HOLLY CORP
Form 10-Q
November 06, 2006

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 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 principal executive offices)	(Zip Code)

(214) 871-3555

(Registrant s telephone number, including area code)

(Former name, former address and former fiscal year, if changed since last report)

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 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

56,144,479 shares of Common Stock, par value $.01 per share, were outstanding on October 31, 2006.

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PART I FINANCIAL INFORMATION

FORWARD-LOOKING STATEMENTS

References throughout this document to Holly Corporation include Holly Corporation and its consolidated subsidiaries. In accordance with the Securities and Exchange Commission s (SEC) Plain English guidelines, this Quarterly Report on Form 10-Q 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.

This Quarterly Report on Form 10-Q 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-Q, including, but not limited to, those under Results of Operations, Liquidity and Capital Resources and Additional Factors that May Affect Future Results (including Risk Management) in Item 2 Management s Discussion and Analysis of Financial Condition and Results of Operations in Part I and those in Item 1 Legal Proceedings in Part II, are forward-looking statements. These statements are based on management s beliefs 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 or pipeline or terminal 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-Q, including without limitation in conjunction with the forward-looking statements included in this Form 10-Q that are referred to above. This summary discussion should be read in conjunction with the discussion of risk factors and other cautionary statements under the heading Risk Factors included in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2005 and in conjunction with the discussion in this Form 10-Q in Management s Discussion and Analysis of Financial Condition and Results of Operations under the headings Liquidity and Capital Resources. All forward-looking statements included in this Form 10-Q 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 the breaking down of large, complex hydrocarbon molecules into smaller, more useful ones by the application of heat, pressure and a chemical (catalyst) to speed the process.

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

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 converting C5/C6 gasoline compounds into their isomers, i.e., rearranging the structure of the molecules without changing their size or chemical composition.

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.

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.

PPM means parts-per-million.

Refining gross margin or refinery gross margin means the difference between average net sales price and average costs of products per barrel of produced refined products. This margin does not include the effect of 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.

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Solvent deasphalter / residuum oil supercritical extraction (ROSE) means a refinery process 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 equal to or greater than 0.4 percent by weight, while sweet crude oil means crude oil containing quantities of sulfur 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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Item 1. Financial Statements

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

	September 30, 2006 (Unaudited)	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 194,628	$ 49,064
Marketable securities	91,755	189,978
Accounts receivable: Product and transportation	175,042	145,736
Crude oil resales	222,209	254,734
Related party receivable	2,519	1,434
	399,770	401,904
Inventories: Crude oil and refined products	90,584	91,257
Materials and supplies	13,713	12,082
	104,297	103,339
Income taxes receivable	725	
Prepayments and other	28,715	14,639
Assets of discontinued operations	624	30,612
Total current assets	820,514	789,536
Properties, plants and equipment, at cost	611,902	532,641
Less accumulated depreciation, depletion and amortization	(229,010)	(216,502)
	382,892	316,139
Marketable securities (long-term)	4,074	15,800
Other assets: Turnaround costs (long-term)	6,351	7,309
Intangibles and other	14,961	14,116
	21,312	21,425
Total assets	$ 1,228,792	$ 1,142,900
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		

Accounts payable	$ 516,810	$ 518,584
Accrued liabilities	45,506	41,235
Income taxes payable		5,538
Liabilities of discontinued operations	4,237	14,076
Total current liabilities	566,553	579,433
Deferred income taxes	22,122	9,989
Other long-term liabilities	13,678	19,101
Commitments and contingencies		
Distributions in excess of investment in Holly Energy Partners	163,701	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; 71,747,560 and 35,378,646 shares issued as of September 30, 2006 and December 31, 2005, respectively	717	354
Additional capital	63,180	43,344
Retained earnings	702,760	495,819
Accumulated other comprehensive loss	(5,183)	(4,802)
Common stock held in treasury, at cost 15,793,926 and 6,002,175 shares as of September 30, 2006 and December 31, 2005, respectively	(298,736)	(157,364)
Total stockholders equity	462,738	377,351
Total liabilities and stockholders equity	$ 1,228,792	$ 1,142,900

See accompanying notes.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
Sales and other revenues	$ 1,172,693	$ 880,520	$ 3,085,127	$ 2,233,895
Operating costs and expenses:				
Cost of products sold (exclusive of depreciation, depletion and amortization)	979,309	725,286	2,562,803	1,828,632
Operating expenses (exclusive of depreciation, depletion and amortization)	54,146	42,287	155,705	132,031
General and administrative expenses (exclusive of depreciation, depletion and amortization)	12,566	12,619	44,813	35,527
Depreciation, depletion and amortization	9,480	8,549	28,187	31,896
Exploration expenses, including dry holes	102	69	329	310
Total operating costs and expenses	1,055,603	788,810	2,791,837	2,028,396
Income from operations	117,090	91,710	293,290	205,499
Other income (expense):				
Equity in loss of joint ventures				(685)
Equity in earnings of Holly Energy Partners	3,596	3,296	8,324	3,296
Minority interests in income of partnerships				(6,721)
Interest income	2,747	1,202	6,890	4,455
Interest expense	(268)	(501)	(815)	(4,706)
	6,075	3,997	14,399	(4,361)
Income from continuing operations before income taxes	123,165	95,707	307,689	201,138
Income tax provision:				
Current	37,918	36,360	101,762	75,385
Deferred	6,046	(670)	7,837	217
	43,964	35,690	109,599	75,602
Income from continuing operations before cumulative change in accounting principle	79,201	60,017	198,090	125,536
Cumulative effect of accounting change (net of income tax expense of $426)		669		669
Income from continuing operations	79,201	60,686	198,090	126,205

Discontinued operations				
Income from discontinued operations	21	1,033	7,012	1,572
Gain (loss) on sale of discontinued operations	(220)		13,805	
Income (loss) from discontinued operations, net of taxes	(199)	1,033	20,817	1,572
Net income	$ 79,002	$ 61,719	$ 218,907	$ 127,777
Basic earnings per share:				
Continuing operations	$ 1.40	$ 0.99	$ 3.45	$ 2.02
Discontinued operations		0.02	0.36	0.02
Net income	$ 1.40	$ 1.01	$ 3.81	$ 2.04
Diluted earnings per share:				
Continuing operations	$ 1.37	$ 0.97	$ 3.38	$ 1.97
Discontinued operations		0.01	0.35	0.03
Net income	$ 1.37	$ 0.98	$ 3.73	$ 2.00
Cash dividends declared per common share	$ 0.08	$ 0.05	$ 0.21	$ 0.14
Average number of common shares outstanding:				
Basic	56,555	61,236	57,393	62,506
Diluted	57,783	62,772	58,643	63,960

See accompanying notes.

