in early 2006, failed to achieve a specified limitation on certain emissions in the first three quarters of 2006, and failed to timely submit a report on a 2005 emissions test. The Complaint seeks penalties under applicable law of up to $10,000 per violation and an order enjoining MRC and the current owner of the refinery from further violations. While we do not agree with a number of the violations asserted in the Complaint, we and the current owner of the Great Falls refinery have been in negotiations with the MDEQ both before and after the filing of the Complaint to attempt to settle the issues raised on a compromise basis. At the date of this report, we are not able to predict the outcome of this matter.

We are a party to various other litigation and proceedings not mentioned in this report which we believe, based on advice of counsel, will not have a materially adverse impact on our financial condition, results of operations or cash flows.

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

No matter was submitted to a vote of security holders during the fourth quarter of 2006.

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PART II

Item 5. Market for the Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

On April 26, 2004, our stock began trading on the New York Stock Exchange under the trading symbol HOC . Our stock was formerly traded on the American Stock Exchange under the symbol HOC .

The following table sets forth the range of the daily high and low sales prices per share of common stock, dividends declared per share and the trading volume of common stock (adjusted for the two-for-one stock split effective June 1, 2006) for the periods indicated:

Years ended December 31,	High	Low	Dividends	Trading Volume
2006				
First Quarter	$37.92	$27.93	$0.05	47,232,600
Second Quarter	$48.20	$36.23	$0.08	68,210,900
Third Quarter	$55.96	$38.04	$0.08	77,970,800
Fourth Quarter	$56.44	$39.38	$0.08	52,161,800
2005				
First Quarter	$19.85	$12.64	$0.04	33,253,000
Second Quarter	$23.63	$16.23	$0.05	41,571,200
Third Quarter	$32.44	$22.78	$0.05	40,896,800
Fourth Quarter	$32.73	$24.87	$0.05	40,203,000

As of February 16, 2007, we had approximately 25,000 stockholders, including beneficial owners holding shares in street name.

We intend to consider the declaration of a dividend on a quarterly basis, although there is no assurance as to future dividends since they are dependent upon future earnings, capital requirements, our financial condition and other factors. The Credit Agreement limits the payment of dividends. See Note 11 in the Notes to Consolidated Financial Statements under Item 8, Financial Statements and Supplementary Data.

On October 30, 2006, we announced that our Board of Directors had authorized a $100 million increase to the $200 million common stock repurchase program announced on November 7, 2005. The increase raises the authorized repurchase limit under the common stock repurchase program from $200 million to $300 million. The following table includes repurchases made under this program during the fourth quarter of 2006.

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of $300 Million Program	Maximum Dollar Value of Shares Yet to be Purchased as Part of the $300 Million Program(1)
October 1 October 31	72,631	$ 41.34	72,631	$ 127,054,699
November 1 November 30	269,936	$ 51.90	269,936	$ 113,044,979
December 1 December 31	372,852	$ 53.68	372,852	$ 93,031,055
Total	715,419	$ 51.75	715,419	

(1) As a result of the board authorized increase on October 30, 2006, the stock repurchase plan balance increased by $100,000,000 raising the maximum dollar value available for stock repurchases from $27,054,699 to $127,054,699.

On February 9, 2007 our Board of Directors declared a regular quarterly cash dividend of $0.10 per share, payable April 3, 2007 to holders of record on March 22, 2007.

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Item 6. Selected Financial Data

The following table shows our selected financial information as of the dates or for the periods indicated. This table should be read in conjunction with Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements and related notes thereto included elsewhere in this Form 10-K.

	Years Ended December 31,				Five Months Ended December 31,	Fiscal Year Ended July 31,
	2006(1)	2005(1)(2)	2004(2)	2003(2)	2002(2)	2002(2)
	(In thousands, except per share data)					
FINANCIAL DATA						
For the period						
Sales and other revenues	$ 4,023,217	$ 3,046,313	$ 2,116,245	$ 1,302,699	$ 409,536	$ 805,152
Income from continuing operations before income taxes	383,501	263,652	136,929	74,211	9,729	48,599
Income tax provision	136,603	99,626	54,004	28,250	3,557	18,016
Income from continuing operations	246,898	164,026	82,925	45,961	6,172	30,583
Income from discontinued operations, net of taxes(3)	19,668	2,963	954	92	(769)	1,446
Net income before cumulative effect of change in accounting principle	266,566	166,989	83,879	46,053	5,403	32,029
Cumulative effect of accounting change (net of income tax expense of $426)		669				
Net income	$ 266,566	$ 167,658	$ 83,879	$ 46,053	$ 5,403	$ 32,029
Net income per common share basic	$ 4.68	$ 2.72	$ 1.34	$ 0.74	$ 0.09	$ 0.51
Net income per common share diluted	$ 4.58	$ 2.65	$ 1.30	$ 0.72	$ 0.08	$ 0.50
	$ 0.29	$ 0.19	$ 0.145	$ 0.11	$ 0.03	$ 0.10

Cash dividends declared per common share						
Average number of common Shares outstanding:						
Basic	56,976	61,728	62,780	62,020	62,064	62,240
Diluted	58,210	63,244	64,340	64,064	63,608	63,884
Net cash provided by (used for) operating activities	$ 245,183	$ 251,234	$ 164,604	$ 75,440	$ (8,209)	$ 53,951
Net cash provided by (used for) investing activities	$ 35,805	$ (320,135)	$ (194,003)	$ (122,714)	$ (25,293)	$ (33,603)
Net cash provided by (used for) financing activities	$ (175,935)	$ 50,505	$ 85,169	$ 34,698	$ (13,862)	$ (14,558)
At end of period						
Cash, cash equivalents and investments in marketable securities	$ 255,953	$ 254,842	$ 219,265	$ 11,690	$ 24,266	$ 71,630
Working capital	$ 247,459	$ 210,103	$ 159,839	$ (14,223)	$ 24,501	$ 72,105
Total assets	$ 1,237,869	$ 1,142,900	$ 982,713	$ 706,558	$ 515,793	$ 502,306
Total debt, including current maturities and borrowings under credit agreements	$	$	$ 33,572	$ 67,142	$ 25,714	$ 34,285
Stockholders equity	$ 466,094	$ 377,351	$ 339,916	$ 286,609	$ 228,494	$ 228,556

(1) We deconsolidated HEP effective July 1, 2005. The deconsolidation has been presented from July 1, 2005 forward, and our share of the earnings of HEP from July 1, 2005 is reported using the equity method of accounting.

(2)

The average number of shares of common stock and per share amounts have been adjusted to reflect the two-for-one stock split effective June 1, 2006.

(3) On March 31, 2006, we sold our Montana Refinery. Results of operations of the Montana Refinery that were previously reported in operations are now reported in discontinued operations.

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Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations

This Item 7 contains forward-looking statements. See Forward-Looking Statements at the beginning of this annual report on Form 10-K. In this document, the words we , our , ours and us refer only to Holly Corporation and its consolidated subsidiaries or to Holly Corporation or an individual subsidiary and not to any other person.

OVERVIEW

We are principally an independent petroleum refiner operating two refineries in Artesia and Lovington, New Mexico (operated as one refinery) and Woods Cross, Utah. Our profitability depends largely on the spread between market prices for refined petroleum products and crude oil prices. At December 31, 2006, we also owned a 45% interest in HEP, which owns and operates pipeline and terminalling assets and owns a 70% interest in Rio Grande.

Our principal source of revenue is from the sale of high value light products such as gasoline, diesel fuel and jet fuel in markets in the southwestern and western United States. Additionally, starting April 1, 2006, we began recording direct sales of crude oil as revenues with the related acquisition costs included in cost of products, as required by recent accounting guidance (see New Accounting Pronouncements under Critical Accounting Policies below for additional discussion on this new accounting guidance). Prior to April 1, 2006, sales and cost of sales attributable to such crude oil direct sales were netted and presented in cost of products sold. During the year ended December 31, 2006, we recorded crude oil sales under this new guidance of $323.0 million with a corresponding cost of $323.3 million. Our total sales and other revenues for the year ended December 31, 2006 were $4,023.2 million and our net income for the year ended December 31, 2006 was $266.6 million. Our sales and other revenues and net income for the year ended December 31, 2005 were $3,046.3 million and $167.7 million, respectively. Our principal expenses are costs of products sold and operating expenses. Our total operating costs and expenses for the year ended December 31, 2006 were $3,661.3 million, an increase from $2,783.6 million for the year ended December 31, 2005.

On March 31, 2006 we sold our Montana Refinery to Connacher. The net cash proceeds we received on the sale of the Montana Refinery amounted to $48.9 million, net of transaction fees and expenses. Additionally we received 1,000,000 shares of Connacher common stock valued at $4.3 million at March 31, 2006. Accordingly, the results of operations of the Montana Refinery and a gain on the sale of $14.0 million, net of income taxes of $8.3 million, are shown in discontinued operations.

On May 11, 2006, we announced that our Board of Directors had approved a two-for-one stock split payable in the form of a stock dividend of one share of common stock for each issued and outstanding share of common stock. The stock dividend was paid on June 1, 2006 to all holders of record of common stock at the close of business on May 22, 2006. All references to the number of shares of common stock (other than authorized shares and other than issued shares and treasury shares at December 31, 2005 shown on our Consolidated Balance Sheets) and per share amounts for all periods presented have been adjusted to reflect the split on a retrospective basis.

On October 30, 2006, we announced that our Board of Directors had authorized a $100.0 million increase in our $200.0 million common stock repurchase program announced in November 2005, increasing the authorized repurchase limit under the stock repurchase program from $200.0 million to $300.0 million. Repurchases are being made from time to time in the open market or privately negotiated transactions based on market conditions, securities law limitations and other factors. During the year ended December 31, 2006, we repurchased under this repurchase initiative 4,458,607 shares at a cost of $177.0 million (of which $3.0 million of the cash settlement was after December 31, 2006) or an average of $39.70 per share. Since inception of this repurchase initiative through December 31, 2006, we have repurchased 5,446,207 shares at a cost of $207.0 million or an average of $38.00 per share.

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RESULTS OF OPERATIONS
Financial Data

	Years Ended December 31,		
	2006	2005	2004
	(In thousands, except per share data)		
Sales and other revenues	$ 4,023,217	$ 3,046,313	$ 2,116,245
Operating costs and expenses:			
Cost of products sold (exclusive of depreciation, depletion and amortization)	3,349,404	2,498,810	1,728,545
Operating expenses (exclusive of depreciation, depletion and amortization)	208,460	192,051	154,884
General and administrative expenses (exclusive of depreciation, depletion and amortization)	63,255	51,683	50,693
Depreciation, depletion and amortization	39,721	40,547	37,457
Exploration expenses, including dry holes	486	481	689
Total operating costs and expenses	3,661,326	2,783,572	1,972,268
Income from operations	361,891	262,741	143,977
Other income (expense):			
Equity in loss of joint ventures		(685)	(318)
Equity in earnings of HEP	12,929	6,517	
Minority interests in income of partnerships		(6,721)	(7,575)
Interest income	9,757	6,901	4,369
Interest expense	(1,076)	(5,101)	(3,524)
	21,610	911	(7,048)
Income from continuing operations before income taxes	383,501	263,652	136,929
Income tax provision	136,603	99,626	53,985
Income from continuing operations	246,898	164,026	82,944
Income from discontinued operations, net of taxes	19,668	2,963	935
Net income before cumulative effect of change in accounting principle	266,566	166,989	83,879
Cumulative effect of accounting change (net of income tax expense of $426)		669	
Net income	$ 266,566	$ 167,658	$ 83,879
Basic earnings per share:			
Continuing operations	$ 4.33	$ 2.66	$ 1.32
Discontinued operations	0.35	0.05	0.02
Cumulative effect of accounting change		0.01	
Net income	$ 4.68	$ 2.72	$ 1.34

Diluted earnings per share:						
Continuing operations	$	4.24	$	2.59	$	1.29
Discontinued operations		0.34		0.05		0.01
Cumulative effect of accounting change				0.01		
Net income	$	4.58	$	2.65	$	1.30
Cash dividends declared per common share	$	0.29	$	0.19	$	0.145
Average number of common shares outstanding:						
Basic		56,976		61,728		62,780
Diluted		58,210		63,244		64,340

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Balance Sheet Data

	Years Ended December 31, 2006	2005
	(In thousands)	
Cash, cash equivalents and investments in marketable securities	$ 255,953	$ 254,842
Working capital	$ 247,459	$ 210,103
Total assets	$1,237,869	$1,142,900
Stockholders equity	$ 466,094	$ 377,351

Other Financial Data

	Years Ended December 31, 2006	2005	2004
		(In thousands)	
Net cash provided by operating activities	$ 245,183	$ 251,234	$ 164,604
Net cash provided by (used for) investing activities	$ 35,805	$(320,135)	$(194,003)
Net cash provided by (used for) financing activities	$(175,935)	$ 50,505	$ 85,169
Capital expenditures	$ 120,429	$ 106,262	$ 37,780
EBITDA from continuing operations [1]	$ 414,541	$ 302,399	$ 173,541

(1) Earnings before interest, taxes, depreciation and amortization, which we refer to as (EBITDA), is calculated as net income plus (i) interest expense net of interest income, (ii) income tax provision, and (iii) depreciation, depletion and amortization. EBITDA is not a calculation provided for under accounting principles generally accepted in the United States; however, the amounts included in the EBITDA calculation are derived from

amounts included in our consolidated financial statements. EBITDA should not be considered as an alternative to net income or operating income as an indication of our operating performance or as an alternative to operating cash flow as a measure of liquidity. EBITDA is not necessarily comparable to similarly titled measures of other companies. EBITDA is presented here because it is a widely used financial indicator used by investors and analysts to measure performance. EBITDA is also used by our management for internal analysis and as a basis for financial covenants. We are reporting EBITDA from continuing operations. EBITDA presented above is reconciled to net income under Reconciliations to Amounts Reported Under

Generally Accepted Accounting Principles following Item 7A of Part II of this Form 10-K.

Our sole reportable business segment is Refining after the deconsolidation of HEP effective July 1, 2005. From the closing of the initial public offering of HEP on July 13, 2004 until this deconsolidation, our segments reflected two business divisions, Refining and HEP. The Refining segment for the year ended December 31, 2004 includes the results of operations involving the assets included in HEP prior to the contribution on July 13, 2004. The HEP segment did not have any activity prior to HEP s formation on July 13, 2004 or subsequent to the deconsolidation effective July 1, 2005.

	Years Ended December 31,		
	2006	**2005**	**2004**
		(In thousands)	
Sales and other revenues [1]			
Refining	$ 4,021,974	$ 3,028,335	$ 2,104,569
HEP		36,034	28,182
Corporate and other	1,752	1,772	1,916
Consolidations and eliminations	(509)	(19,828)	(18,422)
Consolidated	$ 4,023,217	$ 3,046,313	$ 2,116,245
Income from operations [1]			
Refining	$ 425,474	$ 296,508	$ 173,904
HEP		16,019	12,980
Corporate and other	(63,583)	(49,786)	(42,907)
Consolidated	$ 361,891	$ 262,741	$ 143,977

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(1) The Refining segment involves the purchase and refining of crude oil and wholesale and branded marketing of refined products, such as gasoline, diesel fuel and jet fuel, and includes our Navajo Refinery and Woods Cross Refinery. Although we previously included the Montana Refinery in the Refining segment, the results from the Montana Refinery are now reported in discontinued operations and are not included in the above tables. The petroleum products produced by the Refining segment are marketed in Texas, New Mexico, Arizona, Utah, Wyoming, Montana, Idaho, Washington and northern Mexico. The

Refining segment also includes certain crude oil pipelines that we own and operate in conjunction with our refining operations as part of the supply networks of the refineries. The Refining segment also includes the equity in earnings from our 49% interest in NK Asphalt Partners prior to February 2005. In February 2005, we acquired the remaining 51% interest in our asphalt joint venture from the other partner; subsequent to the purchase, we include the operations of NK Asphalt Partners in our consolidated financial statements. NK Asphalt Partners, doing business as Holly Asphalt Company, manufactures and markets asphalt and asphalt products in Arizona, New Mexico, Texas and California. The cost of pipeline transportation and terminal services provided by HEP is included in the Refining segment. The HEP segment involved all of the operations of HEP, including approximately 1,300 miles (780 miles prior to the Alon asset acquisition) of pipeline assets principally in Texas, New Mexico and Oklahoma and refined product terminals in several Southwest and Rocky Mountain states. The HEP segment also included a 70% interest in Rio Grande which provides petroleum products transportation. Revenues from the HEP segment were earned through transactions with unaffiliated parties for pipeline transportation, rental and terminalling operations as well as revenues relating to pipeline transportation services provided for our refining operations and from its interest in Rio Grande. Our operations not included in the reportable segment or segments are included in corporate and other, which includes costs of Holly Corporation, the parent company, consisting primarily of general and administrative expenses and interest charges as well as a small-scale oil and gas exploration and production program. The consolidations and eliminations amount includes the elimination of the revenue associated with pipeline transportation services between us and HEP prior to July 1, 2005.

Refining Operating Data

Our refinery operations include the Navajo Refinery and the Woods Cross Refinery. The following tables set forth information, including non-GAAP performance measures about our consolidated refinery operations. The cost of products and refinery gross margin do not include the effect of depreciation, depletion and amortization.

Reconciliations to amounts reported under GAAP are provided under Reconciliations to Amounts Reported Under Generally Accepted Accounting Principles following Item 7A of Part II of this Form 10-K.

	Years Ended December 31,		
	2006	2005	2004
Consolidated (8)			
Crude charge (BPD) (1)	96,570	95,950	94,680
Refinery production (BPD) (2)	105,730	106,040	103,060
Sales of produced refined products (BPD)	105,090	106,500	102,400
Sales of refined products (BPD) (3)	119,870	117,110	110,570
Refinery utilization (4)	92.4%	95.0%	94.7%
Average per produced barrel (5)			
Net sales	$ 80.21	$ 69.12	$ 51.40
Cost of products (6)	64.43	56.50	42.20
Refinery gross margin	15.78	12.62	9.20
Refinery operating expenses (7)	4.83	4.11	3.37
Net operating margin	$ 10.95	$ 8.51	$ 5.83

(1) Crude charge represents the barrels per day of crude oil processed at the crude units at our refineries.

(2) Refinery production represents the barrels per day of refined products yielded from processing crude and other refinery feedstocks through the crude units and other conversion units at our refineries.

(3) Includes refined products purchased for resale.

(4) Represents crude charge divided by total crude capacity (BPSD).

(5) Represents average per barrel amount for produced refined products sold, which is a non-GAAP measure. Reconciliations to amounts reported under GAAP are provided under Reconciliations to Amounts Reported Under Generally Accepted Accounting Principles following Item 7A of Part II of this Form 10-K.

(6) Transportation costs billed by HEP are included in cost of products.

(7) Represents operating expenses of the refineries, exclusive of depreciation, depletion and amortization.

(8) The Montana Refinery was sold on March 31, 2006.

Amounts reported are for the Navajo and Woods Cross Refineries.

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Results of Operations Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Summary

Income from continuing operations for the year ended December 31, 2006 was $246.9 million ($4.24 per diluted share) compared to $164.0 million ($2.59 per diluted share) for the year ended December 31, 2005. Income from continuing operations for 2006 as compared to 2005 increased 51% or $82.9 million, principally due to the higher refined product margins experienced throughout much of 2006. Our 2006 earnings also benefited from higher valued refinery yields due to the December 2005 start-up of our ROSE unit, which converts a significant portion of lower value asphalt into high value transportation fuels and the production of all our diesel fuel at both refineries as higher priced Ultra Low Sulfur Diesel (ULSD) beginning in July 2006, upon completion of our ULSD capital projects. Furthermore, revenues for the year ended December 31, 2006 include sales of sulfur credits which were generated because our Navajo Refinery is producing gasoline with a substantially lower sulfur content than applicable EPA requirements. These favorable factors were partially offset by the effects of higher operating costs and expenses incurred throughout most of 2006. Refinery production levels from continuing operations were relatively flat for the year ended December 31, 2006 as compared to 2005 primarily due to the offset of reduced production levels during the implementation of our ULSD and expansion projects against higher post-expansion production levels during the latter half of the year. Company-wide refinery margins from continuing operations were $15.78 per produced barrel for the year ended December 31, 2006 compared to refinery margins of $12.62 per produced barrel for the year ended December 31, 2005.

Sales and Other Revenues

Sales and other revenues from continuing operations increased 32% from $3,046.3 million for the year ended December 31, 2005 to $4,023.2 million for the year ended December 31, 2006, due principally to higher refined product sales prices experienced throughout much of 2006 combined with the recording of direct sales of crude oil as revenues effective April 1, 2006. The average sales price we received per produced barrel sold increased 16% from $69.12 for the year ended December 31, 2005 to $80.21 for the year ended December 31, 2006. The increase in sales and other revenues for the year ended December 31, 2006 also includes $323.0 million of revenues attributable to certain direct crude oil sales that were previously netted against the corresponding purchases and presented in cost of products sold prior to our adoption of new accounting guidance effective April 1, 2006. Additionally, revenues increased by the sales of $15.9 million for sulfur credits generated because our Navajo Refinery is producing gasoline with a substantially lower sulfur content than applicable EPA requirements.

Cost of Products Sold

Cost of products sold increased 34% from $2,498.8 million in 2005 to $3,349.4 million in 2006 due principally to the higher costs of purchased crude oil and the inclusion of costs attributable to direct crude oil sales. The average price we paid per barrel of crude oil and feedstocks used in production and the transportation costs of moving the finished products to the market place increased 14% from $56.50 in 2005 to $64.43 in 2006. Also, cost of products sold for the year ended December 31, 2006 increased by $323.3 million due to the inclusion of costs attributable to certain excess crude oil sales that were previously netted against the corresponding revenues and included in cost of products sold prior to our adoption of new accounting guidance effective April 1, 2006.

We recognized $4.2 million and $3.0 million in income in 2006 and 2005, respectively, resulting from the liquidations of certain last-in, first-out (LIFO) inventory quantities that were carried at lower costs compared to current costs.

During 2005, we entered into hedges totaling 1,505,000 barrels covering forecasted diesel fuel sales from November 2005 to February 2006. The positions were liquidated in 2005 resulting in a gain of $3.2 million during 2005, which was recorded as a decrease in cost of products sold.

Refinery Gross Margin

Refining gross margin per produced barrel increased 25% from $12.62 in 2005 to $15.78 in 2006. Refinery gross margin does not include the effects of depreciation, depletion or amortization. See Reconciliations to Amounts Reported Under Generally Accepted Accounting Principles following Item 7A of Part II of this Form 10-K for a reconciliation to the income statements of prices of refined products sold and costs of products purchased.

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Operating Expenses

Operating expenses increased 9% from $192.1 million in 2005 to $208.5 million in 2006 due principally to higher utility costs throughout most of the year and refinery maintenance, partially offset by the exclusion of HEP s operating costs in 2006 due to the deconsolidation of HEP effective July 1, 2005.

General and Administrative Expenses

General and administrative expenses increased 22% from $51.7 million in 2005 to $63.3 million in 2006 due primarily to increased equity-based incentive compensation.

Depreciation, Depletion and Amortization Expenses

Depreciation, depletion and amortization decreased 2% from $40.5 million in 2005 to $39.7 million in 2006 due primarily to the exclusion of HEP s depreciation resulting from the deconsolidation of HEP, partially offset by an increase in depreciation arising from capitalized refinery improvement projects in 2006.

Equity in Earnings of HEP and Minority Interests

Our equity in earnings of HEP was $12.9 million and $6.5 million for the years ended December 31, 2006 and 2005, respectively. Prior to July 1, 2005, HEP was a consolidated subsidiary, with the then minority interest partners share of HEP s earnings reported as minority interest. Minority interests in income of HEP for the year ended December 31, 2005 reduced income by $6.7 million.