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HOLLY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(In thousands)

	Nine Months Ended September 30,	
	2006	**2005**
Cash flows from operating activities:		
Net income	$ 218,907	$ 127,777
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization (includes discontinued operations)	28,737	34,336
Deferred income taxes (includes discontinued operations)	5,395	131
Minority interests in income of partnerships		6,721
Distributions in excess of equity in earnings of HEP and joint ventures	6,675	1,706
Equity based compensation expense	3,883	1,608
Gain on sale of assets, before income taxes	(22,004)	
(Increase) decrease in current assets:		
Accounts receivable	13,531	(199,045)
Inventories	(8,414)	(1,336)
Income taxes receivable	(725)	10,735
Prepayments and other	(10,744)	(10)
Increase (decrease) in current liabilities:		
Accounts payable	(17,295)	166,589
Accrued liabilities	9,431	(1,026)
Income taxes payable	(5,354)	18,964
Turnaround expenditures	(7,122)	(1,038)
Other, net	(6,630)	(3,236)
Net cash provided by operating activities	208,271	162,876
Cash flows from investing activities:		
Additions to properties, plants and equipment	(89,182)	(58,062)
Net cash proceeds from sale of Montana Refinery	48,872	
Acquisition by HEP of pipeline and terminal assets		(121,853)
Decrease in cash due to deconsolidation of HEP		(20,447)
Purchase of additional interest in joint venture, net of cash		(18,506)
Proceeds from sale of partial interest in joint venture		832
Purchases of marketable securities	(172,291)	(254,801)
Sales and maturities of marketable securities	285,943	209,371
Net cash provided by (used for) investing activities	73,342	(263,466)
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
Net decrease in borrowings under revolving credit agreements		(25,000)
Debt issuance costs		(948)
Issuance of common stock upon exercise of options	2,424	2,736
Purchase of treasury stock	(138,369)	(80,899)

Cash dividends	(10,475)	(8,232)
Cash distributions to minority interests		(9,486)
Excess tax benefit from equity based compensation	10,371	5,525
Net cash provided by (used for) financing activities	(136,049)	109,439
Cash and cash equivalents:		
Increase for the period	145,564	8,849
Beginning of period	49,064	67,460
End of period	$ 194,628	$ 76,309
Supplemental disclosure of cash flow information:		
Cash paid during the period for		
Interest	$ 510	$ 1,486
Income taxes	$ 112,274	$ 40,569

See accompanying notes.

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HOLLY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)
(In thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
Net income	$ 79,002	$ 61,719	$ 218,907	$ 127,777
Other comprehensive income (loss):				
Securities available for sale:				
Unrealized gain (loss) on available for sale securities	(332)	131	(531)	106
Reclassification adjustment to net income on sale of equity securities	(84)		(94)	
Total unrealized gain (loss) on available for sale securities	(416)	131	(625)	106
Income tax expense (benefit)	(163)	51	(244)	41
Other comprehensive income (loss)	(253)	80	(381)	65
Total comprehensive income	$ 78,749	$ 61,799	$ 218,526	$ 127,842

See accompanying notes.

HOLLY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

NOTE 1: Description of Business and Presentation of Financial Statements

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 Quarterly report on Form 10-Q has been written in the first person. In this document, the words we , our , ours and us refer only to Holly Corporatio and its consolidated subsidiaries or to Holly Corporation or an individual subsidiary and not to any other person.

As of the close of business on September 30, 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;

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

owned a 45.0% interest in Holly Energy Partners, L.P. (HEP), which owns logistic assets including approximately 1,600 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 Pipeline Company (Rio Grande).

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 gain of $13.8 million on the sale are shown in discontinued operations (see Note 2).

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. Under the provision of the Financial Accounting Standards Board (FASB) Interpretation No. 46 (revised) (FIN 46) Consolidation of Variable Interest Entities, we have deconsolidated HEP effective July 1, 2005. The deconsolidation is being presented from July 1, 2005 forward (see Note 3).

We have prepared these consolidated financial statements without audit. In management s opinion, these consolidated financial statements include all normal recurring adjustments necessary for a fair presentation of our consolidated financial position as of September 30, 2006, the consolidated results of operations and comprehensive income for the three months and nine months ended September 30, 2006 and 2005 and consolidated cash flows for the nine months ended September 30, 2006 and 2005 in accordance with the rules and regulations of the SEC. Although certain notes and other information required by accounting principles generally accepted in the United States have been condensed or omitted, we believe that the disclosures in these consolidated financial statements are adequate to make the information presented not misleading. These consolidated financial statements should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2005 filed with the SEC.

We use the last-in, first-out (LIFO) method of valuing inventory. 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.

Our results of operations for the first nine months of 2006 are not necessarily indicative of the results to be expected for the full year. Certain reclassifications, which we determined to be immaterial, have been made to prior reported amounts to conform to current classifications. Due to the sale of the Montana Refinery, we reclassified certain amounts previously reported and now report such amounts as from discontinued operations.

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Our operations are currently organized into one business division, Refining. The Refining business division includes the Navajo Refinery, Woods Cross Refinery and NK Asphalt Partners. We previously included the Montana Refinery in the Refining division, and the results from the Montana Refinery are now reported in discontinued operations. 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.

New Accounting Pronouncements

SFAS No. 151 Inventory Costs, an amendment of ARB No. 43, Chapter 4

In December 2004, the FASB issued SFAS No. 151, Inventory Costs, an Amendment of ARB No. 43, Chapter 4. This amendment requires abnormal amounts of idle facility expense, freight, handling costs and wasted materials (spoilage) to be recognized as current-period charges. This standard also requires that the allocation of fixed production overhead to the cost of conversion be based on the normal capacity of the production facilities. This standard is effective for fiscal years beginning after June 15, 2005. We adopted the standard effective January 1, 2006. The adoption of this standard did not have a material effect on our financial condition, results of operations or cash flows.

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.

With respect to supplying crude oil to our refineries, crude oil is often purchased in locations distant from our refineries and exchanged for crude oil that is transportable to our refineries. These buy/sell exchanges are done in contemplation of one another and allow us to receive the optimal crude blend and quantities at our refineries. All of the crude oil buy/sell transactions done in supplying crude oil to our refineries are recorded as exchanges with the net differential reflected in costs of sales. We also purchase crude oil from producers and other petroleum companies in excess of the needs of our refineries for resale to other purchasers or users of crude oil. With respect to these resales that are in the form of buy/sell exchanges with the same counterparty, the net differential of the exchanges is reflected in cost of products sold. Additionally, certain direct sales of this excess crude oil are made to purchasers or users of crude oil. Under the new accounting guidance, these direct 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 in cost of products sold. Prior to our adoption of EITF 04-13, sales and cost of sales attributable to such excess crude oil direct sales were netted and presented in cost of products sold. During the quarter and nine months ended September 30, 2006, these crude oil sales amounted to $143.1 million and $274.4 million with corresponding costs of $142.9 million and $273.9 million, respectively, resulting in gains on these transactions of $0.2 million and $0.5 million, respectively.

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

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transition. This interpretation is effective for fiscal years beginning after December 15, 2006. We are currently evaluating the impact the adoption of this interpretation will have 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 believe the adoption of this standard will not 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 are currently evaluating the impact the adoption of this standard will have on our financial condition, results of operations and cash flows.

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 approximately $4.3 million at March 31, 2006. In accounting for the sale, we recorded a pre-tax gain of $22.4 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 $2.0 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
	(In thousands)			
Sales and other revenues from discontinued operations	$ 51	$ 54,759	$ 53,912	$ 124,405
Income from discontinued operations before income taxes	$ 31	$ 1,660	$ 11,176	$ 2,526
Income tax expense	(10)	(627)	(4,164)	(954)
Income from discontinued operations, net	21	1,033	7,012	1,572
Gain (loss) on sale of discontinued operations before income taxes	(354)		22,004	
Income tax (expense) benefit	134		(8,199)	
Gain (loss) on sale of discontinued operations, net	(220)		13,805	

Income (loss) from discontinued operations, net	$ (199)	$ 1,033	$ 20,817	$ 1,572

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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 45.0% 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 a volume of refined products that will result in a minimum level of revenue to HEP of $36.7 million annually. Under the HEP IPA, we agreed to transport volumes of intermediate products on the intermediate pipelines that will result in a minimum level of revenues to HEP of approximately $11.8 million annually. Minimum revenues 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 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 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 million principal amount of 6.25% senior notes due 2015 (HEP Senior Notes). HEP used the proceeds of the offering to fund the $120 million cash portion of the consideration for the Alon transaction, and used the balance to repay $30 million of outstanding indebtedness under HEP s credit agreement, including $5 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 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 approximately $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 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

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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.

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 controlling partner to the extent it makes any payment in satisfaction of $35 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 September 30, 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 nine months ended September 30, 2006 (In thousands):

Investment in HEP balance at December 31, 2005	$ (157,026)
Equity in the earnings of HEP	8,324
Regular quarterly distributions from HEP	(14,999)
Investment in HEP balance at September 30, 2006	$ (163,701)

The following tables provide summary financial results for HEP.

	September 30, 2006	December 31, 2005
	(In thousands)	
Current assets	$ 20,997	$ 28,705
Properties and equipment, net	160,894	162,298
Transportation agreements and other	60,610	63,772
Total assets	$ 242,501	$ 254,775
Current liabilities	$ 12,456	$ 9,251
Long-term liabilities	181,801	181,711
Minority interest	10,638	11,753
Partners equity	37,606	52,060
Total liabilities and partners equity	$ 242,501	$ 254,775

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
	(In thousands)			
Revenues	$ 22,899	$ 21,517	$ 63,864	$ 57,551
Operating costs and expenses	12,098	11,332	36,723	31,347
Operating income	10,801	10,185	27,141	26,204
Other expenses, net	(3,050)	(2,893)	(9,257)	(6,545)
Net income	$ 7,751	$ 7,292	$ 17,884	$ 19,659

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

Pipeline and terminal expenses paid to HEP were $14.3 million and $12.5 million for the three months ended September 30, 2006 and 2005, respectively, and $37.3 million and $31.9 million for the nine months ended September 30, 2006 and 2005, respectively.

We charged HEP $0.5 million for the three months ended September 30, 2006 and 2005 and $1.5 million for the nine months ended September 30, 2006 and 2005 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 $2.0 million and $1.8 million for the three months ended September 30, 2006 and 2005, respectively, and $5.7 million and $4.8 million for the nine months ended September 30, 2006 and 2005, respectively, which we recorded as a reduction in expenses.

We reimbursed HEP $42,000 and $47,000 for certain costs paid on our behalf for the three months ended September 30, 2006 and 2005, respectively, and $138,000 and $161,000 for the nine months ended September 30, 2006 and 2005, respectively.

We received as regular distributions on our subordinated units, common units and general partner interest, $5.2 million and $4.3 million for the three months ended September 30, 2006 and 2005, respectively, and $15.0 million and $12.0 million for the nine months ended September 30, 2006 and 2005, respectively. Our distributions for the three months ended September 30, 2006 and 2005 included $0.3 million and $0.1, respectively, in incentive distributions with respect to our general partner interest. General partner incentive distributions of $0.8 million and $0.1 were included in our distributions for the nine months ended September 30, 2006 and 2005, respectively.

We had a net payable to HEP of $2.3 million and $3.6 million at September 30, 2006 and December 31, 2005, respectively.

Prepayments and other includes $2.7 million and $1.0 million at September 30, 2006 and December 31, 2005, respectively, related to minimum revenue payments under the HEP IPA which may be applied as credits against future billings from HEP when our shipments exceed the minimum volume commitments on the intermediate pipelines.

NOTE 4: Earnings Per Share

Basic income per share is calculated as net income divided by average number of shares of common stock outstanding. Diluted income per share assumes, when dilutive, issuance of the net incremental shares from stock options and variable performance shares. 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. The following is a reconciliation of the numerators and denominators of the basic and diluted per share computations of income:

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In thousands, except per share data)			
Net income	$ 79,002	$ 61,719	$ 218,907	$ 127,777
Average number of shares of common stock outstanding	56,555	61,236	57,393	62,506
Effect of dilutive stock options and variable restricted shares	1,228	1,536	1,250	1,454
Average number of shares of common stock outstanding assuming dilution	57,783	62,772	58,643	63,960
Income per share basic	$ 1.40	$ 1.01	$ 3.81	$ 2.04
Income per share diluted	$ 1.37	$ 0.98	$ 3.73	$ 2.00

NOTE 5: Stock-Based Compensation

On September 30, 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 $14.0 million and $5.6 million for the nine months ended September 30, 2006 and 2005, respectively. The total income tax benefit recognized in the income statements for share-based compensation arrangements was $5.4 million and $2.2 million for the nine months ended September 30, 2006 and 2005, 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 September 30, 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 split effective June 1, 2006.

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 on the date of grant of each option awarded has been estimated using the Black-Scholes option pricing model.

A summary of option activity as of September 30, 2006, and changes during the nine months ended September 30, 2006 is presented below:

	Weighted Average	Weighted-Average Remaining	Aggregate Intrinsic

Options	Shares	Exercise Price	Contractual Term	Value ($000)
Outstanding at January 1, 2006	2,479,500	$ 2.50		
Exercised	(824,300)	$ 2.94		
Forfeited or expired				
Outstanding at September 30, 2006	1,655,200	$ 2.28	3.5	$ 67,950
Exercisable at September 30, 2006	1,615,200	$ 2.21	3.5	$ 66,415

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The total intrinsic value of options exercised during the nine months ended September 30, 2006 and 2005, was $27.1 million and $14.7 million, respectively.