Equity in Earnings of Joint Ventures

There was no equity in earnings of joint ventures for the year ended December 31, 2006 as all previously owned interests in joint ventures have been consolidated in our financials or have been sold. Equity in earnings of joint ventures for the year ended December 31, 2005 was a loss of $0.7 million, reflecting our interest in the NK Asphalt joint venture prior to our acquisition of the other partner s interest.

Interest Income

Interest income for the year ended December 31, 2006 was $9.8 million compared to $6.9 million for the year ended December 31, 2005. The increase in interest income was principally due to the effects of a higher interest rate environment on increased internally generated cash throughout 2006.

Interest Expense

Interest expense was $1.1 million for the year ended December 31, 2006 as compared to $5.1 million for the year ended December 31, 2006. The decrease for 2006 as compared to 2005 was principally due to the exclusion of HEP s interest expense in 2006 due to the deconsolidation of HEP effective July 1, 2005.

Income Taxes

Income taxes increased 37% from $99.6 million in 2005 to $136.6 million in 2006 due to significantly higher pre-tax earnings in 2006 as compared to 2005, partially offset by a lower effective tax rate. The effective tax rate for 2006 was 35.6%, as compared to 37.8% for 2005. The reduction in the effective tax rate was primarily due to income tax credits available to small business refiners. The Company s effective tax rate decreased in 2006 as compared to 2005 primarily due to the impact of the American Jobs Creation Act of 2004, which provides tax incentives for small business refiners incurring costs to produce ultra low sulfur diesel fuel.

Discontinued Operations

Income from discontinued operations was $19.7 million for the year ended December 31, 2006 as compared to $3.0 million for the year ended December 31, 2005. Included in income for the year ended December 31, 2006 was the gain on the sale of the Montana Refinery of $14.0 million, net of $8.3 million in income taxes. The operations of the Montana Refinery generated $5.7 million of earnings in 2006 as compared to $3.0 million in 2005. The increase in earnings from discontinued operations was also due in part to the liquidation in 2006 of retained finished product inventories relating to the Montana Refinery that had been carried at lower costs as compared to current values.

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Results of Operations Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Summary

Income from continuing operations for the year ended December 31, 2005 was $164.0 million ($2.59 per diluted share) compared to $82.9 million ($1.29 diluted share) for the year ended December 31, 2004. Income from continuing operations for 2005, as compared to 2004 increased 98% or $81.1 million principally due to higher refined product margins experienced in 2005. Additionally impacting earnings favorably were increased refinery production volumes, offset by higher refinery operating costs and expenses. In 2004, we received 100% of the benefit of the refined product pipelines and terminals contributed to HEP prior to its initial public offering in July 2004, whereas from July 2004 through 2005, approximately half of the income from HEP s refined product pipelines and terminals was attributable to other owners. Overall refinery production levels from continuing operations increased 3% to a total production level of 106,040 BPD in 2005 due to increased production at both refineries. Company-wide refinery margins from continuing operations were $12.62 per barrel in 2005 compared to margins of $9.20 per barrel in 2004.

Sales and Other Revenues

Sales and other revenues increased 44% from $2,116.2 million in 2004 to $3,046.3 million in 2005 due principally to higher refined product sales prices, and to a lesser degree, increased volumes sold at our refineries. The average sales price we received per produced barrel sold increased 34% from $51.40 in 2004 to $69.12 in 2005. The total volume of refined products we sold increased 6% in 2005 as compared to 2004. Additionally impacting sales were increases in 2005 due to the inclusion of the NK Asphalt Partners joint venture in the 2005 consolidated financial statements following our February 2005 purchase of the other partner s interest, and the inclusion of revenues from HEP s assets acquired from Alon for the period March through June 2005.

Cost of Products Sold

Cost of products sold increased 45% from $1,728.5 million in 2004 to $2,498.8 million in 2005 due principally to higher costs of crude oil, and to a lesser degree, increased volumes sold. The average price we paid per barrel of crude oil purchased increased 34% from $42.20 in 2004 to $56.50 in 2005. Additionally impacting cost of sales were increases in 2005 due to the inclusion of the NK Asphalt Partners joint venture in the 2005 consolidated financial statements.

We recognized $3.0 million and $4.9 million in income in 2005 and 2004, respectively, resulting from the liquidations of certain last-in, first-out (LIFO) inventory quantities that were carried at lower costs compared to current costs.

During 2005, we entered into hedges totaling 1,505,000 barrels covering forecasted diesel fuel sales from November 2005 to February 2006. The positions were liquidated in 2005 resulting in a gain of $3.2 million, which was recorded as a decrease in cost of products sold.

Refinery Gross Margin

Refining gross margin per produced barrel increased 37% from $9.20 in 2004 to $12.62 in 2005. Refinery gross margin does not include the effects of depreciation, depletion or amortization. See Reconciliations to Amounts Reported Under Generally Accepted Accounting Principles following Item 7A of Part II of this Form 10-K for a reconciliation to the income statements of prices of refined products sold and costs of products purchased.

Operating Expenses

Operating expenses increased 24% from $154.9 million in 2004 to $192.1 million in 2005 due to the higher production levels, increased utility and catalyst costs, operating costs associated with the assets HEP acquired from Alon for the period March to June 2005 prior to the HEP deconsolidation and the inclusion of the NK Asphalt Partners joint venture in the 2005 consolidated financial statements, while reduced by the operating costs of HEP in the 2005 third and fourth quarters which are no longer consolidated in the Company s results. The increase in utility costs was mainly due to price increases during 2005 for purchased natural gas.

General and Administrative Expenses

General and administrative expenses increased 2% from $50.7 million in 2004 to $51.7 million in 2005 due primarily to an increase in non-share based incentive compensation, offset by a decrease in share-based compensation expense and reduced legal fees for 2005 as compared to 2004.

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Depreciation, Depletion and Amortization Expenses

Depreciation, depletion and amortization increased 8% from $37.5 million in 2004 to $40.5 million in 2005 due to depreciation on the assets HEP acquired from Alon for the period March to June 2005, the inclusion of the NK Asphalt Partners joint venture in the 2005 consolidated statements and increased depreciation and amortization on other capital assets placed in service in 2004 and 2005. These factors were partially offset by the absence of depreciation on HEP s assets for the third and fourth quarters of 2005 after the deconsolidation of HEP effective July 1, 2005.

Equity in Earnings of HEP

As part of the deconsolidation of HEP effective July 1, 2005, we now show equity in earnings in HEP for our ownership percentage of HEP, currently 45.0%, including any incentive distributions paid with respect to our general partner interest. Equity in earnings of HEP in 2005 was $6.5 million, which represents our 45.0% of HEP s earnings for the last six months of 2005. There was no equity in earnings of HEP for 2004 as HEP was a consolidated subsidiary from its commencement of operations.

Equity in Earnings of Joint Ventures and Minority Interests

Equity in earnings of joint ventures in 2005 included a loss of $0.7 million from our interest in NK Asphalt Partners joint venture for the period prior to the increase in our ownership to 100% in February 2005. Minority interests in income of partnerships in 2005 was a reduction in income of $6.7 million which represented the minority interest partners 52.1% ownership share of HEP s income prior to July 2005 (49% prior to HEP s asset acquisition from Alon on February 28, 2005). As of July 1, 2005, minority interests are no longer being recognized due to the deconsolidation of HEP. Equity in earnings of joint ventures in 2004 included a loss of $0.1 million from our interest in NK Asphalt Partners joint venture. Minority interests in income of partnerships in 2004 resulted in a reduction of income of $7.6 million. This represented the minority interest partners 49% ownership of HEP (subsequent to HEP s July 2004 initial public offering) and the minority owner s 30% ownership share of the Rio Grande joint venture s income (prior to HEP s initial public offering).

Interest Income

Interest income for 2005 was $6.9 million compared to $4.4 million for 2004. Interest income in 2005 represents interest earned on our investible funds resulting from the receipt of proceeds from the initial public offering of HEP, sale of intermediate pipelines to HEP and internally generated cash flows. The interest income in 2004 resulted from the $2.2 million accrued interest received with $25.0 million of principal from Longhorn Partners Pipeline, L.P. on July 1, 2004 and the interest earned on the proceeds from the initial public offering of HEP in July 2004.

Interest Expense

Interest expense was $5.1 million for 2005 as compared to $3.5 million for 2004. The increase for 2005 as compared to 2004 was principally due to higher interest costs associated with the 6.25% senior notes of HEP due 2015 (HEP Senior Notes) through June 30, 2005 prior to deconsolidation.

Income Taxes

Income taxes increased 84% from $54.0 million in 2004 to $99.6 million in 2005 due principally to the higher earnings during 2005 as compared to 2004. The effective tax rate for 2005 was 37.8%, as compared to 39.4% for 2004. Our effective tax rate decreased in 2005 as compared to 2004 primarily due to the impact of the domestic production activities deduction enacted under the American Jobs Creation Act of 2004. In 2005, the current tax provision increased approximately $15.0 million due to the tax gain associated with the acquisition by HEP of the intermediate feedstock pipelines, an amount which was partially offset by the approximately $10.0 million reduction in current tax resulting from the immediate deduction allowed for 75% of certain capital costs paid or incurred in complying with the ULSD standards. The high current tax provision in 2004 reflects approximately $26.0 million associated with the tax gain on assets contributed upon the formation of HEP in July 2004.

Cumulative Effect of Accounting Change

With the adoption of Statement of Financial Accounting Standards (SFAS) No. 123 (revised), we recorded a cumulative effect of a change in accounting principle in 2005 relating to our performance units, due to the initial effect of measuring these awards at fair value, where previously they were measured at intrinsic value. The total cumulative effect of this change in accounting principle recorded upon adoption was a gain of approximately

$0.7 million, net of approximately $0.4 million of deferred tax expense.

Discontinued Operations

Income from discontinued operations was $3.0 million for the year ended December 31, 2005 as compared to $0.9 million for the year ended December 31, 2004. During 2005, the Montana Refinery realized higher refined product margins as well as increased volumes of refined products sold.

LIQUIDITY AND CAPITAL RESOURCES

We consider all highly-liquid instruments with a maturity of three months or less at the time of purchase to be cash equivalents. Cash equivalents are stated at cost, which approximates market value, and are invested primarily in conservative, highly-rated instruments issued by financial institutions or government entities with strong credit standings. We also invest available cash in highly-rated marketable debt securities primarily issued by government entities that have maturities greater than three months. These securities include investments in variable rate demand notes (VRDN) and auction rate securities (ARS). Although VRDN and ARS may have long-term stated maturities, generally 15 to 30 years, we have designated these securities as available-for-sale and have classified them as current because we view them as available to support our current operations. Rates on VRDN are typically reset either daily or weekly. Rates on ARS are reset through a Dutch auction process at intervals between 35 and 90 days, depending on the terms of the security. VRDN and ARS may be liquidated at par on the rate reset date. We also invest in other marketable debt securities with the maximum maturity of any individual issue not greater than two years from the date of purchase. All of these instruments are classified as available-for-sale, and as a result, are reported at fair value. Unrealized gains and losses, net of related income taxes, are reported as a component of accumulated other comprehensive income or loss. As of December 31, 2006, we had cash and cash equivalents of $154.1 million, marketable securities with maturities under one year of $96.2 million and marketable securities with maturities greater than one year, but less than two years, of $5.7 million.

Cash and cash equivalents increased by $105.1 million during 2006. The combined cash provided by operating activities and investing activities of $245.2 million and $35.8 million, respectively, exceeded cash used by financing activities of $175.9 million. Working capital increased during 2006 by $37.4 million.

On July 1, 2004, we entered into a $175.0 million secured revolving credit facility with Bank of America as administrative agent and a lender, with a term of four years and an option to increase it to $225.0 million subject to certain conditions. The credit facility may be used to fund working capital requirements, capital expenditures, acquisitions and other general corporate purposes. As of December 31, 2006, we had letters of credit outstanding under our revolving credit facility of $2.3 million and had no borrowings outstanding. We were in compliance with all covenants at December 31, 2006.

On October 30, 2006, we announced that our Board of Directors had authorized a $100.0 million increase to our $200.0 million common stock repurchase program increasing the authorized stock repurchase limit from $200.0 million to $300.0 million. During 2006, we repurchased 4,458,607 shares at a cost of $177.0 million or an average of $39.70 per share under this repurchase initiative. As of December 31, 2006, a total of 5,446,207 shares costing $207.0 million or an average of $38.00 per share had been repurchased under this initiative since its inception in November 2005.

We believe our current cash, cash equivalents and marketable securities, along with future internally generated cash flow and funds available under our credit facility provide sufficient resources to fund currently planned capital projects and our liquidity needs for the foreseeable future as well as allow us to continue payment of quarterly dividends and the repurchase of additional common stock under our common stock repurchase program. In addition, components of our growth strategy may include construction of new refinery processing units and the expansion of existing units at our facilities and selective acquisition of complementary assets for our refining operations intended to increase earnings and cash flow. Our ability to acquire complementary assets will be dependent upon several factors, including our ability to identify attractive acquisition candidates, consummate acquisitions on favorable terms, successfully integrate acquired assets and obtain financing to fund acquisitions and to support our growth and many other factors beyond our control.

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Since HEP is no longer consolidated in our financial statements effective July 1, 2005, we no longer include the accounts of HEP in our consolidated financial statements, and our share of the earnings of HEP is now reported using the equity method of accounting. Accordingly, the HEP Senior Notes are not recorded on our accompanying consolidated balance sheet at December 31, 2006. Navajo Pipeline Co., L.P., one of our subsidiaries, has agreed to indemnify HEP s general partner to the extent it makes any payment in satisfaction of $35.0 million of the principal amount of the HEP Senior Notes.

Cash Flows Operating Activities

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Net cash flows provided by operating activities were $245.2 million for 2006 compared to $251.2 million for 2005, a decrease of $6.0 million. Net income in 2006 was $266.6 million, an increase of $98.9 million from net income of $167.7 million for 2005. The non-cash items of depreciation and amortization, deferred taxes, minority interests, equity-based compensation and gain on sale of assets decreased by $15.5 million for the year ended December 31, 2006 from the year ended December 31, 2005. Distributions in excess of equity in earnings of Holly Energy Partners and joint ventures increased by $4.3 million for the year ended December 31, 2006 from the year ended December 31, 2005. Working capital items decreased cash flows by $48.2 million in 2006, as compared to an increase of $35.9 million in 2005. For 2006, accounts receivable and accounts payable decreased $12.1 million and $26.4 million, respectively, as compared to 2005 accounts receivable and accounts payable increases of $128.3 million and $143.3 million, respectively.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Net cash flows provided by operating activities were $251.2 million for 2005 compared to $164.6 million for 2004, an increase of $86.6 million. Net income for 2005 was $167.7 million, an increase of $83.8 million from net income of $83.9 million 2004. The non-cash items of depreciation and amortization, deferred taxes, minority interests and equity-based compensation increased by $20.8 million for the year ended December 31, 2005 from the year ended December 31, 2004. Distributions in excess of equity in earnings of Holly Energy Partners and joint ventures decreased by $1.7 million for the year ended December 31, 2005 from the year ended December 31, 2004. Working capital items increased cash flows by $35.9 million in 2005, as compared to an increase of $24.5 million in 2004. Changes in accounts receivable and accounts payable were the primary causes of the increase in cash flows from working capital items for 2005 as compared to 2004. For 2005, accounts receivable increased $128.3 million and accounts payable increased $143.3 million, as compared to 2004 when accounts receivable increased $97.4 million and accounts payable increased $99.0 million. These increases were principally due to increases in prices for refined products and crude oil. Additionally, positively impacting cash provided by operating activities in 2004 was the $25.0 million (excluding interest) returned to us by Longhorn Partners under a prepaid transportation agreement.

Cash Flows Investing Activities and Capital Projects

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Net cash flows provided by investing activities were $35.8 million for 2006 as compared to net cash flows used for investing activities of $320.1 million for 2005, an increase of $355.9 million. Cash expenditures for property, plant and equipment for 2006 totaled $120.4 million as compared to $106.3 million for 2005. Capital expenditures in 2006 related primarily to the completion of the ULSD / expansion projects at the Navajo Refinery and the ULSD project at the Woods Cross Refinery that were initiated in 2005. We received net cash proceeds of $48.9 million following the sale of the Montana Refinery to Connacher on March 31, 2006. We also invested $212.0 million in marketable securities and received proceeds of $319.3 million from sales and maturities of marketable securities during 2006. Most of the 2005 expenditures were for the ULSD / expansion projects at the Navajo Refinery, the ULSD project at the Woods Cross Refinery and an asphalt unit at the Navajo Refinery. On February 28, 2005, HEP closed on its Alon transaction which required $120.0 million in cash plus transaction costs of $1.9 million. Upon the deconsolidation of HEP, we no longer include the cash of HEP in our consolidated financial statements, and therefore the HEP cash balance at June 30, 2005 is shown as a use of cash. In February 2005, we purchased the 51% interest in NK Asphalt Partners owned by the other partner. The total purchase consideration for the 51%

interest, including expenses, was $21.8 million, less cash of $3.4 million which was recorded due to the consolidation of NK Asphalt Partners at the time of our acquisition of the remaining 51% interest. We also invested $322.0 million in marketable securities and received proceeds of $268.0 million from sales and maturities of marketable securities during 2005.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Net cash flows used for investing activities were $320.1 million for 2005 and $194.0 million for 2004, a net change of $126.1 million. Cash expenditures for property, plant and equipment for 2005 totaled $106.3 million as compared to $37.8 million for 2004. Most of the 2005 expenditures were for the ULSD / expansion projects at the Navajo Refinery, the ULSD project at the Woods Cross Refinery and an asphalt unit at the Navajo Refinery. On February 28, 2005, HEP closed on its Alon transaction which required $120.0 million in cash plus transaction costs of $1.9 million. Upon the deconsolidation of HEP, we no longer include the cash of HEP in our consolidated financial statements, and therefore the HEP cash balance at June 30, 2005 is shown as a use of cash. In February 2005, we purchased the 51% interest in NK Asphalt Partners owned by the other partner. The total purchase consideration for the 51% interest, including expenses, was $21.8 million, less cash of $3.4 million which was recorded due to the consolidation of NK Asphalt Partners at the time of our acquisition of the remaining 51% interest. We also invested $322.0 million in marketable securities and received proceeds of $268.0 million from sales and maturities of marketable securities during 2005. We also invested $271.7 million in marketable securities and received proceeds of $119.0 million from the sale or maturity of marketable securities during 2004. Also, in 2004, we invested $3.3 million in joint ventures.

Planned Capital Expenditures

Each year our Board of Directors approves in our annual capital budget capital projects that our management is authorized to undertake. Additionally, at times when conditions warrant or as new opportunities arise, other or special projects may be approved. The funds allocated for a particular capital project may be expended over a period of several years, depending on the time required to complete the project. Therefore, our planned capital expenditures for a given year consist of expenditures approved for capital projects included in the current year s capital budget as well as, in certain cases, expenditures approved for capital projects in capital budgets for prior years. Our total new capital budget for 2007 is approximately $42.1 million, not including the capital projects approved in prior years, and our expansion and feedstock flexibility projects at the Navajo and Woods Cross refineries, as described below. The 2007 capital budget is comprised of $24.7 million for refining improvement projects for the Navajo Refinery, $9.7 million for projects at the Woods Cross Refinery, $3.2 million for transportation projects, $0.5 million for marketing-related projects, $2.8 million for asphalt plant projects and $1.2 million for information technology and other miscellaneous projects.

As announced in December 2006, we will be installing at the Navajo Refinery a new 15,000 BPD hydrocracker and a new 28 mmscf hydrogen plant at a budgeted cost of approximately $125.0 million. The addition of these units is expected to increase liquid volume recovery, increase the refinery s capacity to process outside feedstocks, and increase yields of high valued products, as well as enabling the refinery to meet the EPA s new low sulfur gasoline specifications. The hydrocracker and hydrogen plant projects will provide improved heavy crude oil processing flexibility.

As announced in February 2007, we will be revamping an existing crude unit at the Navajo Refinery which will increase crude capacity at the Navajo Refinery to approximately 100,000 BPD. Additionally, our Board of Directors has approved a revamp of the refinery s second crude unit and a new solvent de-asphalter unit. The newly approved components combined with the components approved in December bring the total budgeted amount for this expansion and heavy crude oil processing project to $225.0 million. It is currently anticipated that the expansion portion of the overall project consisting of the initial crude unit revamp, the new hydrocracker and the new hydrogen plant will be completed and operational by the fourth quarter of 2008. The completion of the heavy crude oil processing portion of the overall project, including the second crude unit revamp and the installation of the new solvent de-asphalter, will be targeted to coincide with development of future pipeline access to the Navajo Refinery for heavy Canadian crude oil and other foreign heavy crude oils transported from the Cushing, Oklahoma area. We plan to explore with HEP the most economical manner to obtain this needed pipeline access.

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Also at the Navajo Refinery, a project to install an additional 100 ton per day sulfur recovery unit included in the 2006 capital budget is currently underway at an estimated cost of $26.0 million. Approximately $2.0 million was spent on this project in 2006. This new sulfur recovery unit will permit our Navajo Refinery to process 100% sour crude and is planned for start-up in the third quarter of 2008. It is anticipated that the projects that will be completed by the fourth quarter of 2008 will also enable the Navajo Refinery, without significant additional investment, to comply with LSG specifications required by the end of 2010.

Also as announced in December 2006, we will be adding a at the Woods Cross Refinery new 15,000 BPD hydrocracker along with sulfur recovery and desalting equipment. The budgeted cost of these additions is approximately $100.0 million. These additions will expand the Woods Cross Refinery s crude processing capabilities from 26,000 BPD to 31,000 BPD while enabling the refinery to process up to 10,000 BPD of high-value low-priced black wax crude oil and up to 5,000 BPD of low-priced heavy Canadian crude oils. The Woods Cross Refinery expansion project as approved involves a higher capital investment than had originally been estimated, principally because of the substitution of a complex hydrocracker in place of certain desulfurization and expanded bottoms-processing modifications that had been included in preliminary planning. The substitution of the complex hydrocracker is expected to provide increased capabilities to process significantly more black wax crude oils, which have recently been priced at substantial discounts to West Texas Intermediate crude oil while yielding substantially higher value products than the discounted heavy Canadian crudes that were a more significant part of the original plan. These additions would also increase the refinery s capacity to process low-cost feedstocks and provide the necessary infrastructure for future expansions of crude oil refining capacity at the Woods Cross Refinery. The approved projects for the Woods Cross Refinery are expected to be completed during the fourth quarter of 2008.

In 2007 we expect to expend a total of approximately $179.0 million on currently approved capital projects, which amount consists of certain carryovers of capital projects from previous years, less carryovers to subsequent years of certain of the currently approved capital projects, combined with certain authorized expenditures for certain proposed major capital projects that are being evaluated.

In 2006 we completed our ULSD project and an expansion of the crude capacity at the Navajo Refinery. These projects included the expansion and conversion of the distillate hydrotreater to gas oil service, the conversion of the gas oil hydrotreater to ULSD service, the expansion of the continuous catalytic reformer, the expansion and conversion of the kerosene hydrotreater to naphtha service, the installation of additional sulfur recovery capacity, and the installation of a 10 mmscf per day hydrogen plant. The completion of these projects has allowed us to produce all of our diesel fuel as ULSD and has expanded our crude oil processing capabilities from 75,000 BPSD to 83,000 BPSD. The total cost of these projects was approximately $75.0 million, which was approved in the prior years capital budget. We plan to further increase crude capacity to 85,000 BPSD by the end of 2007 by relocating some heat exchangers and replacing some pumps in the Artesia crude unit at an estimated cost of $1.0 million.

Also in 2006, we completed a clean fuels project at the Woods Cross Refinery. The project included the construction of a diesel hydrotreater unit, at an approximate cost of $35.0 million, which was approved in prior years, and entered into a long-term hydrogen contract that has enabled the Woods Cross Refinery to produce ULSD.

To fully take advantage of the economics on the Woods Cross expansion project, additional crude pipeline capacity will be required to move Canadian crude to the Woods Cross Refinery. In February 2007, HEP entered into a letter of intent with Plains under which HEP will own a 25% interest in a new 95 mile intrastate pipeline system, now being constructed by Plains, capable of shipping up to 120,000 BPD of crude oil into the Salt Lake City area.

Additionally, we are also working with HEP to evaluate a refined products pipeline from Salt Lake City to Las Vegas. The current estimated cost of this pipeline is expected to be approximately $235.0 million, and the total cost of the project including terminals is expected to be approximately $300.0 million.

In October 2004, the American Jobs Creation Act of 2004 (2004 Act) was signed into law. Among other things, the 2004 Act creates tax incentives for small business refiners incurring costs to produce ULSD. The 2004 Act provides an immediate deduction of 75% of certain costs paid or incurred to comply with the ULSD standards, and a tax credit based on ULSD production of up to 25% of those costs. We estimate the tax savings that we derive from planned capital expenditures associated with the 2004 Act will result in a reduction in our income tax expense of approximately $10.0 million in 2007, representing the difference between the value of allowed credits under the 2004

Act as compared to the value of depreciating the investments. In August 2005, the Energy Policy Act of 2005

(2005 Act) was signed into law. Among other things, the 2005 Act creates tax incentives for refiners by providing for an immediate deduction of 50% of certain refinery capacity expansion costs when the expansion assets are placed in service. We believe the capacity expansions under the new Navajo and Woods Cross capital projects will qualify for this deduction.

The above mentioned regulatory compliance items, including the ULSD and LSG requirements, or other presently existing or future environmental regulations could cause us to make additional capital investments beyond those described above and incur additional operating costs to meet applicable requirements.

Cash Flows Financing Activities

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Net cash flows used by financing activities were $175.9 million for 2006, as compared to net cash flows provided by financing activities of $50.5 million for 2005, a decrease of $226.4 million. Under our $300.0 million stock repurchase program, we purchased treasury stock of $175.4 million in 2006. We also paid $15.0 million in dividends, received $2.6 million for common stock issued upon exercise of stock options and recognized $11.8 million in excess tax benefits on our equity based compensation during 2006. Our 2005 financing activities include the activities of HEP prior to our deconsolidation of HEP effective July 1, 2005. In connection with HEP s Alon asset acquisition on February 28, 2005, HEP received proceeds of $147.4 million from the issuance of HEP Senior Notes. In connection with HEP s purchase of our intermediate lines, HEP received proceeds of $34.6 million from additional issuance of their HEP Senior Notes, and raised $43.8 million, net of offering costs, from the private sale of 1.1 million of its common units to a limited number of institutional investors, which closed simultaneously with the acquisition. Additionally during 2005, we made our final scheduled repayment of long-term debt of $8.6 million, paid $11.2 million in dividends, received $2.8 million for common stock issued upon exercise of stock options, made distributions of $1.6 million to the minority interest partner of Rio Grande, made distributions of $7.9 million to the minority interests holders of HEP, paid down borrowings under HEP s credit facility netting to $25.0 million, incurred $0.9 million of debt issuance costs related to HEP s senior debt and recognized $6.0 million in excess tax benefits on our equity based compensation. Under our $200.0 million stock repurchase program, we purchased treasury stock of $30.0 million and under our $100.0 million stock repurchase program, we purchased treasury stock of $100.0 million. Also, during 2005, we repurchased at current market price from certain executives 24,790 shares of our common stock at a cost of approximately $0.8 million; these purchases were made under the terms of restricted stock agreements to provide funds for the payment of payroll and income taxes due at the vesting of restricted shares in the case of executives who did not elect to satisfy such taxes by other means.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Net cash flows provided by financing activities were $50.5 million for 2005, as compared to $85.2 million for 2004, a decrease of $34.7 million. In connection with HEP s Alon asset acquisition on February 28, 2005, HEP received proceeds of $147.4 million from the issuance of HEP Senior Notes. In connection with HEP s purchase of our intermediate lines, HEP received proceeds of $34.6 million from additional issuance of their HEP Senior Notes, and raised $43.8 million, net of offering costs, from the private sale of 1.1 million of its common units to a limited number of institutional investors, which closed simultaneously with the acquisition. Additionally during 2005, we made our final scheduled repayment of long-term debt of $8.6 million, paid $11.2 million in dividends, received $2.8 million for common stock issued upon exercise of stock options, made distributions of $1.6 million to the minority interest partner of Rio Grande, made distributions of $7.9 million to the minority interests holders of HEP, paid down borrowings under HEP s credit facility netting to $25.0 million, incurred $0.9 million of debt issuance costs related to HEP s senior debt and recognized $6.0 million in excess tax benefits on our equity based compensation. Under our $200.0 million stock repurchase program, we purchased treasury stock of $30.0 million and under our $100.0 million stock repurchase program, we purchased treasury stock of $100.0 million. Also, during 2005, we repurchased at current market price from certain executives 24,790 shares of our common stock at a cost of approximately $0.8 million; these purchases were made under the terms of restricted stock agreements to provide funds for the payment of payroll and income taxes due at the vesting of restricted shares in the case of executives who did not elect to satisfy such taxes by other means. In 2004, we received $142.0 million in net proceeds from the HEP initial public offering. During 2004 we repaid in full our borrowings under our credit facility of $50.0 million, and during 2004

HEP borrowed $25.0 million under their credit facility. Additionally,

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during 2004, we made a scheduled repayment of long-term debt of $8.6 million, paid $8.3 million in dividends, repurchased treasury stock for $15.3 million, received $4.7 million for common stock issued upon the exercise of options, made distributions of $3.2 million to the minority interest partner of Rio Grande, incurred debt issuance costs of $3.6 million related to our credit facility and HEP s financing, made distributions of $3.1 million to the minority interest holders of HEP and recognized $5.6 million in excess tax benefits on our equity based compensation.

Contractual Obligations and Commitments

The following table presents our long-term contractual obligations as of December 31, 2006 in total and by period due beginning in 2007. The table below does not reflect renewal options on our operating leases that are likely to be exercised.

		Payments Due by Period			
Contractual Obligations	**Total**	**Less than 1 Year**	**2-3 Years**	**4-5 Years**	**Over 5 Years**
			(In thousands)		
Operating leases	$ 10,452	$ 3,072	$ 4,275	$ 2,821	$ 284
Minimum revenue agreements with HEP [1]	$648,182	$50,863	$101,725	$101,725	$393,869
Hydrogen supply agreement[2]	$118,866	$	$	$ 15,849	$103,017
Other service agreements[3]	$ 18,761	$ 2,390	$ 4,752	$ 3,970	$ 7,649

(1) In connection with the initial public offering of HEP, we entered into a 15-year pipelines and terminals agreement with HEP under which we agreed generally to transport or terminal volumes on certain of HEP s initial facilities that will result in minimum annual payments to HEP, currently $38.5 million, that will adjust upward each year based on the percentage change in the producer price

index. Additionally in connection with HEP s purchase of our intermediate pipelines in July 2005, we entered into a 15-year pipelines agreement with HEP under which we agreed to transport a minimum annual volume commitment of 72,000 BPD on the pipelines that will result in minimum annual payments to HEP, currently $12.4 million, that will also adjust upward each year based on the percentage change in the producer price index.

(2) We have entered into a long-term supply agreement to secure a hydrogen supply source for our Woods Cross hydrotreater unit. The contract commits us to purchase a minimum of 5

million standard cubic feet of hydrogen per day at market prices over a fifteen year period commencing on a date at our discretion prior to December 31, 2009. The contract also requires the payment of a base facility charge for use of the supplier s facility over the supply term. We expect to initiate the supply term start date at the end of 2008. We have estimated the future payments in the table above using current market rates. Therefore, actual amounts expended for this obligation in the future could vary significantly from the amounts presented above.

(3) Includes $17.2 million for transportation of natural gas and feedstocks to our refineries under contracts expiring in 2015

and 2016 and
various service
contracts with
expiration dates
through 2011.

HEP financed the Alon transaction through a private offering of $150.0 million principal amount of HEP Senior Notes. HEP increased these notes to $185.0 million as part of the purchase of our intermediate pipelines. The $185.0 million HEP Senior Notes are not recorded on our accompanying consolidated balance sheet at December 31, 2006 due to the deconsolidation of HEP effective July 1, 2005. The HEP Senior Notes were reflected on our consolidated balance sheet (because HEP was a consolidated subsidiary) through June 30, 2005. Navajo Pipeline Co., L.P., one of our subsidiaries, has agreed to indemnify HEP s general partner to the extent it makes any payment in satisfaction of $35.0 million of the principal amount of the HEP Senior Notes.

In December 2001, we entered into an agreement for a Consent Decree (Consent Agreement) with the EPA and the New Mexico Environment Department of Environmental Quality with respect to a global settlement of issues concerning the application of air quality requirements to past and future operations of our refineries. The Consent

Agreement requires us to make investments at our New Mexico refinery for the installation of certain state of the art pollution control equipment currently expected to total approximately $14.0 million over a period expected to end in 2010, of which approximately $13.1 million has been expended to date.

Under the March 31, 2005 Asset Purchase Agreement entered into with Connacher s subsidiary by our subsidiaries MRC, Black Eagle, Inc. and Navajo Northern, Inc., whose obligations we guaranteed, we retained certain financial liabilities, including certain environmental liabilities related to required remediation and corrective action for environmental conditions that existed at the time of sale and for financial penalties for infractions that occurred prior to the sale. Our agreement provides that environmental claims must be made within 5 years of the sale and provides for a maximum liability of $41 million for any matter other than fraud and a deductible of $400,000. In addition, we have continuing obligations with respect to assets that were not transferred in our sale of the refinery. Based on our estimates, we recorded a liability of $2.2 million for such environmental liabilities.

CRITICAL ACCOUNTING POLICIES

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities as of the date of the financial statements. Actual results may differ from these estimates under different assumptions or conditions. We consider the following policies to be the most critical to understanding the judgments that are involved and the uncertainties that could impact our results of operations, financial condition and cash flows. For additional information, see Note 1 to the Consolidated Financial Statements Description of Business and Summary of Significant Accounting Policies.

Inventory Valuation

Our crude oil and refined product inventories are stated at the lower of cost or market. Cost is determined using the LIFO inventory valuation methodology and market is determined using current estimated selling prices. Under the LIFO method, the most recently incurred costs are charged to cost of sales and inventories are valued at the earliest acquisition costs. In periods of rapidly declining prices, LIFO inventories may have to be written down to market due to the higher costs assigned to LIFO layers in prior periods. In addition, the use of the LIFO inventory method may result in increases or decreases to cost of sales in years such as 2006 when inventory volumes decline and result in charging cost of sales with LIFO inventory costs generated in prior periods. As of December 31, 2006, our LIFO inventory layers were valued at historical costs that were established in years when price levels were much lower; therefore, our results of operation are less sensitive to current market price reductions. As of December 31, 2006, the excess of current cost over the LIFO inventory value of our crude oil and refined product inventories was approximately $136.6 million. An actual valuation of inventory under the LIFO method can be made only at the end of each year based on the inventory levels and costs at that time. Accordingly, interim LIFO calculations are based on management s estimates of expected year-end inventory levels and costs and are subject to the final year-end LIFO inventory valuation.

Deferred Maintenance Costs

Our refinery units require regular major maintenance and repairs which are commonly referred to as turnarounds. Catalysts used in certain refinery processes also require routine change-outs. The required frequency of the maintenance varies by unit and by catalyst, but generally is every two to five years. In order to minimize downtime during turnarounds, we utilize contract labor as well as our maintenance personnel on a continuous 24 hour basis. Whenever possible, turnarounds are scheduled so that some units continue to operate while others are down for maintenance. We record the costs of turnarounds as deferred charges and amortize the deferred costs over the expected periods of benefit.

Long-lived Assets

We calculate depreciation and amortization based on estimated useful lives and salvage values of our assets. When assets are placed into service, we make estimates with respect to their useful lives that we believe are reasonable. However, factors such as competition, regulation or environmental matters could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization. We evaluate long-lived assets for potential

impairment by identifying whether indicators of impairment exist and, if so, assessing whether the long-lived assets are recoverable from estimated future undiscounted cash flows. The actual amount of impairment loss, if any, to be recorded is equal to the amount by which a long-lived asset s carrying value exceeds its fair value. Estimates of future discounted cash flows and fair values of assets require subjective assumptions with regard to future operating results and actual results could differ from those estimates. No impairments of long-lived assets were recorded during the years ended December 31, 2006, 2005 and 2004.

Investment in HEP

In January 2003, FASB issued FIN 46 (revised December 2003), which we adopted effective December 31, 2003. This interpretation defined a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk or a controlling financial interest in the entity, or have voting rights that are not proportionate to their economic interests. This standard requires a company to consolidate a VIE if it is allocated a majority of the entity s expected losses or expected residual returns. Through June 30, 2005, our financial statements included the consolidated results of HEP, with the interest we did not own as a minority interest in the ownership and earnings. HEP is a VIE as defined under FIN 46, and following HEP s acquisition of the intermediate feedstock pipelines, we have determined that our beneficial variable interest in HEP is now less than 50%; and therefore as required by FIN 46, we have deconsolidated HEP effective as of July 1, 2005. The deconsolidation is being presented from July 1, 2005 forward, and our share of the earnings of HEP, including any incentive distributions paid through our general partner interest, is now reported using the equity method of accounting. HEP has risk associated with its operations. HEP has three major customers, one being us. If any of the customers fails to meet the desired shipping levels or terminates its contracts, HEP could suffer substantial losses unless a new customer is found. If HEP does suffer losses, we would recognize our percentage of those losses based on our ownership percentage at that time.

Contingencies

We are subject to proceedings, lawsuits and other claims related to environmental, labor, product and other matters. We are required to assess the likelihood of any adverse judgments or outcomes to these matters as well as potential ranges of probable losses. A determination of the amount of reserves required, if any, for these contingencies is made after careful analysis of each individual issue. The required reserves may change in the future due to new developments in each matter or changes in approach such as a change in settlement strategy in dealing with these matters.

New Accounting Pronouncements

EITF No. 04-13 Accounting for Purchases and Sales of Inventory with the Same Counterparty

The Emerging Issues Task Force reached a consensus on Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty, and the FASB ratified it in September 2005. This standard addresses accounting matters that arise when one company both sells inventory to and buys inventory from another company in the same line of business, specifically, when it is appropriate to measure purchases and sales of inventory at fair value and record them in cost of sales and revenues and when purchases and sales should be recorded as an exchange measured at the book value of the item sold. The consensus in this standard is to be applied to new arrangements entered into in reporting periods beginning after March 15, 2006. We adopted this standard effective April 1, 2006 and no longer account for certain crude oil transactions on a net basis.

In contemplation of the adoption of EITF 04-13, we modified our accounting procedures to identify the sale of crude oil determined to be in excess of our refinery requirements. These sales and related purchases are accounted for prospectively from April 1, 2006, as revenues with the related acquisition costs included in cost of products sold. Prior to the adoption of EITF 04-13, sales and cost of sales attributable to such excess crude oil sales were netted and presented in cost of products sold as amounts were not directly identified in our accounting systems and we believe they are immaterial to the presentation of our consolidated statements of income. For the year ended December 31, 2006, these crude oil sales amounted to $323.0 million with corresponding costs of $323.3 million.

Interpretation No. 48 Accounting for Uncertainty in Income Taxes

In June 2006, the FASB issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes. This interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements by prescribing a recognition threshold and measurement attribute for the financial statement recognition

and measurement of a tax position taken or expected to be taken in a tax return. This interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. This interpretation is effective for fiscal years beginning after December 15, 2006. We will adopt this interpretation effective for our 2007 fiscal year. We do not anticipate that the adoption of this standard will have a material effect on our financial condition, results of operations and cash flows.

SFAS No. 157 Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This standard simplifies and codifies guidance on fair value measurements under generally accepted accounting principles. This standard defines fair value, establishes a framework for measuring fair value and prescribes expanded disclosures about fair value measurements. This standard is effective for fiscal years beginning after November 15, 2007. We do not anticipate that the adoption of this interpretation will have a material effect on our financial condition, results of operations and cash flows.

SFAS No. 158 Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an Amendment of FASB Statements No. 87, 88, 106, and 132(R)

In September 2006, the FASB issued SFAS No. 158, Employer s Accounting for Defined Benefit Pension and Other Postretirement Plans, an Amendment of FASB Statements no. 87, 88, 106 and 132(R). This amendment requires an employer to recognize the funded status of a defined benefit postretirement plan as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. This standard also requires an employer to measure the funded status of a plan as of the date of its year-end financial statements. This standard is effective for fiscal years ending after December 15, 2006. We adopted this standard effective December 31, 2006 which resulted in the recognition of a net unrealized actuarial loss and prior service costs totaling $15.4 million as a component of accumulated other comprehensive loss. See Note 14 in the Notes to Consolidated Financial Statements under Item 8, Financial Statements and Supplementary Data for additional information regarding the adoption of SFAS No. 158.

RISK MANAGEMENT

We use certain strategies to reduce some commodity price and operational risks. We do not attempt to eliminate all market risk exposures when we believe the exposure relating to such risk would not be significant to our future earnings, financial position, capital resources or liquidity or that the cost of eliminating the exposure would outweigh the benefit. Our profitability depends largely on the spread between market prices for refined products and market prices for crude oil. A substantial or prolonged reduction in this spread could have a significant negative effect on our earnings, financial condition and cash flows.

We periodically utilize petroleum commodity futures contracts to reduce our exposure to price fluctuations associated with crude oil and refined products. Such contracts historically have been used principally to help manage the price risk inherent in purchasing crude oil in advance of the delivery date and as a hedge for fixed-price sales contracts of refined products. We have also utilized commodity price swaps and collar options to help manage the exposure to price volatility relating to forecasted purchases of natural gas. We regularly utilize contracts that provide for the purchase of crude oil and other feedstocks and for the sale of refined products. Certain of these contracts may meet the definition of a derivative instrument in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. We believe these contracts qualify for the normal purchases and normal sales exception under SFAS No. 133, because deliveries under the contracts will be in quantities expected to be used or sold over a reasonable period of time in the normal course of business. Accordingly, these contracts are designated as normal purchases and normal sales contracts and are not required to be recorded as derivative instruments under SFAS No. 133.

During 2005, we entered into two different types of hedging transactions, neither of which involved arrangements designated as hedging instruments per the requirements of SFAS No. 133, and therefore all gains and losses were recorded as incurred. The first transaction was entered into in July 2005 and related to our forecasted August 2005 liquidation of 100,000 barrels of crude oil at our Woods Cross Refinery, where our objective was to fix the price of crude oil associated with the liquidation. To affect the hedge, we sold crude oil futures contracts in July 2005 and liquidated the positions in August 2005 matching when the crude oil inventory was slated for production. We

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recognized a loss of $0.5 million on this transaction and recorded it as an increase in cost of products sold. The other type of transaction we have entered into from time to time starting in July 2005 relates to forecasted sales of diesel fuel from our refineries, where our principal objective is to take advantage of the higher margins (or crack spreads, being the difference between the price of diesel fuel and the cost of crude oil) on a portion of our diesel fuel sales. To effect these hedges, we sold heating oil futures (which most closely match diesel fuel pricing) and bought crude oil futures. We have also entered into commodity swap transactions (the terms of which mirror the futures contracts entered into) to effect the same strategy on a portion of these hedges. Our objective is either to liquidate the positions as the crack spreads return to more normalized levels, or to hold these positions until the forecasted diesel fuel sales are made, effectively locking in the diesel fuel crack spreads (or margins) at the high levels. Our strategy is to enter into these transactions only when the margins are at historically very high levels, and to have no more than 25% of our diesel fuel production hedged at any given time. During 2005, we entered into hedges totaling 1,505,000 barrels covering forecasted diesel fuel sales from November 2005 to February 2006. The positions were fully liquidated during August to November 2005 resulting in a realized gain of $3.2 million, which was recorded as a decrease in cost of products sold.

In October 2003, we entered into price swaps to help manage the exposure to price volatility relating to forecasted purchases of natural gas from December 2003 to March 2004. These transactions were designated as cash flow hedges of forecasted purchases. The contracts to hedge natural gas costs were for 6,000 MMBtu, 500 MMBtu, and 2,000 MMBtu per day for the Navajo Refinery, Montana Refinery, and the Woods Cross Refinery, respectively. The January to March 2004 contracts resulted in net realized gains of $0.3 million and were recorded as a reduction to refinery operating expenses. There was no ineffective portion of these hedges, and since March 31, 2004, no price swaps have been outstanding.

At December 31, 2006, we had no outstanding debt. As the interest rates on our bank borrowings are reset frequently based on either the bank s daily effective prime rate, or the LIBOR rate, interest rate market risk on any bank borrowings would be very low. At times, we have used borrowings under our credit facility to finance our working capital needs. There were no borrowings under the credit facilities at December 31, 2006. Before July 2004, we invested any available cash only in investment grade, highly liquid investments with maturities of three months or less and hence the interest rate market risk implicit in these cash investments was low. Beginning in July 2004, we are also investing certain available cash in portfolios of highly rated marketable debt securities, primarily issued by government entities, that have an average remaining duration (including any cash equivalents invested) of not greater than one year and hence the interest rate market risk implicit in these investments is also low. A hypothetical 10% change in the market interest rate over the next year would not materially impact our earnings, cash flow or financial condition since any borrowings under the credit facilities and investments are at market rates and such interest has historically not been significant as compared to our total operations.

Our operations are subject to normal hazards of operations, including fire, explosion and weather-related perils. We maintain various insurance coverages, including business interruption insurance, subject to certain deductibles. We are not fully insured against certain risks because such risks are not fully insurable, coverage is unavailable, or premium costs, in our judgment, do not justify such expenditures.

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Item 7A. Quantitative and Qualitative Disclosures About Market Risk

See Risk Management under Management s Discussion and Analysis of Financial Condition and Results of Operations.

Reconciliations to Amounts Reported Under Generally Accepted Accounting Principles

Reconciliations of earnings before interest, taxes, depreciation and amortization (EBITDA) to amounts reported under generally accepted accounting principles in financial statements.

Earnings before interest, taxes, depreciation and amortization, which we refer to as EBITDA, is calculated as net income plus (i) interest expense net of interest income, (ii) income tax provision, and (iii) depreciation, depletion and amortization. EBITDA is not a calculation provided for under accounting principles generally accepted in the United States; however, the amounts included in the EBITDA calculation are derived from amounts included in our consolidated financial statements. EBITDA should not be considered as an alternative to net income or operating income as an indication of our operating performance or as an alternative to operating cash flow as a measure of liquidity. EBITDA is not necessarily comparable to similarly titled measures of other companies. EBITDA is presented here because it is a widely used financial indicator used by investors and analysts to measure performance. EBITDA is also used by our management for internal analysis and as a basis for financial covenants. We are reporting EBITDA only from continuing operations.

Set forth below is our calculation of EBITDA from continuing operations.

	Years Ended December 31,		
	2006	**2005**	**2004**
		(In thousands)	
Income from continuing operations	$ 246,898	$ 164,026	$ 82,925
Add provision for income tax	136,603	99,626	54,004
Add interest expense	1,076	5,101	3,524
Subtract interest income	(9,757)	(6,901)	(4,369)
Add depreciation, depletion and amortization	39,721	40,547	37,457
EBITDA from continuing operations	$ 414,541	$ 302,399	$ 173,541

Reconciliations of refinery operating information (non-GAAP performance measures) to amounts reported under generally accepted accounting principles in financial statements.

Refinery gross margin and net operating margin are non-GAAP performance measures that are used by our management and others to compare our refining performance to that of other companies in our industry. We believe these margin measures are helpful to investors in evaluating our refining performance on a relative and absolute basis. We calculate refinery gross margin and net operating margin using net sales, cost of products and operating expenses, in each case averaged per produced barrel sold. These two margins do not include the effect of depreciation, depletion and amortization. Each of these component performance measures can be reconciled directly to our Consolidated Statements of Income.