A summary of the status of our nonvested options as of September 30, 2006 and changes during the nine months ended September 30, 2006, is presented below:

Nonvested Options	Options	Weighted-Average Grant-Date Fair Value
Nonvested at January 1, 2006	408,800	$ 1.02
Vested	(368,800)	$ 0.91
Forfeited		
Nonvested at September 30, 2006	40,000	$ 1.99

As of September 30, 2006, there was $18,000 of total unrecognized compensation cost related to the stock options granted. That cost is expected to be recognized over a weighted-average period of two months. The total fair value of shares vested during the nine months ended September 30, 2006 and 2005, was $0.3 million and $0.4 million, respectively.

Cash received from option exercises under the stock option plans for the nine months ended September 30, 2006 and 2005, was $2.4 million and $2.7 million, respectively. The actual tax benefit realized for the tax deductions from option exercises under the stock option plans totaled $10.4 million and $5.5 million for the nine months ended September 30, 2006 and 2005, 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 vesting periods, as we assume all restricted shares will fully vest.

A summary of restricted stock grant activity as of September 30, 2006, and changes during the nine months ended September 30, 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 September 30, 2006 (not vested)	494,922	$ 15.07	$ 23,855

The total intrinsic value of restricted stock vested and transferred to recipients during the nine months ended September 30, 2006 and 2005 was $5.5 million and $2.5 million, respectively. As of September 30, 2006, there was $3.6 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 1.5 years. The total fair value of shares vested during the nine months ended September 30, 2006 was $1.0 million.

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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 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 (as 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 nine months ended September 30, 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 the nine months, September 30, 2006.

At February 10, 2006, the price of our stock was $31.96 (as adjusted for the two-for-one stock split effective June 1, 2006), the latest quarterly dividend was $0.05 (as 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 September 30, 2006, the price of our stock was $43.33, the latest quarterly dividend was $0.08, and the risk-free rates ranged from 4.38% to 4.86%, 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

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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%	13.1% to 13.6%
Peer group	10.3% to 13.5%	10.1% to 16.0%

A summary of performance share units activity as of September 30, 2006, and changes during the nine months ended September 30, 2006 is presented below:

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	(4,456)			(4,456)
Outstanding at September 30, 2006 (nonvested)	223,494	128,574	75,984	428,052

There was no cash paid during the nine months ended September 30, 2006 related to vested performance share units, while $6.3 million was paid during the nine months ended September 30, 2005 related to vested performance share units. As of September 30, 2006, the cash liability associated with these awards was $13.8 million and is recorded in accrued liabilities on our consolidated balance sheets. Based on the weighted average fair value at September 30, 2006 of $57.21, there was $6.2 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 0.9 years.

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. Unrealized gains and losses, net of related income taxes, are temporary and reported as a component of accumulated other comprehensive income.

The following is a summary of our available-for-sale securities at September 30, 2006:

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	Available-for-Sale Securities		
	Amortized Cost	Gross Unrealized Losses	Estimated Fair Value (Net Carrying Amount)
		(In thousands)	
States and political subdivisions	$ 92,619	$ (20)	$ 92,599
Equity securities	4,328	(1,098)	3,230
Total marketable securities	$ 96,947	$ (1,118)	$ 95,829

During the nine months ended September 30, 2006 and 2005, we recognized $94,000 in gains related to 232 sales and maturities and $0.3 million in losses related to 168 sales and maturities respectively, in which we received $285.9 million and $209.4 million in proceeds, respectively. The realized gains and losses represent the difference between the purchase price and market value on the maturity or sales dates.

NOTE 7: Investments in Joint Ventures

Prior to February 2005, NK Asphalt Partners was owned 49% by us and 51% by a subsidiary of Koch Materials Company (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.

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 8: Environmental

Consistent with our accounting policy for environmental remediation and cleanup costs, we expensed $3.6 million during the nine months ended September 30, 2006 and $0.4 million during the nine months ended September 30, 2005 for environmental remediation and cleanup obligations and certain environmental obligations retained in connection with our sale of the Montana Refinery. The accrued environmental liability reflected in the consolidated balance sheets was $6.2 million and $3.1 million at September 30, 2006 and December 31, 2005, respectively, of which $4.5 million and $2.0 million was classified as other long-term liabilities, respectively. Costs of future expenditures for environmental obligations are not discounted to their present value.

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NOTE 9: Debt

Credit Facility

We have a $175 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 million subject to certain conditions. This credit facility expires in 2008 and may be used to fund working capital requirements, capital expenditures, acquisitions or other general corporate purposes. We were in compliance with all covenants at September 30, 2006. At September 30, 2006, we had 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 credit facility was $172.7 million at September 30, 2006.

NOTE 10: Income taxes

The effective tax rate for continuing operations for the first nine months of 2006 was 35.6%, as compared to 37.6% for the first nine months of 2005. The reduction in the effective tax rate was principally due to income tax credits available to small business refiners incurring costs to produce ultra low sulfur diesel fuel.

NOTE 11: Stockholders Equity

Two-For-One Stock Split: 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. 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 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. 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 nine months ended September 30, 2006, we repurchased under this repurchase initiative 3,743,188 shares at a cost of approximately $140.0 million (of which $3.0 million of the cash settlement was after September 30, 2006) or an average of $37.40 per share. Since inception of this repurchase initiative through September 30, 2006, we have repurchased 4,730,788 shares at a cost of approximately $169.9 million or an average of $35.92 per share.

On October 30, 2006, we announced that our Board of Directors had authorized a $100 million increase in the $200 million common stock repurchase program. The increase raises the authorized repurchase limit under the common stock repurchase program from $200 million to $300 million.

In October 2005, we completed the purchase of $100 million of our common stock, pursuant to a repurchase program authorized by our Board of Directors which we had announced in May 2005. 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. During 2005, we repurchased 4,062,414 shares at a cost of approximately $100.0 million or an average of $24.62 per share under this repurchase initiative.

We have also made repurchases 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. During the nine months ended September 30, 2006, we repurchased at current market price from certain executives 46,388 shares of our common stock at a cost of approximately $1.4 million. During the nine months ended September 30, 2005, we repurchased at current market price from certain executives 49,580 shares of our common stock at a cost of approximately $0.8 million.

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NOTE 12: Other Comprehensive Income

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

	Before-Tax	Tax Expense (Benefit)	After-Tax
		(In thousands)	
For the three months ended September 30, 2006			
Unrealized loss on securities available for sale	$ (416)	$ (163)	$ (253)
Other comprehensive loss	$ (416)	$ (163)	$ (253)
For the three months ended September 30, 2005			
Unrealized gain on securities available for sale	$ 131	$ 51	$ 80
Other comprehensive income	$ 131	$ 51	$ 80
For the nine months ended September 30, 2006			
Unrealized loss on securities available for sale	$ (625)	$ (244)	$ (381)
Other comprehensive loss	$ (625)	$ (244)	$ (381)
For the nine months ended September 30, 2005			
Unrealized gain on securities available for sale	$ 106	$ 41	$ 65
Other comprehensive income	$ 106	$ 41	$ 65

The temporary unrealized loss or gain on securities available for sale is due to changes in market prices of securities.
Accumulated other comprehensive loss in the equity section of our consolidated balance sheets includes:

	September 30, 2006	December 31, 2005
	(In thousands)	
Pension obligation adjustment	$ (4,501)	$ (4,501)
Unrealized loss on securities available for sale	(682)	(301)
Accumulated other comprehensive loss	$ (5,183)	$ (4,802)

NOTE 13: 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 under the Employee Retirement Income Security Act of 1974. Benefits are based on the employees years of service and compensation.

The net periodic pension expense consisted of the following components:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In thousands)			
Service cost	$ 1,022	$ 862	$ 3,248	$ 2,585
Interest costs	1,018	941	3,115	2,824
Expected return on assets	(863)	(791)	(2,611)	(2,372)
Amortization of prior service cost	63	66	196	196
Amortization of net loss	217	241	825	724
One time cost incurred with sale of Montana Refinery			300	
Net periodic benefit cost	$ 1,457	$ 1,319	$ 5,073	$ 3,957

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The expected long-term annual rate of return on plan assets is 8.5%. This rate was used in measuring 2006 and 2005 net periodic benefit cost. We contributed $13.0 million to the retirement plan in the third quarter of 2006.

NOTE 14: Contingencies

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 Kinder Morgan s SFPP, L.P. (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 Environmental Protection Agency (EPA) and the State of Utah have asserted that we have liabilities relating to the Federal Clean Air Act at 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.

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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 late October 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 methyl tertiary butyl ether (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.

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 15: Segment Information

Our operations are currently organized into one business division, Refining. The Refining business division includes the Navajo Refinery, Woods Cross Refinery and NK Asphalt Partners. Our operations that are not included in the Refining business division 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 division, the 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 business divisions, 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 business divisions 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 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

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provided for our refining operations and from HEP s interest in Rio Grande. Our operations not included in the reportable segment or segments were included in Corporate and Other, which included 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. 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 are the same as those described in the summary of significant accounting policies in our Annual Report on Form 10-K for the year ended December 31, 2005. 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)		
Three Months Ended September 30, 2006					
Sales and other revenues	$1,172,409	$	$ 404	$ (120)	$1,172,693
Depreciation, depletion and amortization	$ 9,079	$	$ 401	$	$ 9,480
Income (loss) from operations	$ 129,775	$	$(12,685)	$	$ 117,090
Income (loss) from continuing operations before income taxes	$ 133,439	$	$(10,274)	$	$ 123,165
Three Months Ended September 30, 2005					
Sales and other revenues	$ 880,228	$	$ 417	$ (125)	$ 880,520
Depreciation, depletion and amortization	$ 8,255	$	$ 294	$	$ 8,549
Income (loss) from operations	$ 104,262	$	$(12,552)	$	$ 91,710
Income (loss) from continuing operations before income taxes	$ 107,562	$	$(11,855)	$	$ 95,707
Nine Months Ended September 30, 2006					
Sales and other revenues	$3,084,595	$	$ 928	$ (396)	$3,085,127
Depreciation, depletion and amortization	$ 27,046	$	$ 1,141	$	$ 28,187
Income (loss) from operations	$ 338,670	$	$(45,380)	$	$ 293,290
Income (loss) from continuing operations before income taxes	$ 347,295	$	$(39,606)	$	$ 307,689
Nine Months Ended September 30, 2005					
Sales and other revenues	$2,216,526	$36,034	$ 1,034	$(19,699)	$2,233,895
Depreciation, depletion and amortization	$ 24,778	$ 6,212	$ 906	$	$ 31,896
Income (loss) from operations	$ 223,182	$16,019	$(33,702)	$	$ 205,499
	$ 225,829	$12,367	$(30,739)	$ (6,319)	$ 201,138

Income (loss) from continuing operations before income taxes

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Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

This Item 2 contains forward-looking statements. See Forward-Looking Statements at the beginning of Part I of this quarterly report of Form 10-Q. In this document, the words we , our 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 September 30, 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 Account 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 nine months ended September 30, 2006, we recorded crude oil sales under this new guidance of $274.4 million with a corresponding cost of $273.9 million, resulting in a gain on these transactions of $0.5 million. Our total sales and other revenues for the nine months ended September 30, 2006 were $3,085.1 million and our net income for the nine months ended September 30, 2006 was $218.9 million. Our sales and other revenues and net income for the nine months ended September 30, 2005 were $2,233.9 million and $127.8 million, respectively. Our principal expenses are costs of products sold and operating expenses. Our total operating costs and expenses for the nine months ended September 30, 2006 were $2,791.8 million, an increase from $2,028.4 million for the nine months ended September 30, 2005.

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 have been adjusted to reflect the split on a retrospective basis.

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. We have presented in discontinued operations the results of the Montana Refinery operations and a gain of $13.8 million on the sale.

On November 7, 2005, we announced that our Board of Directors had authorized the repurchase of up to $200.0 million of our common stock. 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 nine months ended September 30, 2006, we repurchased under this repurchase initiative 3,743,188 shares at a cost of approximately $140.0 million (of which $3.0 million of the cash settlement was after September 30, 2006) or an average of $37.40 per share. Since inception of this repurchase initiative through September 30, 2006, we have repurchased 4,730,788 shares at a cost of approximately $169.9 million or an average of $35.92 per share.

On October 30, 2006, we announced that our Board of Directors had authorized a $100 million increase in the $200 million common stock repurchase program. The increase raises the authorized repurchase limit under the common stock repurchase program from $200 million to $300 million.