Other companies in our industry may not calculate these performance measures in the same manner.

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Refinery Gross Margin

Refinery gross margin per barrel is the difference between average net sales price and average cost of products per barrel of produced refined products. Refinery gross margin for each of our refineries and for all of our refineries on a consolidated basis is calculated as shown below.

	Years Ended December 31,		
	2006	2005	2004
Average per produced barrel:			
Navajo Refinery			
Net sales	$ 79.62	$ 69.11	$ 51.42
Less cost of products	64.25	55.50	41.26
Refinery gross margin	$ 15.37	$ 13.61	$ 10.16
Woods Cross Refinery			
Net sales	$ 82.09	$ 69.13	$ 51.33
Less cost of products	64.99	59.51	45.33
Refinery gross margin	$ 17.10	$ 9.62	$ 6.00
Consolidated			
Net sales	$ 80.21	$ 69.12	$ 51.40
Less cost of products	64.43	56.50	42.20
Refinery gross margin	$ 15.78	$ 12.62	$ 9.20

Net Operating Margin

Net operating margin per barrel is the difference between refinery gross margin and refinery operating expenses per barrel of produced refined products. Net operating margin for each of our refineries and for all of our refineries on a consolidated basis is calculated as shown below.

	Years Ended December 31,		
	2006	2005	2004
Average per produced barrel:			
Navajo Refinery			
Refinery gross margin	$ 15.37	$ 13.61	$ 10.16
Less refinery operating expenses	4.74	3.94	3.20
Net operating margin	$ 10.63	$ 9.67	$ 6.96
Woods Cross Refinery			
Refinery gross margin	$ 17.10	$ 9.62	$ 6.00
Less refinery operating expenses	5.13	4.61	3.92

Net operating margin	$ 11.97	$ 5.01	$ 2.08
Consolidated			
Refinery gross margin	$ 15.78	$ 12.62	$ 9.20
Less refinery operating expenses	4.83	4.11	3.37
Net operating margin	$ 10.95	$ 8.51	$ 5.83

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Below are reconciliations to our Consolidated Statements of Income for (i) net sales, cost of products and operating expenses, in each case averaged per produced barrel sold, and (ii) net operating margin and refinery gross margin. Due to rounding of reported numbers, some amounts may not calculate exactly.

Reconciliations of refined product sales from produced products sold to total sales and other revenue

	Years Ended December 31, 2006	2005	2004
Navajo Refinery			
Average sales price per produced barrel sold	$ 79.62	$ 69.11	$ 51.42
Times sales of produced refined products sold (BPD)	79,940	80,110	78,880
Times number of days in period	365	365	366
Refined product sales from produced products sold	$ 2,323,160	$ 2,020,787	$ 1,484,500
Woods Cross Refinery			
Average sales price per produced barrel sold	$ 82.09	$ 69.13	$ 51.33
Times sales of produced refined products sold (BPD)	25,150	26,390	23,520
Times number of days in period	365	365	366
Refined product sales from produced products sold	$ 753,566	$ 665,884	$ 441,865
Sum of refined product sales from produced products sold from our two refineries (4)	$ 3,076,726	$ 2,686,671	$ 1,926,365
Add refined product sales from purchased products and rounding (1)	480,641	273,608	163,173
Total refined products sales	3,557,367	2,960,279	2,089,538
Add direct sales of excess crude oil(2)	323,002		
Add other refining segment revenue (3)	141,605	68,056	15,031
Total refining segment revenue	4,021,974	3,028,335	2,104,569
Add HEP sales and other revenue		36,034	28,182
Add corporate and other revenues	1,752	1,772	1,916
Subtract consolidations and eliminations	(509)	(19,828)	(18,422)
Sales and other revenues	$ 4,023,217	$ 3,046,313	$ 2,116,245

(1) We purchase finished products when opportunities arise that provide a profit on the sale of such products, or to meet

delivery commitments.

(2) *We purchase crude oil and enter into buy/sell exchanges in excess of the needs to supply our refineries. Certain direct sales of this excess crude oil are made to purchasers or users of crude oil. Under new accounting guidance, these sales and related purchases starting April 1, 2006 are being measured at fair value and accounted for as revenues with the related acquisition costs included as cost of products sold. Prior to April 1, 2006, sales and cost of sales attributable to such excess crude oil direct sales were netted and presented in cost of products sold.*

(3) *Other refining segment revenue includes the incremental revenues associated with*

NK Asphalt Partners subsequent to its consolidation in February 2005 and revenue derived from sulfur credit sales.

(4) The above calculations of refined product sales from produced products sold can also be computed on a consolidated basis. These amounts may not calculate exactly due to rounding of reported numbers.

	Years Ended December 31,		
	2006	**2005**	**2004**
Average sales prices per produced barrel sold	$ 80.21	$ 69.12	$ 51.40
Times sales of produced refined products sold (BPD)	105,090	106,500	102,400
Times number of days in period	365	365	366
Refined product sales from produced products sold	$ 3,076,726	$ 2,686,671	$ 1,926,365

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Reconciliation of average cost of products per produced barrel sold to total costs of products sold

	Years Ended December 31, 2006	2005	2004
Navajo Refinery			
Average cost of products per produced barrel sold	$ 64.25	$ 55.50	$ 41.26
Times sales of produced refined products sold (BPD)	79,940	80,110	78,880
Times number of days in period	365	365	366
Cost of products for produced products sold	$ 1,874,693	$ 1,622,828	$ 1,191,180
Woods Cross Refinery			
Average cost of products per produced barrel sold	$ 64.99	$ 59.51	$ 45.33
Times sales of produced refined products sold (BPD)	25,150	26,390	23,520
Times number of days in period	365	365	366
Cost of products for produced products sold	$ 596,592	$ 573,221	$ 390,215
Sum of cost of products for produced products sold from our two refineries (4)	$ 2,471,285	$ 2,196,049	$ 1,581,395
Add refined product costs from purchased products sold, certain hedging gains and rounding (1)	473,903	274,948	165,572
Total refined cost of products sold	2,945,188	2,470,997	1,746,967
Add crude oil cost of direct sales of excess crude oil(2)	323,337		
Add other refining segment costs of products sold (3)	81,388	47,641	
Total refining segment cost of products sold	3,349,913	2,518,638	1,746,967
Add corporate and other costs			
Subtract consolidations and eliminations	(509)	(19,828)	(18,422)
Costs of products sold (exclusive of depreciation, depletion and amortization)	$ 3,349,404	$ 2,498,810	$ 1,728,545

(1) We purchase finished products when opportunities arise that provide a profit on the sale of such products, or to meet delivery commitments. Additionally

during 2005, we entered into petroleum futures transactions hedging forecasted diesel fuel sales. The positions were fully liquidated during August to November 2005 resulting in gains of $3.2 million for the year ending December 31, 2005, which are recorded as a reduction in cost of products sold.

(2) We purchase crude oil and enter into buy/sell exchanges in excess of the needs to supply our refineries. Certain direct sales of this excess crude oil are made to purchasers or users of crude oil. Under new accounting guidance, these sales and related purchases starting April 1, 2006 are being measured at fair value and accounted for as revenues with

the related acquisition costs included as cost of products sold. Prior to April 1, 2006, sales and cost of sales attributable to such excess crude oil direct sales were netted and presented in cost of products sold.

(3) *Other refining segment costs of products sold includes the incremental costs of products for NK Asphalt Partners subsequent to its consolidation in February 2005 and costs attributable to sulfur credit sales.*

(4) *The above calculations of costs of products from produced products sold can also be computed on a consolidated basis. These amounts may not calculate exactly due to rounding of reported numbers.*

Years Ended December 31,

	2006	2005	2004
Average cost of products per produced barrel sold	$ 64.43	$ 56.50	$ 42.20
Times sales of produced refined products sold (BPD)	105,090	106,500	102,400
Times number of days in period	365	365	366
Cost of products for produced products sold	$ 2,471,285	$ 2,196,049	$ 1,581,395

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Reconciliation of average refinery operating expenses per produced barrel sold to total operating expenses

	Years Ended December 31, 2006	2005	2004
Navajo Refinery			
Average refinery operating expenses per produced barrel sold	$ 4.74	$ 3.94	$ 3.20
Times sales of produced refined products sold (BPD)	79,940	80,110	78,880
Times number of days in period	365	365	366
Refinery operating expenses for produced products sold	$ 138,304	$ 115,206	$ 92,384
Woods Cross Refinery			
Average refinery operating expenses per produced barrel sold	$ 5.13	$ 4.61	$ 3.92
Times sales of produced refined products sold (BPD)	25,150	26,390	23,520
Times number of days in period	365	365	366
Refinery operating expenses for produced products sold	$ 47,092	$ 44,405	$ 33,745
Sum of refinery operating expenses per produced products sold from our two refineries (2)	$ 185,396	$ 159,611	$ 126,129
Add other refining segment operating expenses and rounding (1)	23,015	20,545	18,486
Total refining segment operating expenses	208,411	180,156	144,615
Add HEP operating expenses		11,836	10,103
Add corporate and other costs	49	59	166
Operating expenses (exclusive of depreciation, depletion and amortization)	$ 208,460	$ 192,051	$ 154,884

(1) Other refining segment operating expenses include the marketing costs associated with our refining segment and the incremental operating expenses of NK Asphalt Partners

subsequent to its consolidation in February 2005 and the operating expenses during 2004 of terminal and pipeline assets now owned by HEP.

(2) *The above calculations of refinery operating expenses from produced products sold can also be computed on a consolidated basis. These amounts may not calculate exactly due to rounding of reported numbers.*

	Years Ended December 31,		
	2006	**2005**	**2004**
Average refinery operating expenses per produced barrel sold	$ 4.83	$ 4.11	$ 3.37
Times sales of produced refined products sold (BPD)	105,090	106,500	102,400
Times number of days in period	365	365	366
Refinery operating expenses for produced products sold	$ 185,396	$ 159,611	$ 126,129

<u>Reconciliation of net operating margin per barrel to refinery gross margin per barrel to total sales and other revenues</u>

	Years Ended December 31,		
	2006	**2005**	**2004**
Navajo Refinery			
Net operating margin per barrel	$ 10.63	$ 9.67	$ 6.96
Add average refinery operating expenses per produced barrel	4.74	3.94	3.20
Refinery gross margin per barrel	15.37	13.61	10.16
Add average cost of products per produced barrel sold	64.25	55.50	41.26
Average sales price per produced barrel sold	$ 79.62	$ 69.11	$ 51.42

Times sales of produced refined products sold (BPD)	79,940	80,110	78,880
Times number of days in period	365	365	366
Refined product sales from produced products sold	$ 2,323,160	$ 2,020,787	$ 1,484,500

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	Years Ended December 31,		
	2006	2005	2004
Woods Cross Refinery			
Net operating margin per barrel	$ 11.97	$ 5.01	$ 2.08
Add average refinery operating expenses per produced barrel	5.13	4.61	3.92
Refinery gross margin per barrel	17.10	9.62	6.00
Add average cost of products per produced barrel sold	64.99	59.51	45.33
Average sales price per produced barrel sold	$ 82.09	$ 69.13	$ 51.33
Times sales of produced refined products sold (BPD)	25,150	26,390	23,520
Times number of days in period	365	365	366
Refined product sales from produced products sold	$ 753,566	$ 665,884	$ 441,865
Sum of refined product sales from produced products sold from our two refineries (4)	$ 3,076,726	$ 2,686,671	$ 1,926,365
Add refined product sales from purchased products and rounding (1)	480,641	273,608	163,173
Total refined product sales	3,557,367	2,960,279	2,089,538
Add direct sales of excess crude oil(2)	323,002		
Add other refining segment revenue (3)	141,605	68,056	15,031
Total refining segment revenue	4,021,974	3,028,335	2,104,569
Add HEP sales and other revenues		36,034	28,182
Add corporate and other revenues	1,752	1,772	1,916
Subtract consolidations and eliminations	(509)	(19,828)	(18,422)
Sales and other revenues	$ 4,023,217	$ 3,046,313	$ 2,116,245

(1) We purchase finished products when opportunities arise that provide a profit on the sale of such products or to meet delivery commitments.

(2) We purchase crude oil and

enter into buy/sell exchanges in excess of the needs to supply our refineries. Certain direct sales of this excess crude oil are made to purchasers or users of crude oil. Under new accounting guidance, these sales and related purchases starting April 1, 2006 are being measured at fair value and accounted for as revenues with the related acquisition costs included as cost of products sold. Prior to April 1, 2006, sales and cost of sales attributable to such excess crude oil direct sales were netted and presented in cost of products sold.

(3) Other refining segment revenue includes the revenues associated with NK Asphalt Partners subsequent to its consolidation in February 2005, revenue derived

from sulfur credit sales and revenues during 2004 from terminal and pipeline assets that are now owned by HEP.

(4) *The above calculations of refined product sales from produced products sold can also be computed on a consolidated basis. These amounts may not calculate exactly due to rounding of reported numbers.*

	Years Ended December 31,		
	2006	**2005**	**2004**
Net operating margin per barrel	$ 10.95	$ 8.51	$ 5.83
Add average refinery operating expenses per produced barrel	4.83	4.11	3.37
Refinery gross margin per barrel	15.78	12.62	9.20
Add average cost of products per produced barrel sold	64.43	56.50	42.20
Average sales price per produced barrel sold	$ 80.21	$ 69.12	$ 51.40
Times sales of produced refined products sold (BPD)	105,090	106,500	102,400
Times number of days in period	365	365	366
Refined product sales from produced products sold	$ 3,076,726	$ 2,686,671	$ 1,926,365

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Item 8. Financial Statements and Supplementary Data

MANAGEMENT S REPORT ON ITS ASSESSMENT OF THE COMPANY S INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Holly Corporation (the Company) is responsible for establishing and maintaining adequate internal control over financial reporting.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the Company s internal control over financial reporting as of December 31, 2006 using the criteria for effective control over financial reporting established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that, as of December 31, 2006, the Company maintained effective internal control over financial reporting.

The Company s independent registered public accounting firm has issued an attestation report on management s assessment of the Company s internal control over financial reporting. That report appears on page 57.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have audited management s assessment, included in the accompanying Management s Report on Its Assessment of the Company s Internal Control Over Financial Reporting , that Holly Corporation maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Holly Corporation s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management s assessment that Holly Corporation maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on criteria established in Internal Control Integrated Framework issued by the COSO. Also, in our opinion, Holly Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control Integrated Framework issued by the COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Holly Corporation as of December 31, 2006 and 2005, and the related consolidated statements of income, cash flows, stockholders equity and comprehensive income for each of the three years in the period ended December 31, 2006 of Holly Corporation and our report dated February 28, 2007 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
Dallas, Texas
February 28, 2007

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
and Stockholders of Holly Corporation

We have audited the accompanying consolidated balance sheets of Holly Corporation as of December 31, 2006 and 2005, and the related consolidated statements of income, cash flows, stockholders equity and comprehensive income for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 1 and Note 5 to the consolidated financial statements, in 2006 and 2005, respectively, the Company adopted Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans and No. 123(r), Share-Based Payments.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Holly Corporation at December 31, 2006 and 2005, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Holly Corporation s internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 28, 2007 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
Dallas, Texas
February 28, 2007

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HOLLY CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December 31, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 154,117	$ 49,064
Marketable securities	96,168	189,978
Accounts receivable: Product and transportation	199,083	145,736
Crude oil resales	196,842	254,734
Related party receivable	2,198	1,434
	398,123	401,904
Inventories: Crude oil and refined products	115,100	91,257
Materials and supplies	14,575	12,082
	129,675	103,339
Income taxes receivable	9,055	
Prepayments and other	19,359	14,639
Assets of discontinued operations	355	30,612
Total current assets	806,852	789,536
Properties, plants and equipment, at cost	642,740	532,641
Less accumulated depreciation, depletion and amortization	(237,270)	(216,502)
	405,470	316,139
Marketable securities (long-term)	5,668	15,800
Other assets: Turnaround costs (long-term)	4,783	7,321
Intangibles and other	15,096	14,104
	19,879	21,425
Total assets	$ 1,237,869	$ 1,142,900
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 507,566	$ 518,584
Accrued liabilities	51,173	41,235

Income taxes payable		5,538
Liabilities of discontinued operations	654	14,076
Total current liabilities	559,393	579,433
Deferred income taxes	20,776	9,989
Other long-term liabilities	27,201	19,101
Commitments and contingencies		
Distributions in excess of investment in Holly Energy Partners	164,405	157,026
Stockholders equity:		
Preferred stock, $1.00 par value 1,000,000 shares authorized; none issued		
Common stock $.01 par value 100,000,000 and 50,000,000 shares authorized; 71,825,960 and 35,378,646 shares issued as of December 31, 2006 and 2005, respectively	718	354
Additional capital	66,500	43,344
Retained earnings	745,994	495,819
Accumulated other comprehensive loss	(11,358)	(4,802)
Common stock held in treasury, at cost 16,509,345 and 6,002,175 shares as of December 31, 2006 and 2005, respectively	(335,760)	(157,364)
Total stockholders equity	466,094	377,351
Total liabilities and stockholders equity	$ 1,237,869	$ 1,142,900

See accompanying notes.

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HOLLY CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per share data)

	Years Ended December 31,		
	2006	**2005**	**2004**
Sales and other revenues	$ 4,023,217	$ 3,046,313	$ 2,116,245
Operating costs and expenses:			
Cost of products sold (exclusive of depreciation, depletion and amortization)	3,349,404	2,498,810	1,728,545
Operating expenses (exclusive of depreciation, depletion and amortization)	208,460	192,051	154,884
General and administrative expenses (exclusive of depreciation, depletion and amortization)	63,255	51,683	50,693
Depreciation, depletion and amortization	39,721	40,547	37,457
Exploration expenses, including dry holes	486	481	689
Total operating costs and expenses	3,661,326	2,783,572	1,972,268
Income from operations	361,891	262,741	143,977
Other income (expense):			
Equity in loss of joint ventures		(685)	(318)
Equity in earnings of Holly Energy Partners	12,929	6,517	
Minority interests in income of partnerships		(6,721)	(7,575)
Interest income	9,757	6,901	4,369
Interest expense	(1,076)	(5,101)	(3,524)
	21,610	911	(7,048)
Income from continuing operations before income taxes	383,501	263,652	136,929
Income tax provision:			
Current	126,181	105,333	79,065
Deferred	10,422	(5,707)	(25,080)
	136,603	99,626	53,985
Income from continuing operations	246,898	164,026	82,944
Discontinued operations			
Income from discontinued operations	5,660	2,963	935
Gain on sale of discontinued operations	14,008		
Income from discontinued operations, net of taxes	19,668	2,963	935

Net income before cumulative effect of change in accounting principle		266,566		166,989		83,879
Cumulative effect of accounting change (net of income tax expense of $426)				669		
Net income	$	266,566	$	167,658	$	83,879
Basic earnings per share:						
Continuing operations	$	4.33	$	2.66	$	1.32
Discontinued operations		0.35		0.05		0.02
Cumulative effect of accounting change				0.01		
Net income	$	4.68	$	2.72	$	1.34
Diluted earnings per share:						
Continuing operations	$	4.24	$	2.59	$	1.29
Discontinued operations		0.34		0.05		0.01
Cumulative effect of accounting change				0.01		
Net income	$	4.58	$	2.65	$	1.30
Cash dividends declared per common share	$	0.29	$	0.19	$	0.145
Average number of common shares outstanding:						
Basic		56,976		61,728		62,780
Diluted		58,210		63,244		64,340

See accompanying notes.

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HOLLY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31,		
	2006	**2005**	**2004**
Cash flows from operating activities:			
Net income	$ 266,566	$ 167,658	$ 83,879
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization (includes discontinued operations)	40,270	43,817	40,481
Deferred income taxes (includes discontinued operations)	7,980	(5,822)	(25,384)
Minority interests in income of partnerships		6,721	7,575
Distributions in excess of equity in earnings of Holly Energy Partners and joint ventures	7,379	3,050	4,728
Equity based compensation expense	5,507	2,163	3,419
Gain on sale of assets, before income taxes	(22,328)		
(Increase) decrease in current assets:			
Accounts receivable	12,059	(128,301)	(97,397)
Inventories	(33,792)	1,797	7,379
Income taxes receivable	(9,055)	10,735	1,411
Prepayments and other	(1,388)	795	(3,908)
Increase (decrease) in current liabilities:			
Accounts payable	(26,370)	143,289	99,029
Accrued liabilities	15,665	6,155	18,024
Income taxes payable	(5,323)	1,388	
Turnaround expenditures	(7,672)	(1,077)	(7,450)
Prepaid transportation			25,000
Other, net	(4,315)	(1,134)	7,818
Net cash provided by operating activities	245,183	251,234	164,604
Cash flows from investing activities:			
Additions to properties, plants and equipment	(120,429)	(106,262)	(37,780)
Net cash proceeds from sale of Montana Refinery	48,872		
Acquisition by Holly Energy Partners of pipeline and terminal assets		(121,853)	
Decrease in cash due to deconsolidation of Holly Energy Partners		(20,447)	
Purchase Holly Energy Partners restricted units			(223)
Investments and advances to joint ventures			(3,314)
Purchase of additional interests in joint venture, net of cash		(18,360)	
Purchases of marketable securities	(211,972)	(322,046)	(271,720)
Sales and maturities of marketable securities	319,334	268,001	119,034
Proceeds from the sale of partial interest in joint venture		832	
Net cash provided by (used for) investing activities	35,805	(320,135)	(194,003)

Cash flows from financing activities:			
Proceeds from issuance of Holly Energy Partners :			
Senior notes, net of underwriter discount		181,955	
Common units, net of offering costs		43,788	141,974
Payment of long-term debt		(8,572)	(8,570)
Net decrease in borrowings under revolving credit agreements		(25,000)	(25,000)
Debt issuance costs		(948)	(3,603)
Issuance of common stock upon exercise of options	2,645	2,782	4,655
Purchase of treasury stock	(175,394)	(130,763)	(15,293)
Sale of treasury stock		1,957	
Cash dividends	(15,002)	(11,243)	(8,281)
Cash distributions to minority interests		(9,486)	(6,282)
Excess tax benefit from equity based compensation	11,816	6,035	5,569
Net cash provided by (used for) financing activities	(175,935)	50,505	85,169
Cash and cash equivalents:			
Increase (decrease) for the period	105,053	(18,396)	55,770
Beginning of period	49,064	67,460	11,690
End of period	$ 154,117	$ 49,064	$ 67,460

See accompanying notes.

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HOLLY CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
(In thousands)

	Common Stock	Additional Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total Stockholders Equity
Balance at December 31, 2003	$ 169	$ 15,818	$ 264,991	$ 130	$ (12,499)	$ 268,609
Net income			83,879			83,879
Dividends			(9,072)			(9,072)
Other comprehensive loss				(1,849)		(1,849)
Issuance of common stock upon exercise of stock options	6	4,649				4,655
Tax benefit from stock options		5,568				5,568
Issuance of restricted stock, net of forfeitures		3,419				3,419
Purchase of treasury stock					(15,293)	(15,293)
Two-for-one stock split	173	(173)				
Balance at December 31, 2004	$ 348	$ 29,281	$ 339,798	$ (1,719)	$ (27,792)	$ 339,916
Net income			167,658			167,658
Dividends			(11,637)			(11,637)
Other comprehensive loss				(3,083)		(3,083)
Issuance of common stock upon exercise of stock options	6	2,776				2,782
Tax benefit from stock options		5,815				5,815
Amortization of stock options		468				468
Issuance of restricted stock, net of forfeitures		2,503				2,503
Tax benefit from restricted stock		411				411
Purchase of treasury stock					(130,763)	(130,763)
Sale of treasury stock		2,090			1,191	3,281

Balance at December 31, 2005	$ 354	$ 43,344	$ 495,819	$ (4,802)	$ (157,364)	$ 377,351
Net income			266,566			266,566
Dividends			(16,391)			(16,391)
Other comprehensive income				2,831		2,831
Issuance of common stock upon exercise of stock options	6	2,638				2,644
Tax benefit from stock options		12,031				12,031
Amortization of stock options		139				139
Issuance of restricted stock, net of forfeitures		5,369				5,369
Other equity based compensation		3,337				3,337
Purchase of treasury stock					(178,396)	(178,396)
Two-for-one stock split	358	(358)				
Adjustment to initially apply SFAS No. 158, net of tax				(9,387)		(9,387)
Balance at December 31, 2006	$ 718	$ 66,500	$ 745,994	$ (11,358)	$ (335,760)	$ 466,094

See accompanying notes.