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RESULTS OF OPERATIONS
Financial Data (Unaudited)

	Three Months Ended September 30, 2006	2005 (1)	Change from 2005 Change	Percent
	(In thousands, except per share data)			
Sales and other revenues	$ 1,172,693	$ 880,520	$ 292,173	33.2%
Operating costs and expenses:				
Cost of products sold (exclusive of depreciation, depletion and amortization)	979,309	725,286	254,023	35.0
Operating expenses (exclusive of depreciation, depletion and amortization)	54,146	42,287	11,859	28.0
General and administrative expenses (exclusive of depreciation, depletion and amortization)	12,566	12,619	(53)	(0.4)
Depreciation, depletion and amortization	9,480	8,549	931	10.9
Exploration expenses, including dry holes	102	69	33	47.8
Total operating costs and expenses	1,055,603	788,810	266,793	33.8
Income from operations	117,090	91,710	25,380	27.7
Other income (expense):				
Equity in earnings of HEP	3,596	3,296	300	9.1
Interest income	2,747	1,202	1,545	128.5
Interest expense	(268)	(501)	233	(46.5)
	6,075	3,997	2,078	52.0
Income from continuing operations before income taxes	123,165	95,707	27,458	28.7
Income tax provision	43,964	35,690	8,274	23.2
Income from continuing operations before cumulative change in accounting principle	79,201	60,017	19,184	32.0
Cumulative effect of accounting change (net of tax expense of $426)		669	(669)	(100.0)
Income from continuing operations	79,201	60,686	18,515	30.5
Income (loss) from discontinued operations, net of taxes	(199)	1,033	(1,232)	(119.3)
Net income	$ 79,002	$ 61,719	$ 17,283	28.0%
Basic earnings per share:				
Continuing operations	$ 1.40	$ 0.99	$ 0.41	41.4%
Discontinued operations		0.02	(0.02)	(100.0)

Net income	$ 1.40	$ 1.01	$ 0.39	38.6%
Diluted earnings per share:				
Continuing operations	$ 1.37	$ 0.97	$ 0.40	41.2%
Discontinued operations		0.01	(0.01)	(100.0)
Net income	$ 1.37	$ 0.98	$ 0.39	39.8%
Cash dividends declared per common share	$ 0.08	$ 0.05	$ 0.03	60.0%
Average number of common shares outstanding:				
Basic	56,555	61,236	(4,681)	(7.6)%
Diluted	57,783	62,772	(4,989)	(7.9)%

(1) Due to the sale of the Montana Refinery, we have reclassified certain amounts previously reported and now report such amounts as from discontinued operations.

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	Nine Months Ended September 30,		Change from 2005	
	2006	2005 (1)	Change	Percent
	(In thousands, except per share data)			
Sales and other revenues	$ 3,085,127	$ 2,233,895	$ 851,232	38.1%
Operating costs and expenses:				
Cost of products sold (exclusive of depreciation, depletion and amortization)	2,562,803	1,828,632	734,171	40.1
Operating expenses (exclusive of depreciation, depletion and amortization)	155,705	132,031	23,674	17.9
General and administrative expenses (exclusive of depreciation, depletion and amortization)	44,813	35,527	9,286	26.1
Depreciation, depletion and amortization	28,187	31,896	(3,709)	(11.6)
Exploration expenses, including dry holes	329	310	19	6.1
Total operating costs and expenses	2,791,837	2,028,396	763,441	37.6
Income from operations	293,290	205,499	87,791	42.7
Other income (expense):				
Equity in loss of joint ventures		(685)	685	(100.0)
Equity in earnings of HEP	8,324	3,296	5,028	152.5
Minority interests in income of partnerships		(6,721)	6,721	(100.0)
Interest income	6,890	4,455	2,435	54.7
Interest expense	(815)	(4,706)	3,891	(82.7)
	14,399	(4,361)	18,760	(430.2)
Income from continuing operations before income taxes	307,689	201,138	106,551	53.0
Income tax provision	109,599	75,602	33,997	45.0
Income from continuing operations before cumulative change in accounting principle	198,090	125,536	72,554	57.8
Cumulative effect of accounting change (net of tax expense of $426)		669	(669)	(100.0)
Income from continuing operations	198,090	126,205	71,885	57.0
Income from discontinued operations, net of taxes	20,817	1,572	19,245	1,224.2
Net income	$ 218,907	$ 127,777	$ 91,130	71.3%
Basic earnings per share:				
Continuing operations	$ 3.45	$ 2.02	$ 1.43	70.8%
Discontinued operations	0.36	0.02	0.34	1,700.0

Net income	$	3.81	$	2.04	$	1.77	86.8%
Diluted earnings per share:							
Continuing operations	$	3.38	$	1.97	$	1.41	71.6%
Discontinued operations		0.35		0.03		0.32	1,066.7
Net income	$	3.73	$	2.00	$	1.73	86.5%
Cash dividends declared per common share	$	0.21	$	0.14	$	0.07	50.0%
Average number of common shares outstanding:							
Basic		57,393		62,506		(5,113)	(8.2)%
Diluted		58,643		63,960		(5,317)	(8.3)%

(1) Due to the sale of the Montana Refinery, we have reclassified certain amounts previously reported and now report such amounts as from discontinued operations.

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Balance Sheet Data (Unaudited)

	September 30, 2006	December 31, 2005
	(In thousands)	
Cash, cash equivalents and investments in marketable securities	$ 290,457	$ 254,842
Working capital	$ 253,961	$ 210,103
Total assets	$1,228,792	$1,142,900
Stockholders equity	$ 462,738	$ 377,351

Other Financial Data (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In thousands)			
Net cash provided by operating activities	$128,476	$ 90,396	$ 208,271	$ 162,876
Net cash provided by (used for) investing activities	$ (2,786)	$(113,043)	$ 73,342	$(263,466)
Net cash provided by (used for) financing activities	$ (48,918)	$ (12,645)	$(136,049)	$ 109,439
Capital expenditures	$ 21,688	$ 29,417	$ 89,182	$ 58,062
EBITDA from continuing operations (1)	$130,166	$ 104,224	$ 329,801	$ 233,954

(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 3 of Part I of this Form 10-Q.

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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 through June 30, 2005, our segments reflected two business divisions, Refining and HEP. The HEP segment did not have any activity subsequent to the deconsolidation effective July 1, 2005.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In thousands)			
Sales and other revenues [1]				
Refining	$ 1,172,409	$ 880,228	$ 3,084,595	$ 2,216,526
HEP				36,034
Corporate and other	404	417	928	1,034
Consolidations and eliminations	(120)	(125)	(396)	(19,699)
Consolidated	$ 1,172,693	$ 880,520	$ 3,085,127	$ 2,233,895
Income from operations [1]				
Refining	$ 129,775	$ 104,262	$ 338,670	$ 223,182
HEP				16,019
Corporate and other	(12,685)	(12,552)	(45,380)	(33,702)
Consolidated	$ 117,090	$ 91,710	$ 293,290	$ 205,499

(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, 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 other 51% interest in the joint venture from our 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.