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HOLLY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In thousands)

	Years Ended December 31,		
	2006	**2005**	**2004**
Net income	$ 266,566	$ 167,658	$ 83,879
Other comprehensive income (loss):			
Securities available-for-sale:			
Unrealized gain (loss) on available-for-sale securities	(777)	183	(435)
Reclassification adjustment to net income on sale of securities	(131)	(255)	16
Total unrealized loss on available-for-sale securities	(908)	(72)	(419)
Minimum pension liability adjustment	5,542	(4,973)	(2,006)
Derivative instruments qualifying as cash flow hedging instruments:			
Change in fair value of derivative instruments			(329)
Reclassification adjustment to net income			(270)
Total loss on cash flow hedges			(599)
Other comprehensive loss before income taxes	4,634	(5,045)	(3,024)
Income tax benefit	(1,803)	(1,962)	(1,175)
Other comprehensive income (loss)	2,831	(3,083)	(1,849)
Total comprehensive income	$ 269,397	$ 164,575	$ 82,030

See accompanying notes.

NOTE 1: Description of Business and Summary of Significant Accounting Policies

Description of Business: References herein to Holly Corporation include Holly Corporation and its consolidated subsidiaries. In accordance with the Securities and Exchange Commission s (SEC) Plain English guidelines, this Annual Report on Form 10-K has been written in the first person. In this document, the words we , our , ours and us refer only to Holly Corporation and its consolidated subsidiaries or to Holly Corporation or an individual subsidiary and not to any other person.

We are principally an independent petroleum refiner, who produces high value light products such as gasoline, diesel fuel and jet fuel. Navajo Refining Company, L.P., one of our wholly-owned subsidiaries, owns a petroleum refinery in Artesia, New Mexico, which operates in conjunction with crude, vacuum distillation and other facilities situated 65 miles away in Lovington, New Mexico (collectively, the Navajo Refinery). The Navajo Refinery can process sour (high sulfur) crude oils and serves markets in the southwestern United States and northern Mexico. In June 2003, we completed the acquisition of the Woods Cross refining facility from ConocoPhillips. The Woods Cross refinery (Woods Cross Refinery), located just north of Salt Lake City, Utah, is operated by Holly Refining & Marketing Company Woods Cross, one of our wholly-owned subsidiaries. This facility is a high conversion refinery that primarily processes regional sweet (lower sulfur) and sour Canadian crude oils. In conjunction with the refining and pipeline operations, we own a system of crude oil gathering pipelines.

In July 2004, we completed an initial public offering of limited partnership interests in Holly Energy Partners, L.P. (HEP), a Delaware limited partnership which following its formation was owned 51% by us and 49% by other investors in HEP. On February 28, 2005, HEP closed on the acquisition of assets from Alon USA, Inc. and certain of its affiliates (collectively, Alon). This purchase reduced our ownership in HEP to 47.9%. On July 8, 2005, we closed on a transaction for HEP to acquire our two parallel intermediate feedstock pipelines which connect our Lovington and Artesia, New Mexico facilities, which reduced our ownership in HEP to 45%.

At December 31, 2006, HEP had logistics assets including petroleum product pipelines located in Texas, New Mexico and Oklahoma; eleven refined product terminals; two refinery truck rack facilities, a refined products tank farm facility and a 70% interest in Rio Grande Pipeline Company (Rio Grande), which owns a pipeline that transports liquid petroleum gases, or LPG s, from west Texas to the Texas/Mexico border near El Paso for further transport into northern Mexico.

On March 31, 2006 we sold our petroleum refinery in Great Falls, Montana (the Montana Refinery) to a subsidiary of Connacher Oil and Gas Limited (Connacher). Accordingly, the results of operations of the Montana Refinery and a net gain of $14.0 million on the sale are shown in discontinued operations (see Note 2).

In February 2005, we purchased the 51% interest in NK Asphalt Partners owned by a subsidiary of Koch Materials Company (Koch) increasing our ownership in NK Asphalt Partners from 49% to 100%. The partnership which manufactures and markets asphalt and asphalt products in Arizona and New Mexico now does business under the name of Holly Asphalt Company. See Note 9 for additional information regarding the purchase made in February 2005.

We also conduct a small-scale oil and gas exploration and production program and had a small investment in a joint venture, MRC Hi-Noon LLC, that operated retail gasoline stations and convenience stores in Montana. See Note 9 for information regarding the sale of our 49% interest in MRC Hi-Noon LLC to our joint venture partner on February 28, 2005.

Principles of Consolidation: Our consolidated financial statements include our accounts and the accounts of partnerships and joint ventures that we control through 50% or more ownership or through 50% or more variable interest in entities that are considered variable interest entities. All significant intercompany transactions and balances have been eliminated.

Use of Estimates: The preparation of financial statements in accordance with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Reclassifications: Certain reclassifications, which we determined to be immaterial, have been made to prior balances to conform to the classifications used for 2006.
Cash Equivalents: We consider all highly liquid instruments with a maturity of three months or less at the date of purchase to be cash equivalents. Cash equivalents are stated at cost, which approximates market value and are primarily invested in conservative, highly-rated instruments issued by financial institutions or government entities with strong credit standings.
Marketable Securities: We consider all marketable debt securities with maturities greater than three months at the date of purchase to be marketable securities. Our marketable securities are primarily issued by government entities with the maximum maturity of any individual issue not more than two years, while the maximum duration of the portfolio of investments is not greater than one year. These instruments are classified as available-for-sale, and as a result, are reported at fair value. Unrealized gains and losses, net of related income taxes, are reported as a component of accumulated other comprehensive income.
Accounts Receivable: The majority of the accounts receivable are due from companies in the petroleum industry. Credit is extended based on evaluation of the customer s financial condition and in certain circumstances, collateral, such as letters of credit or guarantees, is required. Credit losses are charged to income when accounts are deemed uncollectible and historically have been minimal. Accounts receivable attributable to crude oil resales generally represent the sell side of reciprocal crude oil buy/sell exchange arrangements involved in supplying crude oil to the refineries and resales to other purchasers or users of crude oil with an approximate like amount reflected in accounts payable. In many cases, we enter into net settlement agreements relating to the buy/sell arrangements, which may mitigate credit risk.
Inventories: Inventories are stated at the lower of cost, using the last-in, first-out (LIFO) method for crude oil and refined products and the average cost method for materials and supplies, or market. Cost is determined using the LIFO inventory valuation methodology and market is determined using current estimated selling prices. Under the LIFO method, the most recently incurred costs are charged to cost of sales and inventories are valued at the earliest acquisition costs. In periods of rapidly declining prices, LIFO inventories may have to be written down to market due to the higher costs assigned to LIFO layers in prior periods. In addition, the use of the LIFO inventory method may result in increases or decreases to cost of sales in years that inventory volumes decline as the result of charging cost of sales with LIFO inventory costs generated in prior periods. An actual valuation of inventory under the LIFO method can be made only at the end of each year based on the inventory levels and costs at that time. Accordingly, interim LIFO calculations are based on management s estimates of expected year-end inventory levels and costs and are subject to the final year-end LIFO inventory valuation.
Long-lived assets: We calculate depreciation and amortization based on estimated useful lives and salvage values of our assets. We evaluate long-lived assets for potential impairment by identifying whether indicators of impairment exist and, if so, assessing whether the long-lived assets are recoverable from estimated future undiscounted cash flows. The actual amount of impairment loss, if any, to be recorded is equal to the amount by which a long-lived asset s carrying value exceeds its fair value. No impairments of long-lived assets were recorded during the years ended December 31, 2006, 2005 and 2004.
Asset Retirement Obligations: We record legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of long-lived assets. The fair value of the estimated cost to retire a tangible long-lived asset is recorded in the period in which the liability is incurred and when a reasonable estimate of the fair value of the liability can be made. If a reasonable estimate cannot be made at the time the liability is incurred, we record the liability when sufficient information is available to estimate the liability s fair value.
We have asset retirement obligations with respect to certain assets due to legal obligations to clean and/or dispose of various component parts at the time they were retired. At December 31, 2006, we have an asset retirement obligation of $0.8 million, which is included in Other long-term liabilities in our consolidated balance sheets.
Intangibles and Goodwill: Intangible assets are assets (other than financial assets) that lack physical substance. Goodwill represents the excess of the cost of an acquired entity over the fair value of the assets acquired less

liabilities assumed. Goodwill acquired in a business combination and intangible assets with indefinite useful lives are not amortized and intangible assets with finite useful lives are amortized. Goodwill and intangible assets not subject to amortization are tested for impairment annually or more frequently if events or changes in circumstances indicate the asset might be impaired. No impairments of intangibles or goodwill were recorded during the years ended December 31, 2006, 2005 and 2004.

Investment in HEP: Through June 30, 2005, our financial statements included the consolidated results of HEP, with the interest we did not own reported as a minority interest in the ownership and earnings. Under the provisions of FASB Interpretation No. 46 (revised) (FIN 46), Consolidation of Variable Interest Entities, we have deconsolidated HEP effective July 1, 2005. From July 1, 2005 forward our share of the earnings of HEP is reported using the equity method of accounting (see Note 3).

Investments in Joint Ventures: We have accounted for investments in and earnings from joint ventures where we have ownership of 50% or less using the equity method.

Revenue Recognition: Refined product sales and related cost of sales are recognized when products are shipped and title has passed to customers. Pipeline transportation revenues are recognized as products are shipped on our pipelines. Additional pipeline transportation revenues result from the lease of an interest in the capacity of an HEP pipeline. All revenues are reported inclusive of shipping and handling costs billed and exclusive of any taxes billed to customers. Shipping and handling costs incurred are reported in cost of products sold.

Depreciation: Depreciation is provided by the straight-line method over the estimated useful lives of the assets, primarily 10 to 12 years for refining facilities, 10 to 30 years for pipeline and terminal facilities, 3 to 5 years for transportation vehicles, 10 to 40 years for buildings and improvements and 7 to 30 years for other fixed assets.

Cost Classifications: Costs of products sold include the cost of crude oil, other feedstocks, blendstocks and purchased finished products, inclusive of transportation costs. To provide the desired crude oil to our refineries, we utilize a combination of crude oil purchases from producers and other petroleum companies and enter into crude oil buy/sell exchanges. When crude oil is purchased in excess of the needs of our refineries, we may resell to other purchasers or users of crude oil. The acquisition costs related to these buy/sell crude oil transactions is recorded in cost of products sold. Operating expenses include direct costs of labor, maintenance materials and services, utilities, marketing expense and other direct operating costs. General and administrative expenses include compensation, professional services and other support costs.

Deferred Maintenance Costs: Our refinery units require regular major maintenance and repairs which are commonly referred to as turnarounds . Catalysts used in certain refinery processes also require regular change-outs . The required frequency of the maintenance varies by unit and by catalyst, but generally is every two to five years. Turnaround costs are deferred and amortized over the period until the next scheduled turnaround. Other repairs and maintenance costs are expensed when incurred.

Environmental Costs: Environmental costs are expensed if they relate to an existing condition caused by past operations and do not contribute to current or future revenue generation. Liabilities are recorded when site restoration and environmental remediation, cleanup and other obligations are either known or considered probable and can be reasonably estimated. Recoveries of environmental costs through insurance, indemnification arrangements or other sources are included in other assets to the extent such recoveries are considered probable.

Contingencies: We are subject to proceedings, lawsuits and other claims related to environmental, labor, product and other matters. We are required to assess the likelihood of any adverse judgments or outcomes to these matters as well as potential ranges of probable losses. A determination of the amount of reserves required, if any, for these contingencies is made after careful analysis of each individual issue. The required reserves may change in the future due to new developments in each matter or changes in approach such as a change in settlement strategy in dealing with these matters.

Stock-Based Compensation: In December 2004, the FASB issued SFAS No. 123 (revised), Share-Based Payment. This revision prescribes the accounting for a wide-range of share-based compensation arrangements, including share options, restricted share plans, performance-based awards, share appreciation rights and employee share purchase plans, and generally requires the fair value of share-based awards to be expensed on the income statement. We elected early adoption of this standard effective July 1, 2005 based on modified retrospective application with early application under SFAS No. 123 (revised) to prior quarters of 2005. Also as part of this adoption, we recorded a cumulative effect of a change in accounting principle relating to our performance units due to the initial effect of measuring these awards at fair value where they were previously measured at intrinsic value. See Note 5 for additional information regarding our adoption of SFAS No. 123 (revised).

Income Taxes: Provisions for income taxes include deferred taxes resulting from temporary differences in income for financial and tax purposes, using the liability method of accounting for income taxes. The liability method requires the effect of tax rate changes on current and accumulated deferred income taxes to be reflected in the period in which the rate change was enacted. The liability method also requires that deferred tax assets be reduced by a valuation allowance unless it is more likely than not that the assets will be realized.

Derivative Instruments: All derivative instruments are recognized as either assets or liabilities in the balance sheet and measured at their fair value. Changes in the derivative instrument s fair value are recognized currently in earnings unless specific hedge accounting criteria are met. See Note 16 for additional information on derivative instruments and hedging activities.

New Accounting Pronouncements:

EITF No. 04-13 Accounting for Purchases and Sales of Inventory with the Same Counterparty

The Emerging Issues Task Force reached a consensus on Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty, and the FASB ratified it in September 2005. This standard addresses accounting matters that arise when one company both sells inventory to and buys inventory from another company in the same line of business, specifically, when it is appropriate to measure purchases and sales of inventory at fair value and record them in cost of sales and revenues and when purchases and sales should be recorded as an exchange measured at the book value of the item sold. The consensus in this standard is to be applied to new arrangements entered into in reporting periods beginning after March 15, 2006. We adopted this standard effective April 1, 2006 and no longer account for certain crude oil transactions on a net basis.

In contemplation of the adoption of EITF 04-13, we modified our accounting procedures to identify the sale of crude oil determined to be in excess of our refinery requirements. These sales and related purchases are accounted for prospectively from April 1, 2006, as revenues with the related acquisition costs included in cost of products sold. Prior to the adoption of EITF 04-13, sales and cost of sales attributable to such excess crude oil sales were netted and presented in cost of products sold as amounts were not directly identified in our accounting systems and we believe they are immaterial to the presentation of our consolidated statements of income. For the year ended December 31, 2006, these crude oil sales amounted to $323.0 million with corresponding costs of $323.3 million.

Interpretation No. 48 Accounting for Uncertainty in Income Taxes

In June 2006, the FASB issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes. This interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements by prescribing a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. This interpretation is effective for fiscal years beginning after December 15, 2006. We will adopt this interpretation effective for our 2007 fiscal year. We do not anticipate that the adoption of this standard will have a material effect on our financial condition, results of operations and cash flows.

SFAS No. 157 Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This standard simplifies and codifies guidance on fair value measurements under generally accepted accounting principles. This standard defines fair value, establishes a framework for measuring fair value and prescribes expanded disclosures about fair value measurements. This standard is effective for fiscal years beginning after November 15, 2007. We do not anticipate that the adoption of this interpretation will have a material effect on our financial condition, results of operations and cash flows.

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SFAS No. 158 Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an Amendment of FASB Statements No. 87, 88, 106, and 132(R)

In September 2006, the FASB issued SFAS No. 158, Employer s Accounting for Defined Benefit Pension and Other Postretirement Plans, an Amendment of FASB Statements no. 87, 88, 106 and 132(R). This amendment requires an employer to recognize the funded status of a defined benefit postretirement plan as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. This standard also requires an employer to measure the funded status of a plan as of the date of its year-end financial statements. This standard is effective for fiscal years ending after December 15, 2006. We adopted this standard effective December 31, 2006 which resulted in the recognition of a net unrealized actuarial loss and prior service costs totaling $15.4 million as a component of accumulated other comprehensive loss. See Note 15 for additional information regarding the adoption of SFAS No. 158.

NOTE 2: Discontinued Operations

On March 31, 2006 we sold the Montana Refinery to Connacher. The net cash proceeds we received on the sale of the Montana Refinery amounted to $48.9 million, net of transaction fees and expenses. Additionally we received 1,000,000 shares of Connacher common stock valued at $4.3 million at March 31, 2006. In accounting for the sale, we recorded a pre-tax gain of $22.3 million. The Montana Refinery assets disposed of had a net book value at March 31, 2006 of $13.7 million for property, plant and equipment, $15.4 million for inventories and $2.1 million for other assets, with current liabilities assumed amounting to $0.3 million.

We retained certain quantities of finished product inventories that were not included in the sale to Connacher. These inventories were liquidated during the second quarter of 2006.

The following tables provide summarized income statement information related to discontinued operations:

	Years Ended December 31, 2006	2005	2004
		(In thousands)	
Sales and other revenues from discontinued operations	$ 53,913	$ 166,432	$ 130,128
Income from discontinued operations before income taxes	$ 9,021	$ 4,761	$ 1,540
Income tax expense	(3,361)	(1,798)	(605)
Income from discontinued operations, net	5,660	2,963	935
Gain on sale of discontinued operations before income taxes	22,328		
Income tax expense	(8,320)		
Gain on sale of discontinued operations, net	14,008		
Income from discontinued operations, net	$ 19,668	$ 2,963	$ 935

In accordance with the Montana Refinery sale agreement, we retained certain financial liabilities, including certain environmental liabilities related to required remediation and corrective action for environmental conditions that existed at the time of sale and for financial penalties for infractions that occurred prior to the sale. Based on our estimates, we have accrued $1.3 million as of December 31, 2006 related to such environmental liabilities which is included in our environmental liability accrual as discussed in Note 10.

NOTE 3: Investment in Holly Energy Partners

HEP is a publicly held master limited partnership that commenced operations July 13, 2004 upon the completion of its initial public offering. We currently have a 45% ownership interest in HEP, including our 2% general partner interest.

HEP serves our refineries in New Mexico and Utah under a 15-year pipelines and terminals agreement (HEP PTA) expiring in 2019 and a 15-year intermediate pipeline agreement expiring in 2020 (HEP IPA). Under the HEP PTA, we pay HEP fees to transport on their refined product pipelines or throughput in their terminals volumes of refined products that will result in minimum annual payments to HEP, currently $38.5 million. Under the HEP IPA, we agreed to transport minimum volumes of intermediate products on the intermediate pipelines that will result in minimum annual payments to HEP, currently $12.4 million. Minimum payments for both agreements will adjust upward based on increases in the producer price index over the term of the agreements. Additionally, we agreed to indemnify HEP up to an aggregate amount of $17.5 million for any environmental noncompliance and remediation liabilities associated with the assets transferred to HEP and occurring or existing prior to the date of the transfers of ownership to HEP. Of this total, indemnification in excess of $15.0 million relates solely to the intermediate pipelines.

On February 28, 2005, HEP closed its acquisition from Alon of four refined products pipelines, an associated tank farm and two refined products terminals. These pipelines and terminals are located primarily in Texas and transport approximately 70% of the light refined products for Alon s refinery in Big Spring, Texas. The total consideration paid by HEP for these pipeline and terminal assets was $120.0 million in cash and 937,500 Class B subordinated units which, subject to certain conditions, will convert into an equal number of HEP common units five years after the acquisition date. Following the closing of this transaction, we owned 47.9% of HEP including the 2% general partner interest. HEP financed the Alon transaction through a private offering of $150.0 million principal amount of 6.25% senior notes due 2015 (HEP Senior Notes). HEP used the proceeds of the offering to fund the $120.0 million cash portion of the consideration for the Alon transaction, and used the balance to repay $30.0 million of outstanding indebtedness under HEP s credit agreement, including $5.0 million drawn shortly before the closing of the Alon transaction. The consideration paid for the Alon pipeline and terminal assets was allocated to the individual assets acquired based on their estimated fair values. The aggregate consideration amounted to $146.6 million, which consisted of $24.7 million fair value of HEP s Class B subordinated units, $120.0 million in cash and $1.9 million of transaction costs. In accounting for this acquisition, HEP recorded pipeline and terminal assets of $86.9 million and an intangible asset of $59.7 million, representing the value of the 15-year pipelines and terminals agreement.

On July 8, 2005, we closed on the transaction in which HEP acquired our two parallel intermediate feedstock pipelines which connect our Lovington and Artesia, New Mexico facilities (our revenue commitments on the intermediate pipelines are discussed above under the HEP IPA). The total consideration was $81.5 million, which consisted of approximately $77.7 million in cash, 70,000 common units of HEP and a capital account credit to maintain our existing general partner interest in HEP. HEP financed the $77.7 million cash portion of the consideration for the intermediate pipelines with the proceeds raised from the private sale, which closed simultaneously with the acquisition, of 1.1 million of its common units for $45.1 million to a limited number of institutional investors and the offering, completed in June 2005, of an additional $35.0 million in principal amount of HEP Senior Notes. As a result of this transaction, our ownership interest in HEP was reduced to the current 45%, including the 2% general partner interest.

HEP is a variable interest entity (VIE) as defined under FIN 46, and following HEP s acquisition of the intermediate feedstock pipelines, we have determined that our beneficial variable interest in HEP was less than 50%; therefore, as required by FIN 46, we deconsolidated HEP effective as of July 1, 2005. The deconsolidation was presented from July 1, 2005 forward, and our share of the earnings of HEP, including any incentive distributions paid through our general partner interest, is now reported using the equity method of accounting. HEP has risk associated with its operations. HEP has three major customers, of which we are one. If any of the customers fails to meet the desired shipping levels or terminates its contracts, HEP could suffer substantial losses unless a new customer is found. If HEP does suffer losses, we would recognize our percentage of those losses based on our ownership percentage in HEP at that time.

As of July 1, 2005, the impact of deconsolidation of HEP was an increase in the liability account of investments in HEP of $83.8 million, a decrease in property, plant and equipment of $157.8 million, a decrease in cash of $20.4 million, a decrease in other current assets of $3.6 million, a decrease in transportation agreements of $62.7 million, a decrease in other assets of $4.5 million, a decrease in minority interest of $179.5 million, a decrease in current liabilities of $3.9 million and a decrease in other long-term liabilities of $149.4 million.

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The HEP Senior Notes are not recorded on our accompanying consolidated balance sheets due to the deconsolidation of HEP effective July 1, 2005. Navajo Pipeline Co., L.P., one of our subsidiaries, has agreed to indemnify HEP s general partner to the extent it makes any payment in satisfaction of $35.0 million of the principal amount of the HEP Senior Notes.

We hold 7,000,000 subordinated units and 70,000 common units of HEP as of December 31, 2006. Our rights as holder of subordinated units to receive distributions of cash from HEP are subordinated to the rights of the common unitholders to receive such distributions.

In addition to the intermediate feedstock pipelines acquired by HEP in July 2005, we contributed all of the initial assets of HEP. As these transactions were among entities under common control, the assets were recorded at historical cost by HEP and we did not recognize a gain on the initial contribution or the intermediate pipelines transaction. The intermediate pipelines transaction resulted in a payment to us from HEP of $71.9 million in excess of our historical basis. Since the historical basis was less than the cash received on the transactions, our investment in HEP is a negative investment. The investment balance was eliminated in consolidation until the deconsolidation of HEP on July 1, 2005.

The following table sets forth the changes in our investment account balance with HEP for the years ended December 31, 2006 and 2005 (In thousands):

Our historic basis in the net assets contributed to or acquired by HEP	$ 45,982
Distributions received for the net assets contributed to or acquired by HEP	(203,263)
General partner capital contributions subsequent to HEP s formation	1,591
Equity in the earnings of HEP subsequent to its formation	18,458
Regular quarterly distributions from HEP	(19,794)
Investment in HEP balance at December 31, 2005	$ (157,026)
Equity in the earnings of HEP	12,929
Regular quarterly distributions from HEP	(20,308)
Investment in HEP balance at December 31, 2006	$ (164,405)

The following tables provide summary financial results for HEP subsequent to its formation on July 13, 2004.

	December 31, 2006	December 31, 2005
	(In thousands)	
Current assets	$ 23,624	$ 28,705
Properties and equipment, net	160,484	162,298
Transportation agreements and other	59,465	63,772
Total assets	$ 243,573	$ 254,775
Current liabilities	$ 14,174	$ 9,251
Long-term liabilities	182,210	181,711
Minority interest	10,963	11,753
Partners equity	36,226	52,060
Total liabilities and partners equity	$ 243,573	$ 254,775

	Years Ended December 31, 2006	2005	2004
		(In thousands)	
Revenues	$ 89,194	$ 80,120	$ 28,182
Operating costs and expenses	48,814	43,580	15,204
Operating income	40,380	36,540	12,978
Other expenses, net	(12,837)	(9,724)	(1,588)
Net income	$ 27,543	$ 26,816	$ 11,390

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We have related party transactions with HEP for pipeline and terminal expenses, certain employee costs, insurance costs and administrative costs under the HEP PTA, HEP IPA and an Omnibus Agreement.

Pipeline and terminal expenses paid to HEP were $52.9 million, $44.2 million and $17.9 million for the years ended December 31, 2006, 2005 and 2004, respectively.

We charged HEP $2.0 million for the years ended December 31, 2006 and 2005 and $0.9 million for the year ended December 31, 2004 for general and administrative services under the Omnibus Agreement which we recorded as a reduction in expenses.

HEP reimbursed us for costs of employees supporting their operations of $7.7 million, $6.5 million and $2.2 million for the years ended December 31, 2006, 2005 and 2004, respectively, which we recorded as a reduction in expenses.

We reimbursed HEP $0.2 million for the years ended December 31, 2006 and 2005 for certain costs paid on our behalf. HEP reimbursed us $3.9 million for the year ended 2004 for certain formation, debt issuance and other costs paid on their behalf.

We received as regular distributions on our subordinated units, common units and general partner interest, $20.3 million, $16.5 million and $3.2 million for the years ended December 31, 2006, 2005 and 2004, respectively. Our distributions for the three years ended December 31, 2006, 2005 and 2004 included $1.2 million, $0.2 million and zero, respectively, in incentive distributions with respect to our general partner interest.

We had a related party receivable from HEP of $2.2 million and $1.4 million at December 31, 2006 and 2005, respectively.

We had accounts payable to HEP of $5.7 million and $5.0 million at December 31, 2006 and 2005, respectively.

Prepayments and other includes $0.2 million and $1.0 million at December 31, 2006 and 2005, respectively, related to minimum payments under the HEP IPA which may be applied as credits against future billings from HEP if our shipments exceed the minimum volume commitments on the intermediate pipelines. In 2006, we expensed $2.2 million related to shortfall payments that we do not expect to recover as credits against future billings.

NOTE 4: Earnings Per Share

Basic earnings per share from continuing operations is calculated as income from continuing operations divided by the average number of shares of common stock outstanding. Diluted earnings per share from continuing operations assumes, when dilutive, the issuance of the net incremental shares from stock options and variable performance shares. The average number of shares of common stock outstanding and per share amounts have been adjusted to reflect the two-for-one stock split effective June 1, 2006. The following is a reconciliation of the denominators of the basic and diluted per share computations for income from continuing operations:

	Years Ended December 31,		
	2006	**2005**	**2004**
	(In thousands, except per share data)		
Income from continuing operations	$ 246,898	$ 164,026	$ 82,944
Average number of shares of common stock outstanding	56,976	61,728	62,780
Effect of dilutive stock options and variable restricted shares	1,234	1,516	1,560

Average number of shares of common stock outstanding assuming dilution	58,210	63,244	64,340
Basic earnings per share from continuing operations	$ 4.33	$ 2.66	$ 1.32
Diluted earnings per share from continuing operations	$ 4.24	$ 2.59	$ 1.29

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NOTE 5: Stock-Based Compensation

On December 31, 2006, we had three principal share-based compensation plans, which are described below. The compensation cost that has been charged against income for these plans was $21.2 million, $7.6 million and 11.8 million for the years ended December 31, 2006, 2005 and 2004, respectively. No compensation cost was recorded during 2004 related to the stock options as the stock options were being measured in accordance with the provisions of APB Opinion No. 25 and related interpretations. The total income tax benefit recognized in the income statement for share-based compensation arrangements was $7.6 million, $3.0 million and 4.6 million for the years ended December 31, 2006, 2005 and 2004, respectively. It is currently our practice to issue new shares for settlement of option exercises, restricted stock grants or performance share units settled in stock. Our current accounting policy for the recognition of compensation expense for awards with pro-rata vesting (substantially all of our awards) is to expense the costs pro-rata over the vesting periods, which results in a higher expense in the earlier periods of the grants. At December 31, 2006, 2,642,174 shares of common stock were reserved for future grants under the current long-term incentive compensation plan, which reservation allows for awards of options, restricted stock, or other performance awards.

Previously awarded stock options and all other compensation arrangements based on the market value of our common stock have been adjusted to reflect the two-for-one stock splits effective June 1, 2006 and August 30, 2004.

Stock Options

Under our Long-Term Incentive Compensation Plan and a previous stock option plan, we have granted stock options to certain officers and other key employees. All the options have been granted at prices equal to the market value of the shares at the time of the grant and normally expire on the tenth anniversary of the grant date. These awards generally vest 20% at the end of each of the five years after the grant date. There have been no options granted since December 2001. The fair value of each option awarded has been estimated using the Black-Scholes option pricing model.

A summary of option activity as of December 31, 2006, and changes during the year ended December 31, 2006 is presented below:

Options	Shares	Weighted Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value ($000)
Outstanding at January 1, 2006	2,479,500	$ 2.50		
Exercised	(902,700)	$ 2.93		
Forfeited or expired				
Outstanding at December 31, 2006	1,576,800	$ 2.25	3.2	$ 77,500
Exercisable at December 31, 2006	1,576,800	$ 2.25	3.2	$ 77,500

The total intrinsic value of options exercised during the years ended December 31, 2006, 2005 and 2004, was $30.9 million, $14.9 million and $14.3 million, respectively.

A summary of the status of our nonvested options as of December 31, 2006 and changes during the year ended December 31, 2006, is presented below:

Nonvested Options	Options	Weighted-Average Grant-Date Fair Value
Nonvested at January 1, 2006	408,800	$ 1.02

Vested	(408,800)	$ 1.02
Forfeited		
Nonvested at December 31, 2006		

As of December 31, 2006, all stock options granted were fully vested. The total fair value of options vested during the years ended December 31, 2006, 2005 and 2004, was $0.4 million, $0.5 million and $0.8 million, respectively.
Cash received from option exercises under the stock option plans for the years ended December 31, 2006, 2005 and 2004, was $2.6 million, $2.8 million and $4.7 million, respectively. The actual tax benefit realized for the tax deductions from option exercises under the stock option plans totaled $12.0 million, $5.8 million and $5.6 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Restricted Stock

Under our Long-Term Incentive Compensation Plan, we grant certain officers, other key employees and outside directors restricted stock awards with substantially all awards vesting generally over a period of one to five years. Although ownership of the shares does not transfer to the recipients until after the shares vest, recipients have dividend rights on these shares from the date of grant. The vesting for certain key executives is contingent upon certain earnings per share targets being realized. The fair value of each share of restricted stock awarded, including the shares issued to the key executives, was measured based on the market price as of the date of grant and is being amortized over the respective vesting period.
A summary of restricted stock activity as of December 31, 2006, and changes during the year ended December 31, 2006 is presented below:

Restricted Stock	Grants	Weighted Average Grant-Date Fair Value	Aggregate Intrinsic Value ($000)
Outstanding at January 1, 2006 (not vested)	545,808	$ 9.85	
Vesting and transfer of ownership to recipients	(148,900)	$ 6.81	
Granted	102,998	$ 30.91	
Forfeited	(4,984)	$ 17.06	
Outstanding at December 31, 2006 (not vested)	494,922	$ 15.07	$ 25,439

The total intrinsic value of restricted stock vested and transferred to recipients during the years ended December 31, 2006, 2005 and 2004 were $5.5 million, $2.5 million and zero, respectively. As of December 31, 2006, there was $2.7 million of total unrecognized compensation cost related to nonvested restricted stock grants. That cost is expected to be recognized over a weighted-average period of 1.2 years. The total fair value of shares vested during the year ended December 31, 2006 was $1.0 million.

Performance Share Units

Under our Long-Term Incentive Compensation Plan, we grant certain officers and other key employees performance share units, some of which are payable in cash and some are payable in stock upon meeting certain criteria over the service period, and generally vest over a period of one to three years.
During the 2006 first quarter, certain grantees agreed to amend their outstanding performance share units to provide for the settlement in the form of our common stock instead of cash. The performance criteria of both the amended performance share units and the original performance share units not amended are based upon our share price and upon our total shareholder return during the requisite period as compared to the total shareholder return of our peer group of refining companies (referred to as market performance criteria). In addition, during the 2006 first quarter, we granted new performance share units that will be settled in our common stock based on certain measurements of our financial performance as compared to a select peer group of companies (referred to as financial performance criteria). The fair value of each performance share unit award payable in cash is being revalued quarterly based on our valuation model and the corresponding expense is being amortized over the vesting periods. The fair value of each

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performance share unit award settled in stock is determined at the grant date (or the amendment date in the case of our amended agreements) and the corresponding expense is being amortized over the vesting periods.

The fair value of each performance share unit award based on financial performance criteria was measured based on the grant date stock price at February 16, 2006 of $29.50 (adjusted for the two-for-one stock split effective June 1, 2006) and will apply to the number of shares ultimately issued for each award. The number of shares ultimately issued for each award will be based on our financial performance as compared to peer group companies and can range from zero to 200% of the number of performance share units issued. We currently have estimated the final payout of shares at 150%.

The fair value of each performance share unit award based on market performance criteria is computed based on an expected-cash-flow approach. The analysis utilizes the current stock price, dividend yield, historical total returns as of the measurement date, expected total returns based on a capital asset pricing model methodology, standard deviation of historical returns and comparison of expected total returns with the peer group. The expected total return and historical standard deviation are applied to a lognormal expected return distribution in a Monte Carlo simulation model to identify the expected range of potential returns and probabilities of expected returns.

For the year ended December 31, 2006, this valuation analysis was performed for the performance share units with market based performance on the February 10, 2006 effective date of the amendment of certain awards to provide for settlement in stock rather than cash, and at the end of each quarter of 2006.

At February 10, 2006, the price of our stock was $31.96 (adjusted for the two-for-one stock split effective June 1, 2006), the latest quarterly dividend was $0.05 per share (adjusted for the two-for-one stock split effective June 1, 2006), and the risk-free rates ranged from 4.68% to 4.70%, depending on the remaining performance period. The inputs affecting the range of expected total returns for us and the peer group are based on a capital asset pricing model utilizing information available at each measurement date. The monthly standard deviation of returns is based on the standard deviation of historical return information. The range of expected returns and standard deviation is presented below:

Company	Expected Return on Equity	Standard Deviation (Monthly)
Holly	12.25%	10.9% to 12.1%
Peer group	10.0% to 13.5%	7.9% to 16.0%

At December 31, 2006, the price of our stock was $51.40, the latest quarterly dividend was $0.08 per share, and the risk-free rate was 4.84%. The inputs affecting the range of expected total returns for us and the peer group are based on a capital asset pricing model utilizing information available at each measurement date. The monthly standard deviation of returns is based on the standard deviation of historical return information. The range of expected returns and standard deviation is presented below:

Company	Expected Return on Equity	Standard Deviation (Monthly)
Holly	12.2%	13.4%
Peer group	10.6% to 13.6%	10.5% to 14.4%

A summary of performance share units activity as of December 31, 2006, and changes during the year ended December 31, 2006 is presented below:

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Performance Share Units	Market Performance Payable in Cash Grants	Market Performance Stock Settled Grants	Financial Performance Stock Settled Grants	Total Performance Share Units
Outstanding at January 1, 2006 (nonvested)	356,524			356,524
Amended to settle in stock	(128,574)	128,574		
Vesting and payment of benefit to recipients				
Granted			75,984	75,984
Forfeited	(600)	(2,800)	(1,056)	(4,456)
Outstanding at December 31, 2006 (nonvested)	227,350	125,774	74,928	428,052

There was no cash paid during the years ended December 31, 2006 and 2004 related to vested performance share units, while $6.3 million was paid during the year ended December 31, 2005 related to vested performance units. As of December 31, 2006, the cash liability associated with these awards was $19.4 million and is recorded in Accrued liabilities in our consolidated balance sheets. Based on the weighted average fair value at December 31, 2006 of $67.68, there was $4.9 million of total unrecognized compensation cost related to nonvested performance share units. That cost is expected to be recognized over a weighted-average period of 0.8 years.

Upon early adoption of SFAS No. 123 (revised), effective July 1, 2005, we recorded a cumulative effect of a change in accounting principle relating to our performance units, due to the initial effect of measuring these awards at fair value, where previously they were measured at intrinsic value. The total cumulative effect of the change in accounting principle recorded upon adoption was a gain of $0.7 million, net of deferred tax expense of $0.4 million.

The following table represents the effect on net income and earnings per share as if we had applied the fair value based method and recognition provisions of SFAS No. 123 to stock based employee compensation in the year ended December 31, 2004 (adjusted for the two-for-one stock split effective June 1, 2006).

	Year Ended December 31, 2004 (In thousands,except per share data)
Net income, as reported	$ 83,879
Deduct: Total stock-based employee compensation expense determined under the fair value method for stock option awards, net of related tax effects	371
Pro-forma net income	$ 83,508
Net income per share basic	
As reported	$ 1.34
Pro-forma	$ 1.33
Net income per share diluted	
As reported	$ 1.30
Pro-forma	$ 1.30

NOTE 6: Cash and Cash Equivalents and Investments in Marketable Securities

Our investment portfolio consists of cash, cash equivalents, and investments in debt securities primarily issued by government entities. In addition, as part of the sale of the Montana Refinery, we received 1,000,000 shares of Connacher common stock.

We invest in highly-rated marketable debt securities, primarily issued by government entities that have maturities at the date of purchase of greater than three months. These securities include investments in variable rate demand notes (VRDN) and auction rate securities (ARS). Although VRDN and ARS may have long-term stated maturities, generally 15 to 30 years, we have designated these securities as available-for-sale and have classified them as current because we view them as available to support our current operations. Rates on VRDN are typically reset either daily or weekly. Rates on ARS are reset through a Dutch auction process at intervals between 35 and 90 days, depending on the terms of the security. VRDN and ARS may be liquidated at par on the rate reset date. We also invest in other marketable debt securities with the maximum maturity of any individual issue not greater than two years from the date of purchase. All of these instruments are classified as available-for-sale, and as a result, are reported at fair value. Interest income is recorded as earned. Unrealized gains and losses, net of related income taxes, are temporary and reported as a component of accumulated other comprehensive income. Upon sale, realized gains and losses on the sale of marketable securities are computed based on the specific identification of the underlying cost of the securities sold and the unrealized gains and losses previously reported in other comprehensive income are reclassified to current earnings.

The following is a summary of our available-for-sale securities at December 31, 2006:

	Available-for-Sale Securities		
	Amortized Cost	Gross Unrealized Losses	Estimated Fair Value (Net Carrying Amount)
		(In thousands)	
States and political subdivisions	$ 98,910	$ (64)	$ 98,846
Equity securities	4,328	(1,338)	2,990
Total marketable securities	$ 103,238	$ (1,402)	$ 101,836

Interest income on our marketable debt securities for the year ended December 31, 2006 included $5.6 million of interest earned, $0.1 million in realized losses and amortization of $1.5 million in net premiums paid related to our marketable debt securities. We had 267 sales and maturities during 2006 in which we received a total of $319.3 million. The realized losses represent the difference between the purchase price, as amortized, and market value on the maturity or sales date.

The following is a summary of our available-for-sale securities at December 31, 2005:

	Available-for-Sale Securities		
	Amortized Cost	Gross Unrealized Losses	Estimated Fair Value (Net Carrying Amount)
		(In thousands)	
States and political subdivisions	$ 205,514	$ (491)	$ 205,023
Corporate debt securities	755		755
Total marketable securities	$ 206,269	$ (491)	$ 205,778

Interest income on our marketable debt securities for the year ended December 31, 2005 included $5.9 million of interest earned, $0.3 million in realized losses and amortization of $1.4 million in net premiums paid related to our marketable debt securities. We had 220 sales and maturities during 2005 in which we received a total of $268.0 million. The realized losses represent the difference between the purchase price, as amortized, and market value on the maturity or sales date.

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NOTE 7: Inventories

	December 31, 2006	December 31, 2005
	(In thousands)	
Crude oil	$ 25,644	$ 25,483
Other raw materials and unfinished products [1]	14,905	8,567
Finished products [2]	73,596	57,207
Process chemicals [3]	6,053	5,263
Repairs and maintenance supplies and other	9,477	6,819
	$ 129,675	$ 103,339

(1) Other raw materials and unfinished products include feedstocks and blendstocks, other than crude. The inventory carrying value includes the cost of the raw materials and transportation.

(2) Finished products include gasolines, jet fuels, diesels, asphalts, LPG s and residual fuels. The inventory carrying value includes the cost of raw materials including transportation and direct production costs.

(3) Process chemicals include

catalysts, additives and other chemicals. The inventory carrying value includes the cost of the purchased chemicals and related freight.

The excess of current cost over the LIFO value of inventory was $136.6 million and $139.4 million at December 31, 2006 and 2005, respectively. We recognized $4.2 million and $3.0 million in income from continuing operations in the years ended December 31, 2006 and 2005, respectively, resulting from liquidations of certain LIFO inventory quantities that were carried at lower costs as compared to current costs.

Inventories are stated at the lower of cost, using the LIFO method for crude oil and refined products and the average cost method for materials and supplies, or market. Cost is determined using the LIFO inventory valuation methodology and market is determined using current estimated selling prices. Under the LIFO method, the most recently incurred costs are charged to cost of sales and inventories are valued at the earliest acquisition costs. In periods of rapidly declining prices, LIFO inventories may have to be written down to market due to the higher costs assigned to LIFO layers in prior periods. In addition, the use of the LIFO inventory method may result in increases or decreases to cost of sales in years that inventory volumes decline as the result of charging cost of sales with LIFO inventory costs generated in prior periods.

NOTE 8: Properties, Plants and Equipment

	December 31,	
	2006	**2005**
	(In thousands)	
Land, buildings and improvements	$ 22,931	$ 15,113
Refining facilities	467,923	325,627
Pipelines and terminals	63,183	49,777
Transportation vehicles	21,491	18,144
Oil and gas exploration and development	3,633	3,638
Other fixed assets	17,107	15,902
Construction in progress	46,472	104,440
	642,740	532,641
Accumulated depreciation, depletion and amortization	(237,270)	(216,502)
	$ 405,470	$ 316,139

We did not capitalize any interest for the years ended December 31, 2006 and 2005.

NOTE 9: Investments in Joint Ventures

Prior to February 2005, NK Asphalt Partners was owned 49% by us and 51% by a subsidiary of Koch and did business under the name Koch Asphalt Solutions Southwest. We accounted for this investment using the equity method. In February 2005, we purchased the 51% interest in NK Asphalt Partners owned by Koch for $16.9 million plus working capital. This purchase increased our ownership in NK Asphalt Partners from 49% to 100% and eliminated any further obligations we had with respect to additional contributions under the joint venture agreement. The partnership manufactures and markets asphalt and asphalt products from various terminals in Arizona and New Mexico and now does business under the name Holly Asphalt Company. From the date of acquisition of the additional 51%, we have consolidated the results of NK Asphalt Partners in our consolidated financial statements. All intercompany transactions have been eliminated in consolidation. The purchase price was allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. The total purchase consideration for the 51% interest, including expenses, was $21.8 million, less cash of $3.4 million which was recorded due to the consolidation of NK Asphalt Partners at the time of the 51% acquisition. In addition to the cash, at the date of the acquisition, we recorded current assets of $11.7 million, net property, plant and equipment of $20.4 million, intangible assets of $5.2 million, goodwill of $1.0 million, and current liabilities of $8.5 million and eliminated our equity investment. Sales to the joint venture during 2005, prior to the acquisition, were $3.9 million and $32.2 million during the year ended December 31, 2004.

Prior to February 28, 2005, we had a 49% interest in MRC Hi-Noon LLC, a joint venture operating retail service stations and convenience stores in Montana, and we accounted for our share of earnings from the joint venture using the equity method. At December 31, 2004, we had a reserve balance of approximately $0.8 million related to the collectability of advances to the joint venture and related accrued interest. On February 28, 2005, we sold our 49% interest to our joint venture partner and agreed to accept partial payment on the advances we previously made to the joint venture. In connection with this transaction, we received $0.8 million, which resulted in a book gain to us of $0.5 million.

NOTE 10: Environmental Costs

Consistent with our accounting policy for environmental remediation costs, we expensed $5.6 million, $0.5 million and $0.8 million for the years ended December 31, 2006, 2005 and 2004, respectively, for environmental remediation obligations. The accrued environmental liability reflected in the consolidated balance sheet was $7.6 million and $3.1 million at December 31, 2006 and 2005, respectively, of which $6.1 million and $2.0 million, respectively, was classified as other long-term liabilities. Costs of future expenditures for environmental remediation are not discounted to their present value.

NOTE 11: Debt

Credit Facility

On July 1, 2004, we entered into a $175.0 million secured revolving credit facility with Bank of America as administrative agent and lender, with a term of four years and an option to increase the facility to $225.0 million subject to certain conditions. The credit facility may be used to fund working capital requirements, capital expenditures, acquisitions or other general corporate purposes. Interest on the borrowings is based upon, at our option, (i) the Eurodollar rate plus an applicable rate ranging from 1.25% to 2.50% per annum for each Eurodollar loan and (ii) the base rate plus an applicable rate ranging from 0.00% to 1.25% per annum for each base rate loan. A fee ranging from 1.25% to 2.50% per annum is payable on the outstanding balance of all letters of credit and a commitment fee ranging from 0.30% to 0.50% per annum is payable on the unused portion of the facility. Such interest rate margins and fees are determined based on a quarterly calculation of the ratio of our debt to EBITDA. The borrowing base, which secures the facility, consists of accounts receivable and inventory, and at our option, pledged cash and cash equivalents. The credit facility imposes usual and customary requirements for this type of credit facility, including: (i) maintenance of certain levels of consolidated tangible net worth, interest coverage and leverage ratios; (ii) limitations on liens, investments, indebtedness and dividends; and (iii) a prohibition on changes in control. We were in compliance with all covenants at December 31, 2006. At December 31, 2006, we had

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outstanding letters of credit totaling $2.3 million, and no outstanding borrowings under our credit facility. At that level of usage, the unused commitment under our current credit facility was $172.7 million at December 31, 2006.
We made cash interest payments of $0.5 million, $2.0 million and $2.7 million for the years ended December 31, 2006, 2005 and 2004, respectively.

HEP Debt

As HEP is no longer consolidated in our financial statements effective July 1, 2005 (see Note 3), we no longer include the debt of HEP in our consolidated financial statements.