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Refining Operating Data (Unaudited)

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 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 3 of Part I of this Form 10-Q.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
Navajo Refinery				
Crude charge (BPD) [(1)]	75,610	73,030	69,520	73,080
Refinery production (BPD) [(2)]	82,190	79,660	76,310	80,470
Sales of produced refined products (BPD)	80,950	80,280	75,680	80,160
Sales of refined products (BPD) [(3)]	96,688	87,830	90,495	89,130
Refinery utilization [(4)]	92.2%	97.4%	89.9%	97.4%
Average per produced barrel [(5)]				
Net sales	$ 84.49	$ 79.18	$ 83.21	$ 67.46
Cost of products [(6)]	68.40	63.07	66.16	54.11
Refinery gross margin	16.09	16.11	17.05	13.35
Refinery operating expenses [(7)]	4.89	3.65	5.00	3.48
Net operating margin	$ 11.20	$ 12.46	$ 12.05	$ 9.87
Feedstocks:				
Sour crude oil	79%	87%	81%	88%
Sweet crude oil	10%	2%	8%	1%
Other feedstocks and blends	11%	11%	11%	11%
Total	100%	100%	100%	100%
Sales of produced refined products:				
Gasolines	58%	57%	59%	58%
Diesel fuels	31%	29%	28%	28%
Jet fuels	3%	4%	4%	4%
Asphalt	3%	5%	3%	6%
LPG and other	5%	5%	6%	4%
Total	100%	100%	100%	100%
Woods Cross Refinery				
Crude charge (BPD) [(1)]	24,360	24,350	24,130	23,970

Refinery production (BPD) (2)	25,790	26,190	25,620	25,760
Sales of produced refined products (BPD)	25,160	27,240	25,320	26,710
Sales of refined products (BPD) (3)	25,860	28,840	26,360	27,960
Refinery utilization (4)	93.7%	93.7%	92.8%	92.2%
Average per produced barrel (5)				
Net sales	$ 94.88	$ 81.72	$ 85.33	$ 68.23
Cost of products (6)	71.82	68.65	67.56	59.26
Refinery gross margin	23.06	13.07	17.77	8.97
Refinery operating expenses (7)	5.18	4.11	5.01	4.18
Net operating margin	$ 17.88	$ 8.96	$ 12.76	$ 4.79

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	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Woods Cross Refinery				
Feedstocks:				
Sour crude oil	0%	7%	3%	8%
Sweet crude oil	92%	81%	89%	81%
Other feedstocks and blends	8%	12%	8%	11%
Total	100%	100%	100%	100%
Sales of produced refined products:				
Gasolines	65%	63%	64%	61%
Diesel fuels	29%	30%	28%	29%
Jet fuels	2%	2%	2%	2%
Fuel oil	4%	4%	5%	6%
LPG and other	0%	1%	1%	2%
Total	100%	100%	100%	100%
Consolidated(8)				
Crude charge (BPD) (1)	99,970	97,380	93,650	97,050
Refinery production (BPD) (2)	107,980	105,850	101,930	106,230
Sales of produced refined products (BPD)	106,110	107,520	101,000	106,870
Sales of refined products (BPD) (3)	122,548	116,670	116,855	117,090
Refinery utilization (4)	92.6%	96.4%	90.6%	96.1%
Average per produced barrel (5)				
Net sales	$ 86.96	$ 79.82	$ 83.74	$ 67.65
Cost of products (6)	69.21	64.48	66.51	55.40
Refinery gross margin	17.75	15.34	17.23	12.25
Refinery operating expenses (7)	4.96	3.77	5.00	3.66
Net operating margin	$ 12.79	$ 11.57	$ 12.23	$ 8.59
Feedstocks:				
Sour crude oil	60%	67%	61%	69%
Sweet crude oil	30%	22%	28%	20%
Other feedstocks and blends	10%	11%	11%	11%
Total	100%	100%	100%	100%

Sales of produced refined products:				
Gasolines	60%	59%	60%	59%
Diesel fuels	30%	29%	28%	28%
Jet fuels	2%	3%	4%	3%
Asphalt	3%	4%	2%	5%
LPG and other	5%	5%	6%	5%
Total	100%	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).

(5) Represents average per barrel amounts for produced refined products

sold, which are non-GAAP. Reconciliations to amounts reported under GAAP are located under Reconciliations to Amounts Reported under Generally Accepted Accounting Principles following Item 3 of Part I of this Form 10-Q.

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

(7) Represents operating expenses of our 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 Three Months Ended September 30, 2006 Compared to Three Months Ended September 30, 2005

Summary

Net income for the three months ended September 30, 2006 was $79.0 million ($1.37 per diluted share) compared to net income of $61.7 million ($0.98 per diluted share) for the three months ended September 30, 2005. Earnings for the third quarter of 2006 as compared to the third quarter of 2005 increased by $17.3 million principally due to improved refined product margins experienced in the current year. Additionally, the start-up of our new ROSE unit (the ROSE unit converts a significant portion of lower value asphalt into high value transportation fuels) in December 2005 contributed to higher refinery yields in the current quarter. Overall refinery production levels from continuing operations showed an increase of 2% in the 2006 third quarter as compared to the same period in 2005 due to an increase in production levels from our recent 75,000 BPSD to 82,000 BPSD capacity expansion at our Navajo Refinery. Refinery gross margins from continuing operations were $17.75 per produced barrel for the third quarter of 2006 compared to margins of $15.34 per produced barrel for the third quarter of 2005.

Sales and Other Revenues

Sales and other revenues increased 33% from $880.5 million for the three months ended September 30, 2005 to $1,172.7 million for the three months ended September 30, 2006, due principally to higher refined product sales prices, combined with the recording of direct sales of crude oil as revenues which began April 1, 2006, and an increase in volumes of refined product sold. The average sales price we received per produced barrel sold increased 9% from $79.82 in the third quarter of 2005 to $86.96 in the third quarter of 2006. The total volume of refined products we sold increased 5% in the third quarter of 2006 as compared to the third quarter of 2005 due to the recent 75,000 BPSD to 82,000 BPSD capacity expansion at our Navajo Refinery in which production levels were gradually increased to full capacity in September and an increase in sales of purchased finished products. The 2006 third quarter increase also includes $143.1 million of revenues attributable to certain excess crude oil sales that were previously netted against the corresponding costs and presented in cost of products sold prior to our adoption of new accounting guidance effective April 1, 2006.

Cost of Products Sold

Cost of products sold increased 35% from $725.3 million in the third quarter of 2005 to $979.3 million in the third quarter of 2006 due principally to higher costs of crude oil, combined with the recording of related costs associated with the direct sales of crude oil which began April 1, 2006, and a 5% increase in refined product volumes sold. The average price we paid per barrel of crude oil and feedstocks purchased and the per barrel transportation costs of moving the finished products to the market place increased 7% from $64.48 for the third quarter of 2005 to $69.21 for the third quarter of 2006. Also, cost of products sold for the 2006 third quarter increased by $142.9 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.

Gross Refinery Margins

Gross refining margin per produced barrel increased 16% from $15.34 for the third quarter of 2005 to $17.75 for the third quarter of 2006. Gross refinery margin does not include the effects of depreciation, depletion or amortization. See Reconciliations to Amounts Reported under Generally Accepted Accounting Principles following Item 3 of Part 1 of this Form 10-Q for a reconciliation to the income statements of prices of refined products sold and costs of products purchased.