NOTE 12: Income Taxes

The provision for income taxes from continuing operations is comprised of the following:

	Years Ended December 31,		
	2006	2005	2004
		(In thousands)	
Current			
Federal	$ 105,469	$ 89,685	$ 65,335
State	20,712	15,648	13,730
Deferred			
Federal	9,490	(4,224)	(20,485)
State	932	(1,483)	(4,595)
	$ 136,603	$ 99,626	$ 53,985

The statutory federal income tax rate applied to pre-tax book income from continuing operations reconciles to income tax expense as follows:

	Years Ended December 31,		
	2006	2005	2004
		(In thousands)	
Tax computed at statutory rate	$ 134,225	$ 92,279	$ 47,925
State income taxes, net of federal tax benefit	14,957	10,282	5,340
Federal tax credits	(10,776)		
Other	(1,803)	(2,935)	720
	$ 136,603	$ 99,626	$ 53,985

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Our deferred income tax assets and liabilities for continuing operations as of December 31, 2006 and 2005 are as follows:

	December 31, 2006		
	Assets	Liabilities	Total
		(In thousands)	
Deferred taxes			
Accrued employee benefits	$ 13,499	$ (29)	$ 13,470
Accrued postretirement benefits	196	(1,947)	(1,751)
Accrued environmental costs	731		731
Inventory differences	247	(4,858)	(4,611)
Deferred turnaround costs		(848)	(848)
Prepayments and other	1,343	(5,441)	(4,098)

Total current	16,016	(13,123)	2,893
Properties, plants and equipment (due primarily to tax in excess of book depreciation)		(71,181)	(71,181)

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	December 31, 2006		
	Assets	Liabilities	Total
		(In thousands)	
Accrued postretirement benefits	5,375	(838)	4,537
Accrued environmental costs	2,244		2,244
Deferred turnaround costs		(3,022)	(3,022)
Investments in HEP	41,724		41,724
Other	6,259	(1,337)	4,922
Total noncurrent	55,602	(76,378)	(20,776)
Total	$ 71,618	$ (89,501)	$ (17,883)

	December 31, 2005		
	Assets	Liabilities	Total
		(In thousands)	
Deferred taxes			
Accrued employee benefits	$ 4,218	$ (30)	$ 4,188
Accrued postretirement benefits	143	(1,337)	(1,194)
Accrued environmental costs	418		418
Inventory differences	634	(3,041)	(2,407)
Deferred turnaround costs		(2,391)	(2,391)
Prepayments and other	729	(990)	(261)
Total current	6,142	(7,789)	(1,647)
Properties, plants and equipment (due primarily to tax in excess of book depreciation)		(57,648)	(57,648)
Accrued postretirement benefits	6,649		6,649
Accrued environmental costs	782		782
Deferred turnaround costs		(2,811)	(2,811)
Investments in HEP	39,803	(376)	39,427
Other	4,482	(870)	3,612
Total noncurrent	51,716	(61,705)	(9,989)
Total	$ 57,858	$ (69,494)	$ (11,636)

We made income tax payments of $142.9 million in 2006, $87.8 million in 2005 and $72.7 million in 2004.

NOTE 13: Stockholders Equity

The following table shows our common shares outstanding and the activity during the year:

	Years Ended December 31,		
	2006	2005	2004
Common shares outstanding at beginning of year	58,752,942	62,589,520	62,056,112
Issuance of common stock upon exercise of stock options	902,700	981,300	1,883,200
	51,952	58,100	217,508

Issuance of restricted stock, excluding restricted stock with performance Feature			
Vesting of restricted stock with performance feature	119,000	119,000	
Forfeitures of restricted stock	(4,984)	(10,700)	(34,700)
Purchase of treasury stock	(4,504,995)	(5,099,594)	(1,532,600)
Sale of treasury stock		115,316	
Common shares outstanding at end of year	55,316,615	58,752,942	62,589,520

The common shares outstanding in the above table reflect the June 1, 2006 and August 30, 2004 two-for-one stock splits as discussed below.

Two-For-One Stock Splits: On May 11, 2006, we announced that our Board of Directors approved a two-for-one stock split payable in the form of a stock dividend of one share of common stock for each issued and outstanding share of common stock. The stock dividend was paid on June 1, 2006 to all holders of record of common stock at the close of business on May 22, 2006.

On August 2, 2004, we announced that our Board of Directors approved a two-for-one stock split payable in the form of a stock dividend of one share of common stock for each issued and outstanding share of common stock.

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The stock dividend was paid on August 30, 2004 to all record holders of common stock at the close of business on August 16, 2004.

All references to the number of shares of common stock (other than authorized shares and other than issued shares and treasury shares at December 31, 2005 shown on our Consolidated Balance Sheets) and per share amounts for all periods presented have been adjusted to reflect the split on a retrospective basis.

Common Stock Repurchases: On November 7, 2005, we announced that our Board of Directors authorized the repurchase of up to $200.0 million of our common stock. Subsequently, in October 2006 our Board of Directors authorized a $100.0 million increase to our $200.0 million common stock repurchase program increasing the authorized stock repurchase limit from $200.0 million to $300.0 million. Repurchases are being made from time to time in the open market or privately negotiated transactions based on market conditions, securities law limitations and other factors. During 2006, we repurchased 4,459,000 shares at a cost of $177.0 million or an average of $39.70 per share under this repurchase initiative. From inception of this plan through December 31, 2006, we repurchased 5,446,000 shares at a cost of $207.0 million or an average of $38.00 per share under this repurchase initiative.

On May 19, 2005, we announced that our Board of Directors authorized the repurchase of up to $100.0 million of our common stock. Repurchases were made from time to time in the open market or privately negotiated transactions based on market conditions, securities law limitations and other factors. From inception of this plan through December 31, 2005, we repurchased 4,062,414 shares (adjusted for the two-for-one stock split effective June 1, 2006) at a cost of $100.0 million or an average of $24.62 per share (adjusted for the two-for-one stock split effective June 1, 2006) under this repurchase initiative. This program was completed in October 2005.

During the year ended December 31, 2006, we repurchased at market price from certain executives 46,388 shares of our common stock at a cost of $1.4 million; these purchases were made under the terms of restricted stock agreements to provide funds for the payment of payroll and income taxes due at the vesting of restricted shares in the case of executives who did not elect to satisfy such taxes by other means.

NOTE 14: Other Comprehensive Income

The components and allocated tax effects of other comprehensive income (loss) are as follows:

	Before-Tax	Tax Expense (Benefit) (In thousands)	After-Tax
For the year ended December 31, 2006			
Minimum pension liability adjustment	$ 5,542	$ 2,156	$ 3,386
Unrealized loss on available-for-sale securities	(908)	(353)	(555)
Other comprehensive loss	$ 4,634	$ 1,803	$ 2,831
For the year ended December 31, 2005			
Minimum pension liability adjustment	$ (4,973)	$ (1,934)	$ (3,039)
Unrealized loss on available-for-sale securities	(72)	(28)	(44)
Other comprehensive loss	$ (5,045)	$ (1,962)	$ (3,083)
For the year ended December 31, 2004			
Minimum pension liability adjustment	$ (2,006)	$ (783)	$ (1,223)
Unrealized loss on available-for-sale securities	(419)	(162)	(257)
Hedging activities	(599)	(230)	(369)

Other comprehensive loss	$	(3,024)	$	(1,175)	$	(1,849)

The temporary unrealized loss on securities available-for-sale is due to changes in the market prices of securities. Accumulated other comprehensive loss in the equity section of the balance sheet includes:

	December 31, 2006	2005
	(In thousands)	
Pension obligation adjustment	$ (1,115)	$ (4,501)
Unrealized loss on securities available-for-sale	(856)	(301)
Adjustment to initially apply adoption of SFAS No. 158, net of income tax effect of $5,977	(9,387)	
Accumulated other comprehensive loss	$ (11,358)	$ (4,802)

NOTE 15: Retirement Plans

Retirement Plan: We have a non-contributory defined benefit retirement plan that covers substantially all employees. Our policy is to make contributions annually of not less than the minimum funding requirements of the Employee Retirement Income Security Act of 1974. Benefits are based on the employee s years of service and compensation. We adopted SFAS No. 158, effective as of December 31, 2006, which required us to recognize the under-funded status of our defined benefit retirement plan as a liability in our consolidated balance sheets, with the change in our funded status recorded as a component of other comprehensive income. Accordingly, the amounts presented in the tables below for 2006 and 2005 utilize different accounting methodologies.

The following table sets forth the changes in the benefit obligation and plan assets of our retirement plan for the years ended December 31, 2006 and 2005:

	Year Ended December 31, 2006	2005
	(In thousands)	
Change in plan s benefit obligation		
Pension plan s benefit obligation beginning of year	$ 68,776	$ 59,300
Service cost	4,270	3,630
Interest cost	4,133	3,790
Benefits paid	(10,190)	(5,231)
Actuarial gain (loss)	(4,150)	7,074
Acquisitions (divestitures)	(732)	213
Pension plan s benefit obligation end of year	62,107	68,776
Change in pension plan assets		
Fair value of plan assets beginning of year	42,642	35,209
Actual return on plan assets	4,962	2,664
Benefits paid	(10,190)	(5,231)
Employer contributions	13,000	10,000
Fair value of plan assets end of year	50,414	42,642
Reconciliation of funded status		
Under-funded balance	(11,693)	(26,134)
Unrecognized prior service cost	N/A	3,208
Unrecognized net loss	N/A	22,079
Net under-funded status	$ (11,693)	$ (847)

Amounts recognized in consolidated balance sheets		
Intangibles and other assets	$ N/A	$ 3,208
Accrued pension liability	N/A	(10,114)
Other long-term liability	(11,693)	N/A
Accumulated other comprehensive income	N/A	6,059
Accrued pension liability (net amount recognized)	$ (11,693)	$ (847)

Amounts recognized in accumulated other comprehensive loss		
Actuarial loss	$ (11,383)	$ N/A
Prior service cost	(3,981)	N/A
Total	$ (15,364)	$ N/A

The accumulated benefit obligation was $46.8 million and $52.8 million at December 31, 2006 and 2005, respectively. At December 31, 2005, the accumulated benefit obligation exceeded the fair value of plan assets. The measurement dates used for our retirement plan were December 31, 2006 and 2005.
The weighted average assumptions used to determine end of period benefit obligations:

	December 31,	
	2006	**2005**
Discount rate	6.00%	5.75%
Rate of future compensation increases	4.00%	4.00%

Net periodic pension expense consisted of the following components:

	Years Ended December 31		
	2006	**2005**	**2004**
		(In thousands)	
Service cost benefit earned during the year	$ 4,270	$ 3,630	$ 3,042
Interest cost on projected benefit obligations	4,133	3,790	3,520
Expected return on plan assets	(3,473)	(3,163)	(2,882)
Amortization of prior service cost	258	279	261
Amortization of net loss	1,042	956	685
Curtailment loss	663		
Settlement loss	1,589		
Net periodic pension expense	$ 8,482	$ 5,492	$ 4,626

The weighted average assumptions used to determine net periodic benefit expense:

	Year Ended December 31,		
	2006	**2005**	**2004**
		(In thousands)	
Discount rate	6.05%	6.00%	6.25%
Rate of future compensation increases	4.00%	4.00%	4.25%
Expected long-term rate of return on assets	8.50%	8.50%	8.50%

The estimated amounts that will be amortized from accumulated other comprehensive income into net periodic benefit expense in 2007 are as follows:

	(In thousands)
Actuarial loss	$ 423
Prior service cost	341
Total	$ 764

The incremental effect of applying SFAS No. 158 to individual items in our consolidated balance sheets at December 31, 2006 is as follows:

	Before Adoption of	Effect of SFAS No. 158 Adoption	After Adoption of

	SFAS No. 158		SFAS No. 158
		(In thousands)	
Intangibles and other assets	$23,550	$ (3,671)	$ 19,879
Other long-term liabilities	$15,508	$ 11,693	$ 27,201
Accumulated other comprehensive income (loss)	$ 4,006	$ (15,364)	$(11,358)

The asset allocation for our retirement plan at year end, by asset category, follows:

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Asset Category	Target Allocation 2007	Percentage of Plan Assets at Year End December 31, 2006	December 31, 2005
Equity securities	70%	71%	71%
Debt Securities	30%	29%	29%
Total	100%	100%	100%

The investment policy developed for the Holly Corporation Pension Plan (the Plan) has been designed exclusively for the purpose of providing the highest probabilities of delivering benefits to Plan members and beneficiaries. Among the factors considered in developing the investment policy are: the Plans primary investment goal, rate of return objective, investment risk, investment time horizon, role of asset classes and asset allocation.

The most important component of the investment strategy is the asset allocation between the various classes of securities available to the Plan for investment purposes. The current target asset allocation is 70% equity investments and 30% fixed income investments. The equity allocation is well diversified among the investment styles of large capitalization growth, large capitalization value, small capitalization and international. Equity and fixed income fund managers have been selected based on return/risk track records over time.

The expected long-term rate of returns on Plan assets is 8.5% and is based on historical investment returns. The assumed long-term rate of return on equity and fixed income investments is 10% and 5%, respectively, and using the Plan s asset allocation target of 70% equities and 30% fixed income, the overall assumed rate of return on the Plan is 8.5%.

We expect to contribute between zero to $10.0 million to the retirement plan in 2007. Benefit payments, which reflect expected future service, are expected to be paid as follows: $4.1 million in 2007; $5.5 million in 2008; $5.1 million in 2009; $6.1 million in 2010, $7.0 million in 2011 and $44.9 million in 2012-2016.

Retirement Restoration Plan: We adopted an unfunded retirement restoration plan that provides for additional payments from us so that total retirement plan benefits for certain executives will be maintained at the levels provided in the retirement plan before the application of Internal Revenue Code limitations. We expensed $0.8 million, $0.9 million and $0.6 million for the years ended December 31, 2006, 2005 and 2004, respectively, in connection with this plan. The accrued liability reflected in the consolidated balance sheets was $5.3 million and $4.9 million at December 31, 2006 and 2005, respectively. As of December 31, 2006, the projected benefit obligation under this plan was $5.8 million. Benefit payments, which reflect expected future service, are expected to be paid as follows: $1.0 million in 2007; $2.1 million in 2008; $0.5 million in 2009; $0.5 million in 2010; $2.0 million in 2011 and $2.5 million in 2012-2016.

Defined Contribution Plans: We have defined contribution (401(k)) plans that cover substantially all employees. Our contributions are based on employee s compensation and partially match employee contributions. We expensed $1.9 million, $1.4 million and $1.3 million for the years ended December 31, 2006, 2005 and 2004 in connection with these plans.

Postretirement Medical Plans: We adopted an unfunded postretirement medical plan as part of the voluntary early retirement program offered to eligible employees in fiscal 2000. As part of the early retirement program, we agreed to allow retiring employees to continue coverage at a reduced cost under our group medical plans until normal retirement age. The accrued liability reflected in the consolidated balance sheets was $2.1 million and $2.4 million at December 31, 2006 and 2005, respectively, related to this plan.

Additionally, we maintain an unfunded postretirement medical plan whereby certain retirees between the ages of 62 and 65 can receive benefits paid by us. Periodic costs under this plan have historically been insignificant.

As of December 31, 2006, the total accumulated postretirement benefit obligation under our postretirement medical plans was $5.1 million.

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NOTE 16: Derivative Instruments and Hedging Activities

We periodically utilize petroleum commodity futures contracts to reduce our exposure to the price fluctuations associated with crude oil and refined products. Such contracts historically have been used principally to help manage the price risk inherent in purchasing crude oil in advance of the delivery date and as a hedge for fixed-price sales contracts of refined products. We have also utilized commodity price swaps and collar options to help manage the exposure to price volatility relating to forecasted purchases of natural gas. We regularly utilize contracts that provide for the purchase of crude oil and other feedstocks and for the sale of refined products. Certain of these contracts may meet the definition of a derivative instrument in accordance with SFAS No. 133, as amended. We believe these contracts qualify for the normal purchases and normal sales exception under SFAS No. 133, as amended, because deliveries under the contracts will be in quantities expected to be used or sold over a reasonable period of time in the normal course of business. Accordingly, these contracts are designated as normal purchases and normal sales contracts and are not required to be recorded as derivative instruments under SFAS No. 133, as amended.

During 2005, we entered into two different types of hedging transactions, neither of which involved arrangements designated as hedging instruments per the requirements of SFAS No. 133, and therefore all gains and losses were recorded as incurred. The first transaction was entered into in July 2005 and related to our forecasted August 2005 liquidation of 100,000 barrels of crude oil at our Woods Cross Refinery, where our objective was to fix the price of crude oil associated with the liquidation. To affect the hedge, we sold crude oil futures contracts in July 2005 and liquidated the positions in August 2005 matching when the crude oil inventory was slated for production. We recognized a loss of $535,000 on this transaction and recorded it as an increase in cost of products sold. The other type of transaction we have entered into from time to time beginning in July 2005 relates to forecasted sales of diesel fuel from our refineries, where our principal objective is to take advantage of the high margins (or crack spreads, being the difference between the price of diesel fuel and the cost of crude oil) on a portion of our diesel fuel sales. To effect these hedges, we sold heating oil futures (which most closely match diesel fuel pricing) and bought crude oil futures. We have also entered into commodity swap transactions (the terms of which mirror the futures contracts entered into) to effect the same strategy on a portion of these hedges. Our objective is either to liquidate the positions as the crack spreads return to more normalized levels or to hold these positions until the forecasted diesel fuel sales are made, effectively locking in the diesel fuel crack spreads (or margins) at the high levels. Our strategy is to enter into these transactions only when the margins are at historically very high levels and to have no more than 25% of our diesel fuel production hedged at any given time. During 2005, we entered into hedges totaling 1,505,000 barrels covering forecasted diesel fuel sales from November 2005 to February 2006. The positions were fully liquidated during August to November 2005 resulting in a realized gain of $3.2 million, which was recorded as a decrease in cost of products sold.

In October 2003, we entered into price swaps to help manage the exposure to price volatility relating to forecasted purchases of natural gas from December 2003 to March 2004. These transactions were designated as cash flow hedges of forecasted purchases. The contracts to hedge natural gas costs were for 6,000, 500, and 2,000 MMBtu per day for the Navajo Refinery, the previously-owned Montana Refinery, and the Woods Cross Refinery, respectively. The December 2003 contracts resulted in net realized losses of $0.1 million and were recorded into refining operating costs. At December 31, 2003, included in comprehensive income was a gain of $0.6 million, as the values of the outstanding hedges were marked to the current fair value, in accordance with SFAS No. 133. The January to March 2004 contracts resulted in net realized gains of $0.3 million and were recorded as a reduction to refinery operating expenses. There was no ineffective portion of these hedges, and since March 31, 2004, no price swaps have been outstanding.

NOTE 17: Lease Commitments

We lease certain facilities and equipment under operating leases, most of which contain renewal options. At December 31, 2006, the minimum future rental commitments under operating leases having noncancellable lease terms in excess of one year are as follows (in thousands):

2007	$	3,072
2008		2,255
2009		2,020
2010		1,753
2011		1,068
Thereafter		284
Total	$	10,452

Rental expense charged to operations was $2.3 million, $5.1 million and $7.1 million for the years ended December 31, 2006, 2005 and 2004, respectively.

NOTE 18: Contingencies

We have pending proceedings in the United States Court of Appeals for the District of Columbia Circuit with respect to rulings by the FERC in proceedings brought by us and other parties against SFPP. These proceedings relate to tariffs of common carrier pipelines, which are owned and operated by SFPP, for shipments of refined products from El Paso, Texas to Tucson and Phoenix, Arizona and from points in California to points in Arizona. We are one of several refiners that regularly utilize an SFPP pipeline to ship refined products from El Paso, Texas to Tucson and Phoenix, Arizona. Rulings by the FERC relating principally to the period from 1993 through July 2000 resulted in reparations payments from SFPP to us in 2003 totaling approximately $15.3 million. In 2004 the appeals court issued its opinion relating principally to the period from 1993 through July 2000, ruling in favor of our positions on most of the disputed issues that concern us, and remanded the case to the FERC for additional consideration of several issues, some of which are involved in our claims. In May 2005, the FERC issued a general policy statement on an issue concerning the treatment of income taxes in the calculation of allowable rates for pipelines operated by partnerships. The FERC in a later order applied this general policy statement to SFPP and such application is contrary to our position in this case. We and certain other refining companies have pending before the court of appeals petitions challenging the FERC policy on income taxes, decisions by the FERC in 2005 and early 2006 on certain of the remanded issues, and rulings by the FERC on some issues relating to periods after July 2000. In March 2006, SFPP submitted computations asserted to be based on the most recent determinations of the FERC in the case. In April 2006, we filed a protest and comments concerning a number of elements of these computations. One element of the computations, which is based on the FERC s disputed 2005 policy on treatment of income taxes, would if ultimately sustained result in a requirement for us to repay to SFPP approximately $3.0 million of the $15.3 million reparations amount received by us from SFPP in 2003. Because proceedings in the FERC on remand have not been completed and our petitions for review to the court of appeals with respect to the FERC s orders are pending, it is not possible to determine whether the amount of reparations actually due to us for the period from 1993 through July 2000 will be found to be less than or more than the $15.3 million we received in 2003. Although it is not possible at the date of this report to predict the final outcome of these proceedings, we believe that future proceedings are not likely to result in an obligation for us to repay more than the amount now asserted in SFPP s most recent computations (approximately $3.0 million) and that the more likely final result would be either a smaller repayment by us than is now asserted by SFPP or a payment to us of additional reparations. The ultimate amount of reparations payable to us will be determined only after further proceedings in the FERC on issues that have not been finally determined by the FERC, further proceedings in the appeals court with respect to determinations by the FERC, and possibly future petitions by one or more of the parties seeking United States Supreme Court review of issues in the case.

In discussions beginning in the last half of 2005, the EPA and the State of Utah have asserted that we have Federal Clean Air Act liabilities relating to our Woods Cross Refinery because of actions taken or not taken by prior owners of the Woods Cross Refinery, which we purchased from ConocoPhillips in June 2003. We have tentatively agreed with the EPA and the State of Utah to settle the issues presented by means of an agreement similar to the 2001 Consent Agreement we entered into for our Navajo Refinery and previously-owned Montana Refinery. The tentative settlement agreement, which has not yet been put into a final written agreement, includes proposed obligations for us to make specified additional capital investments expected to total up to approximately $10.0 million over several years and to make changes in operating procedures at the refinery. The agreements for the purchase of the Woods Cross Refinery provide that ConocoPhillips will indemnify us, subject to specified limitations, for environmental claims arising from circumstances prior to our purchase of the refinery. We believe that, in the present circumstances, the amount due to us from ConocoPhillips under the agreements for the purchase of the Woods Cross Refinery would be approximately $1.4 million with respect to the tentative settlement.

Our Navajo Refining Company subsidiary is named as a defendant, along with approximately 40 other companies involved in oil refining and marketing and related businesses, in a lawsuit originally filed in May 2006 by the State of New Mexico in the U.S. District Court for the District of New Mexico. The lawsuit, as amended in October 2006 through the filing of a second amended complaint in the U.S. District Court for the Southern District of New York under multidistrict procedures, alleges that the defendants are liable for contaminating the waters of New Mexico through producing and/or supplying MTBE or gasoline or other products containing MTBE. The claims made are for defective design or product, failure to warn, negligence, public nuisance, statutory public nuisance, private nuisance, trespass, and civil conspiracy. The second amended complaint also contains a claim, which is asserted in the complaint only against certain other defendants but which appears to be similar to a claim that has been threatened in a mailing to Navajo by law firms representing the plaintiff in this case, alleging violations of certain provisions of the Toxic Substances Control Act. The lawsuit seeks compensatory damages unspecified in amount, injunctive relief, exemplary and punitive damages, costs, attorney s fees allowed by law, and interest allowed by law. As of the close of business on the day prior to the date of this report, Navajo has not been served in this case. At the date of this report, it is not possible to predict the likely course or outcome of this litigation.

On December 6, 2006, the Montana Department of Environmental Quality (MDEQ) filed in state district court in Great Falls, Montana a Complaint and Application for Preliminary Injunction (the Complaint) naming as defendants Montana Refining Company (MRC), our subsidiary that owned the Great Falls, Montana refinery until it was sold to an unrelated purchaser on March 31, 2006, and the unrelated company that purchased the refinery from MRC. The MDEQ asserts in the Complaint that the Great Falls refinery exceeded limitations on sulfur dioxide in the refinery s air emission permit on certain dates in 2004 and 2005 and in 2006 both before and after the sale of the refinery, erroneously certified compliance with limitations on sulfur dioxide emissions, failed to promptly report emissions limit deviations, exceeded limits on sulfur in fuel gas on specified dates in 2005, failed in 2005 to conduct timely testing for certain emissions, submitted late a report required to be submitted in early 2006, failed to achieve a specified limitation on certain emissions in the first three quarters of 2006, and failed to timely submit a report on a 2005 emissions test. The Complaint seeks penalties under applicable law of up to $10,000 per violation and an order enjoining MRC and the current owner of the refinery from further violations. While we do not agree with a number of the violations asserted in the Complaint, we and the current owner of the Great Falls refinery have been in negotiations with the MDEQ both before and after the filing of the Complaint to attempt to settle the issues raised on a compromise basis. At the date of this report, we are not able to predict the outcome of this matter.

We are a party to various other litigation and proceedings not mentioned in this report which we believe, based on advice of counsel, will not have a materially adverse impact on our financial condition, results of operations or cash flows.

NOTE 19: Segment Information

Our operations are currently organized into one reportable segment, Refining. The Refining segment includes the Navajo Refinery, Woods Cross Refinery and NK Asphalt Partners. Our operations that are not included in the Refining segment include the operations of Holly Corporation, the parent company, and a small-scale oil and gas exploration and production program. Although we previously included the Montana Refinery in the Refining segment, the operating results from the Montana Refinery are now reported in discontinued operations and are not included in the table below.

Prior to our deconsolidation of HEP effective July 1, 2005, our operations were organized into two segments, which were Refining and HEP. These segments have been in effect since July 13, 2004, the closing of the initial public offering of HEP. Our operations that were not included in either the Refining or HEP segments included the operations of Holly Corporation, the parent company, a small-scale oil and gas exploration and production program and the elimination of the revenue and costs associated with HEP s pipeline transportation services for us.

The Refining segment involves the purchase and refining of crude oil and wholesale and branded marketing of refined products, such as gasoline, diesel fuel and jet fuel, and includes our Navajo Refinery and Woods Cross

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Refinery. The petroleum products produced by the Refining segment are marketed in Texas, New Mexico, Arizona, Utah, Wyoming, Idaho, Washington and northern Mexico. The Refining segment also includes certain crude oil pipelines that we own and operate in conjunction with our refining operations as part of the supply networks of the refineries. The Refining segment also includes the equity in earnings from our 49% interest in NK Asphalt Partners prior to February 2005. In February 2005, we acquired the remaining 51% interest in the asphalt joint venture from the other partner; subsequent to the purchase, we include the operations of NK Asphalt Partners in our consolidated financial statements. NK Asphalt Partners, dba Holly Asphalt Company, manufactures and markets asphalt and asphalt products in Arizona, New Mexico, Texas and California. The cost of pipeline transportation and terminal services provided by HEP to us is also included in the Refining segment. The HEP segment involved all of the operations of HEP through June 30, 2005 (prior to the deconsolidation), including approximately 1,300 miles (780 miles prior to the Alon asset acquisition) of pipeline assets principally in Texas, New Mexico and Oklahoma and refined product terminals in several Southwest and Rocky Mountain states. The HEP segment also included a 70% interest in Rio Grande Pipeline Company (Rio Grande), which provides petroleum products transportation. Revenues from the HEP segment were earned through transactions with unaffiliated parties for pipeline transportation, rental and terminalling operations as well as revenues relating to pipeline transportation services provided for our refining operations and from HEP s interest in Rio Grande. Our operations not included in the reportable segment or segments are included in Corporate and Other, including costs of Holly Corporation, the parent company, consisting primarily of general and administrative expenses as well as a small-scale oil and gas exploration and production program. Corporate assets include assets associated with discontinued operations. The consolidations and eliminations column included the elimination of the revenue and costs associated with HEP s pipeline transportation services for us. These items are no longer included after the deconsolidation of HEP effective July 1, 2005.

The accounting policies for the segments, other than our accounting change due to the adoption of SFAS No. 123 (revised) (see Note 5), are the same as those described in the summary of significant accounting policies in Note 1. Our reportable segments prior to July 1, 2005 were strategic business units that offered different products and services.

	Refining	HEP	Corporate and Other	Consolidations and Eliminations	Consolidated Total
			(In thousands)		
Year Ended December 31, 2006					
Sales and other revenues	$4,021,974	$	$ 1,752	$ (509)	$4,023,217
Depreciation and amortization	$ 38,156	$	$ 1,565	$	$ 39,721
Income (loss) from operations	$ 425,474	$	$ (63,583)	$	$ 361,891
Total assets	$ 940,400	$	$297,469	$	$1,237,869
Year Ended December 31, 2005					
Sales and other revenues	$3,028,335	$ 36,034	$ 1,772	$ (19,828)	$3,046,313
Depreciation and amortization	$ 32,993	$ 6,212	$ 1,342	$	$ 40,547
Income (loss) from operations	$ 296,508	$ 16,019	$ (49,786)	$	$ 262,741
Total assets	$ 836,724	$	$306,176	$	$1,142,900
Year Ended December 31, 2004					
Sales and other revenues	$2,104,569	$ 28,182	$ 1,916	$ (18,422)	$2,116,245
Depreciation and amortization	$ 32,785	$ 3,241	$ 1,431	$	$ 37,457
Income (loss) from operations	$ 173,904	$ 12,980	$ (42,907)	$	$ 143,977

Total assets	$ 551,330	$248,157	$103,758	$ 79,468	$ 982,713

NOTE 20: Significant Customers

All revenues were domestic revenues, except for sales of gasoline and diesel fuel for export into Mexico by the Refining segment. The export sales were to an affiliate of PEMEX and accounted for approximately $144.4 million (4%) of our revenues in 2006, $82.0 million (3%) of our revenues in 2005 and $48.7 million (2%) of revenues in

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2004. In 2006 and 2005, we had several significant customers, none of which accounted for more than 10% of our revenues. In 2004, significant sales of greater than 10% of revenues were made to one petroleum company by the Refining segment. This petroleum company accounted for $225.0 million (11%) of revenues in 2004.

NOTE 21: Quarterly Information (Unaudited)

	First Quarter(1)	Second Quarter	Third Quarter	Fourth Quarter	Year
	(In thousands except share data)				
Year Ended December 31, 2006					
Sales and other revenues	$791,594	$1,120,840	$1,172,693	$938,090	$4,023,217
Operating costs and expenses	$749,619	$ 986,615	$1,055,603	$869,489	$3,661,326
Income from operations	$ 41,975	$ 134,225	$ 117,090	$ 68,601	$ 361,891
Income from continuing operations before income taxes	$ 46,647	$ 137,877	$ 123,165	$ 75,812	$ 383,501
Income (loss) from discontinued operations, net of taxes	$ 15,644	$ 5,372	$ (199)	$ (1,149)	$ 19,668
Net income	$ 46,804	$ 93,101	$ 79,002	$ 47,659	$ 266,566
Net income per common share basic	$ 0.80	$ 1.62	$ 1.40	$ 0.86	$ 4.68
Net income per common share diluted	$ 0.78	$ 1.60	$ 1.37	$ 0.84	$ 4.58
Dividends per common share	$ 0.05	$ 0.08	$ 0.08	$ 0.08	$ 0.29
Average number of shares of common stock outstanding					
Basic	58,458	57,186	56,555	55,741	56,976
Diluted	60,028	58,363	57,783	56,965	58,210

	First Quarter(1)(2)	Second Quarter(1)(2)	Third Quarter(1)(2)	Fourth Quarter(1)(2)	Year(1)(2)
	(In thousands except share data)				
Year Ended December 31, 2005					
Sales and other revenues	$624,719	$728,655	$880,520	$812,419	$3,046,313
Operating costs and expenses	$596,600	$642,985	$788,810	$755,177	$2,783,572
Income from operations	$ 28,119	$ 85,670	$ 91,710	$ 57,242	$ 262,741
Income from continuing operations before income taxes	$ 23,456	$ 81,975	$ 95,707	$ 62,514	$ 263,652
Income (loss) from discontinued operations, net of taxes	$ (782)	$ 1,321	$ 1,033	$ 1,391	$ 2,963
Change in accounting principle (net of income tax expense of $426)	$	$	$ 669	$	$ 669
Net income	$ 13,634	$ 52,424	$ 61,719	$ 39,881	$ 167,658
Net income per common share basic	$ 0.22	$ 0.83	$ 1.01	$ 0.67	$ 2.72
	$ 0.21	$ 0.81	$ 0.98	$ 0.65	$ 2.65

Net income per common share diluted					
Dividends per common share	$ 0.04	$ 0.05	$ 0.05	$ 0.05	$ 0.19
Average number of shares of common stock outstanding					
Basic	63,028	63,274	61,236	59,420	61,728
Diluted	64,390	64,718	62,772	60,992	63,244

(1) The average number of shares of common stock and per share amounts have been adjusted to reflect the two-for-one stock split effective June 1, 2006.

(2) On March 31, 2006, we sold our Montana Refinery. Results of operations of the Montana Refinery that were previously reported in operations are now reported in discontinued operations.

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NOTE 22: Subsequent Events

On February 9, 2007 our Board of Directors declared a regular quarterly cash divided of $0.10 per share, payable April 3, 2007 to holders of record on March 22, 2007.

On February 27, 2007, we entered into a definitive agreement with Berry Petroleum Company to purchase black wax crude oil for six years, effective July 1, 2007. We have committed to purchase an initial volume of 3,200 BPD, increasing to 5,000 BPD upon completion of certain capacity expansion projects at our Woods Cross Refinery. Pricing will be calculated at a discount from then-prevailing market rates.

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

We have had no change in, or disagreement with, our independent certified public accountants on matters involving accounting and financial disclosure.

Item 9A. Controls and Procedures

Evaluation of disclosure controls and procedures. Our principal executive officer and principal financial officer have evaluated, as required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (the Exchange Act), our disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of the end of the period covered by this annual report on Form 10-K. Based on that evaluation, the principal executive officer and principal financial officer concluded that the design and operation of our disclosure controls and procedures are effective in ensuring that information we are required to disclose in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms.

Changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Item 9B. Other Information

There have been no events that occurred in the fourth quarter of 2006 that would need to be reported on Form 8-K that have not previously been reported.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by Items 401, 405 and 406 of Regulation S-K in response to this item is set forth in our definitive proxy statement for the annual meeting of stockholders to be held on May 24, 2007 and is incorporated herein by reference.

New York Stock Exchange Certification

In 2006, Matthew P. Clifton, as our Chief Executive Officer, provided to the New York Stock Exchange the annual CEO certification regarding our compliance with the New York Stock Exchange s corporate governance listing standards.

Item 11. Executive Compensation

The information required by Item 402 of Regulation S-K in response to this item is set forth in our definitive proxy statement for the annual meeting of stockholders to be held on May 24, 2007 and is incorporated herein by reference.

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Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The equity compensation plan information required by Item 201(d) and the information required by Item 403 of Regulation S-K in response to this item is set forth in our definitive proxy statement for the annual meeting of stockholders to be held on May 24, 2007 and is incorporated herein by reference.

Item 13. Certain Relationships, Related Transactions and Director Independence

The information required by Item 404 of Regulation S-K in response to this item is set forth in our definitive proxy statement for the annual meeting of stockholders to be held on May 24, 2007 and is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required by Item 9(e) of Schedule 14A in response to this item is set forth in our definitive proxy statement for the annual meeting of stockholders to be held on May 24, 2007 and is incorporated herein by reference.

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PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Documents filed as part of this report

(1) Index to Consolidated Financial Statements

(2) Index to Consolidated Financial Statement Schedules

All schedules are omitted since the required information is not present or is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the consolidated financial statements or notes thereto.

(3) Exhibits

See Index to Exhibits on pages 97 to 100.

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SIGNATURES

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

HOLLY CORPORATION
(Registrant)

/s/ Matthew P. Clifton
Matthew P. Clifton
Chief Executive Officer

Date: February 28, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and as of the date indicated.

Signature	Capacity	Date
	Chairman of Board	
C. Lamar Norsworthy, III		
/s/ Matthew P. Clifton	Chief Executive Officer and Director	February 28, 2007
Matthew P. Clifton		
/s/ P. Dean Ridenour	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 28, 2007
P. Dean Ridenour		
/s/ Stephen J. McDonnell	Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2007
Stephen J. McDonnell		
/s/ W. John Glancy	Senior Vice President, General Counsel and Director	February 28, 2007
W. John Glancy		
/s/ Buford P. Berry	Director	February 28, 2007
Buford P. Berry		
/s/ William J. Gray	Director	February 28, 2007
William J. Gray		

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Signature	Capacity	Date
/s/ Marcus R. Hickerson Marcus R. Hickerson	Director	February 28, 2007
/s/ Robert G. McKenzie Robert G. McKenzie	Director	February 28, 2007
/s/ Thomas K. Matthews, II Thomas K. Matthews, II	Director	February 28, 2007
/s/ Jack P. Reid Jack P. Reid	Director	February 28, 2007
/s/ Paul T. Stoffel Paul T. Stoffel	Director	February 28, 2007

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HOLLY CORPORATION
INDEX TO EXHIBITS
Exhibits are numbered to correspond to the exhibit table
in Item 601 of Regulation S-K)

Exhibit Number	Description
3.1	Restated Certificate of Incorporation of the Registrant, as amended (incorporated by reference to Exhibit 3(a), of Amendment No. 1 dated December 13, 1988 to Registrant s Annual Report on Form 10-K for its fiscal year ended July 31, 1988, File No. 1-3876).
3.2	By-Laws of Holly Corporation as amended and restated December 22, 2005 (incorporated by reference to Exhibit 3.2.2 of Registrant s Current Report on Form 8-K filed December 22, 2005, File No. 1-3876).
4.1	Indenture, dated February 28, 2005, among the Issuers, the Guarantors and the Trustee (incorporated by reference to Exhibit 4.1 of Holly Energy Partners, L.P. s Current Report on Form 8-K filed March 4, 2005, File No. 1-32225).
4.2	Form of 6.25% Senior Note Due 2015 (included as Exhibit A to the Indenture included as Exhibit 4.1 hereto) (incorporated by reference to Exhibit 4.2 of Holly Energy Partners, L.P. s Current Report on Form 8-K filed March 4, 2005, File No. 1-32225).
4.3	Form of Notation of Guarantee (included as Exhibit E to the Indenture included as Exhibit 4.1 hereto) (incorporated by reference to Exhibit 4.3 of Holly Energy Partners, L.P. s Current Report on Form 8-K filed March 4, 2005, File No. 1-32225).
4.4	First Supplemental Indenture, dated March 10, 2005, among Holly Energy Partners, L.P., Holly Energy Finance Corp., the Guarantors identified therein, and U.S. Bank National Association (incorporated by reference to Exhibit 4.5 of Holly Energy Partners, L.P. s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2005, File No. 1-32225).
4.5	Second Supplemental Indenture, dated April 27, 2005, among Holly Energy Partners, L.P., Holly Energy Finance Corp., the Guarantors identified herein, and U.S. Bank National Association (incorporated by reference to Exhibit 4.6 of Holly Energy Partners, L.P. s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2005, File No. 1-32225).
10.1*	Holly Corporation Stock Option Plan As adopted at the Annual Meeting of Stockholders of Holly Corporation on December 13, 1990 (incorporated by reference to Exhibit 4(i) of Registrant s Annual Report on Form 10-K for its fiscal year ended July 31, 1991, File No. 1-3876).
10.2*	Holly Corporation Long-Term Incentive Compensation Plan as amended and restated (Formerly Designated the Holly Corporation 2000 Stock Option Plan) As approved at the Annual Meeting of Stockholders of Holly Corporation on December 12, 2002 (incorporated by reference to Exhibit 10 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended October 31, 2002, File No. 1-3876).
10.3*	Supplemental Payment Agreement, dated as of July 8, 1993, between Lamar Norsworthy and Holly Corporation (incorporated by reference to Exhibit 10(a) of Registrant s Annual Report on Form 10-K for

its fiscal year ended July 31, 1993, File No. 1-3876).

Exhibit Number	Description
10.4*	Holly Corporation Supplemental Payment Agreement for 2001 Service as Director (incorporated by reference to Exhibit 10.19 of Registrant s Annual Report on Form 10-K for its fiscal year ended July 31, 2002, File No. 1-3876).
10.5*	Holly Corporation Supplemental Payment Agreement for 2002 Service as Director (incorporated by reference to Exhibit 10.20 of Registrant s Annual Report on Form 10-K for its fiscal year ended July 31, 2002, File No. 1-3876).
10.6*	Holly Corporation Supplemental Payment Agreement for 2003 Service as Director (incorporated by reference to Exhibit 10.2 of Registrant s Quarterly Report on Form 10-Q for the quarterly period ended January 31, 2003, File No. 1-3876).
10.7*	First Amendment to the Holly Corporation Long-Term Incentive Compensation Plan, as amended and restated (formerly designated the Holly Corporation 2000 Stock Option Plan) (incorporated by reference to Exhibit 10.1 of Registrant s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2005, File No. 1-3876).
10.8*	Form of Director Restricted Stock Agreement (incorporated by reference to Exhibit 10.1 of Registrant s Current Report on Form 8-K filed November 4, 2004, File No. 1-3876).
10.9*	Form of Executive Restricted Stock Agreement [two-year term vesting form] (incorporated by reference to Exhibit 10.2 of Registrant s Current Report on Form 8-K filed November 4, 2004, File No. 1-3876).
10.10*	Form of Executive Restricted Stock Agreement [two-year term and performance vesting form] (incorporated by reference to Exhibit 10.3 of Registrant s Current Report on Form 8-K filed November 4, 2004, File No. 1-3876).
10.11*	Form of Executive Restricted Stock Agreement [five-year term vesting form] (incorporated by reference to Exhibit 10.4 of Registrant s Current Report on Form 8-K filed November 4, 2004, File No. 1-3876).
10.12*	Form of Executive Restricted Stock Agreement [five-year term and performance vesting form] (incorporated by reference to Exhibit 10.5 of Registrant s Current Report on Form 8-K filed November 4, 2004, File No. 1-3876).
10.13*	Form of Performance Share Unit Agreement (incorporated by reference to Exhibit 10.1 of Registrant s Current Report on Form 8-K filed January 12, 2007, File No. 1-3876).
10.14	Asset Purchase and Sale Agreement between Phillips Petroleum Company as seller and Holly Corporation as buyer dated December 20, 2002 (incorporated by reference to Exhibit 10.1 of Registrant s Quarterly Report on Form 10-Q for the quarterly period ended January 31, 2003, File No. 1-3876).
10.15	Contribution Agreement, dated January 25, 2005, among Holly Energy Partners, L.P., Holly Energy Partners Operating, L.P., T&R Assets, Inc., Alon USA Refining, Inc., Alon Pipeline Assets, LLC, Alon Pipeline Logistics, LLC, Alon USA, Inc. and Alon USA, LP (incorporated by reference to Exhibit 2.1 of Holly Energy Partners, L.P. s Current Report on Form 8-K filed January 31, 2005, File No. 1-32225).

10.16	Purchase and Sale Agreement, dated July 6, 2005 by and among Holly Corporation, Navajo Pipeline Co., L.P., Navajo Refining Company, L.P., Holly Energy Partners, L.P., Holly Energy Partners Operating, L.P. and HEP Pipeline, L.L.C. (incorporated by reference to Exhibit 2.1 of Holly Energy Partners, L.P. s Current Report on Form 8-K filed July 12, 2005, File No. 1-32225).

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Exhibit Number	Description
10.17	Credit Agreement, dated July 1, 2004, among Holly Corporation, as borrower, Bank of America, N.A. as administrative agent and L/C Issuer, Guaranty Bank and PNC Bank, National Association as co-documentation agents, Union Bank of California, N.A. as syndication agent, The Other lenders Party hereto, and Banc of America Securities LLC, as lead arranger and sole book manager (incorporated by reference to Exhibit 10.1 of Registrant s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004, File No. 1-3876).
10.18	The First Amendment and Waiver dated January 25, 2005 and entered into by and between Holly Corporation, each of the lenders, and Bank of America, N.A., in its capacity as the administrative agent for the lenders under the Credit Agreement (incorporated by reference to Exhibit 99.1 of Registrant s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2005, File No. 1-3876).
10.19	The Second Amendment dated May 17, 2005 and entered into by and between Holly Corporation, each of the lenders, and Bank of America, N.A., in its capacity as the administrative agent for the lenders under the Credit Agreement (incorporated by reference to Exhibit 99.2 of Registrant s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2005, File No. 1-3876).
10.20	The Third Amendment dated December 23, 2005 and entered into by and between Holly Corporation, each of the lenders, and Bank of America, N.A., in its capacity as the administrative agent for the lenders under the Credit Agreement (incorporated by reference to Exhibit 10.23 of Registrant s Annual Report on form 10-K for its fiscal year ended December 31, 2005, File No. 1-3876).
10.21	Guarantee and Collateral Agreement, dated July 1, 2004, among Holly Corporation and certain of its Subsidiaries in favor of Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.2 of Registrant s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004, File No. 1-3876).
10.22	Credit Agreement, dated July 7, 2004, among HEP Operating Company, L.P., as borrower, the financial institutions party to this agreement, as banks, Union Bank of California, N.A., as administrative agent and sole lead arranger, Bank of America, National Association, as syndication agent, and Guaranty Bank, as documentation agent (incorporated by reference to Exhibit 10.1 of Holly Energy Partners, L.P. s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2004, File No. 1-32225).
10.23	Consent and Agreement, dated July 13, 2004 among Holly Energy Partners, L.P., Union Bank of California, N.A., as administrative agent, and certain other lending institutions identified therein (incorporated by reference to Exhibit 10.3 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2004, File No. 1-32225).
10.24	Consent, Waiver and Amendment No. 2, dated February 28, 2005, among HEP Operating Company, L.P., the existing guarantors identified therein, Union Bank of California, N.A., as administrative agent, and certain other lending institutions identified therein (incorporated by reference to Exhibit 10.3 of Holly Energy Partners, L.P. s Current Report on Form 8-K filed March 4, 2005, File No. 1-32225).
10.25	Waiver and Amendment No. 3, dated June 17, 2005, among Holly Energy Partners, L.P., Union Bank of California, N.A., as administrative agent, and certain other lending institutions identified therein

(incorporated by reference to Exhibit 10.3 of Holly Energy Partners, L.P. s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2005 , File No. 1-32225).

Exhibit Number	Description
10.26	Consent and Amendment No. 4, dated July 8, 2005, among Holly Energy Partners, L.P., Union Bank of California, N.A., as administrative agent, and certain other lending institutions identified therein (incorporated by reference to Exhibit 10.3 of Holly Energy Partners, L.P. s Current Report on Form 8-K filed July 12, 2005, File No. 1-32225).
10.27*	Form of Indemnification Agreement entered into with directors and officers of Holly Corporation (incorporated by reference to Exhibit 10.1 of Registrant s Current Report on Form 8-K filed December 13, 2006, File No. 1-3876).
21.1+	Subsidiaries of Registrant.
23.1+	Consent of Independent Registered Public Accounting Firm.
31.1+	Certification of Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002.
31.2+	Certification of Chief Financial Officer under Section 302 of the Sarbanes-Oxley Act of 2002.
32.1+	Certification of Chief Executive Officer under Section 906 of the Sarbanes-Oxley Act of 2002.
32.2+	Certification of Chief Financial Officer under Section 906 of the Sarbanes-Oxley Act of 2002.

+ Filed herewith.

* Constitutes management contracts or compensatory plans or arrangements.