Operating Expenses

Operating expenses increased 28% from $42.3 million for the third quarter of 2005 to $54.1 million for the third quarter of 2006 due principally to refinery maintenance projects and increased utility costs.

General and Administrative Expenses

General and administrative expenses were $12.6 million for the third quarter of 2006 and the third quarter of 2005.

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Depreciation, Depletion and Amortization Expenses

Depreciation, depletion and amortization increased 11% from $8.5 million for the third quarter of 2005 to $9.5 million for the third quarter of 2006 due primarily to increased depreciation arising from capitalized refinery improvement projects.

Equity in Earnings of HEP and Minority Interests

As part of the deconsolidation of HEP on July 1, 2005, we show equity in earnings for our ownership percentage of HEP, currently 45%, including any incentive distributions paid with respect to our general partner interest. Our equity in earnings of HEP was $3.6 million and $3.3 million for the three months ended September 30, 2006 and 2005, respectively.

Equity in Earnings of Joint Ventures

There was no equity in earnings of joint ventures for the three months ended September 30, 2006 and 2005 as all previously owned interests in joint ventures have been consolidated in our financials or have been sold.

Interest Income

Interest income for the third quarter of 2006 was $2.7 million compared to $1.2 million for the third quarter of 2005. The increase in interest income was principally due to a higher interest rate environment.

Interest Expense

Interest expense was $0.3 million for the third quarter of 2006 as compared to $0.5 million for the third quarter of 2005.

Income Taxes

Income taxes increased 23% from $35.7 million for the third quarter of 2005 to $44.0 million for the third quarter of 2006 due to significantly higher pre-tax earnings during the 2006 third quarter as compared to the 2005 third quarter, partially offset by a lower effective tax rate. The effective tax rate for the third quarter of 2006 was 35.7%, as compared to 37.3% for the third quarter of 2005. The reduction in the effective tax rate was primarily due to income tax credits available to small business refiners. See below under Planned Capital Expenditures for a discussion of tax benefits available to refiners.

Discontinued Operations

We realized a loss of $0.2 million from discontinued operations for the third quarter of 2006 as compared to income of $1.0 million for the third quarter of 2005. The decrease in earnings from discontinued operations was due largely to the wind down of operations resulting from the sale of the Montana Refinery on March 31, 2006.

Results of Operations Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

Summary

Net income for the nine months ended September 30, 2006 was $218.9 million ($3.73 per diluted share) compared to net income of $127.8 million ($2.00 per diluted share) for the nine months ended September 30, 2005. Earnings for the nine months ended September 30, 2006 as compared to the nine months ended September 30, 2005 increased by $91.1 million principally due to improved refined product margins experienced in the current year, the gain on the sale of the Montana Refinery assets, and the sale of sulfur credits under environmental laws, partially offset by reduced production volumes and higher refinery operating and general and administrative expenses. Additionally, the start-up of our new ROSE unit in December 2005 contributed to higher refinery yields in the current year. Overall refinery production levels from continuing operations showed a decrease of 4% for the nine months ended September 30, 2006 as compared to the same period in 2005. During the nine months ended September 30, 2006, production was reduced due to a power outage at the Navajo Refinery in February 2006 and production downtime arising from planned capital and refinery maintenance projects at the Navajo and Woods Cross Refineries during the second quarter of 2006. Refinery gross margins from continuing operations were $17.23 per produced barrel for the nine months ended September 30, 2006 compared to margins of $12.25 per produced barrel for the nine months ended September 30, 2005.

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Sales and Other Revenues

Sales and other revenues increased 38% from $2,233.9 million for the nine months ended September 30, 2005 to $3,085.1 million for the nine months ended September 30, 2006, due principally to higher refined product sales prices, combined with the recording of direct sales of crude oil as revenues beginning April 1, 2006, partially offset by a small decrease in volumes of refined products sold. The average sales price we received per produced barrel sold increased 24% from $67.65 for the nine months ended September 30, 2005 to $83.74 for the nine months ended September 30 2006. The total volume of refined products we sold for the nine months ended September 30, 2006 was comparable to volumes sold for the same period in 2005. Overall refinery production levels from continuing operations showed a decrease of 4% in the nine months ended September 30, 2006 as compared to the same period in 2005 which was largely offset by an increase in sales of purchased refined products. Refinery production levels were down in the second quarter of 2006 due to downtime arising from planned capital and maintenance projects at both of our refineries. The increase in sales and other revenues for the nine months ended September 30, 2006 also includes $274.4 million of revenues attributable to certain excess crude oil sales that were previously netted against the corresponding costs and presented in cost of products sold prior to our adoption of new accounting guidance on April 1, 2006. Additionally, revenues increased by the sales of $12.0 million of sulfur credits generated because our Navajo Refinery is making gasoline that is substantially lower in sulfur than required by EPA regulations. Revenues were reduced due to the exclusion of the operations of HEP in 2006 after the deconsolidation of HEP effective July 1, 2005, which reduction was partially offset by revenues from the NK Asphalt Partners joint venture (doing business as Holly Asphalt Company) which we included for only part of the nine months ended September 30, 2005, following our February 2005 acquisition of the other partner s interest.

Cost of Products Sold

Cost of products sold increased 40% from $1,828.6 million for the nine months ended September 30, 2005 to $2,562.8 million for the nine months ended September 30, 2006, due principally to higher costs of crude oil, combined with the recording of related costs associated with the direct sales of crude oil beginning April 1, 2006. The average price we paid per barrel of crude oil and feedstocks purchased and the transportation costs of moving the finished products to the market place increased 20% from $55.40 for the first nine months of 2005 to $66.51 for the first nine months of 2006. Also, cost of products sold for the nine months ended September 30, 2006 increased by $273.9 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. Additionally, cost of products sold was reduced due to the exclusion of the operations of HEP in 2006 due to the deconsolidation of HEP effective July 1, 2005, which reduction was partially offset by increases in the current year due to the inclusion of NK Asphalt Partners for the entire nine months ended September 30, 2006 versus only part of the nine months ended September 30, 2005, following our February 2005 acquisition of the other partner s interest.

Gross Refinery Margins

Gross refining margin per produced barrel increased 41% from $12.25 for the first nine months of 2005 to $17.23 for the first nine months of 2006. Gross refinery margin does not include the effects of depreciation, depletion or amortization. See Reconciliations to Amounts Reported under Generally Accepted Accounting Principles following Item 3 of Part 1 of this Form 10-Q for a reconciliation to the income statements of prices of refined products sold and cost of products purchased.

Operating Expenses

Operating expenses increased 18% from $132.0 million for the first nine months of 2005 to $155.7 million for the first nine months of 2006 due principally to refinery maintenance projects, increased utility costs and environmental remediation expenses, 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 26% from $35.5 million for the first nine months of 2005 to $44.8 million for the first nine months of 2006 due primarily to increased equity-based incentive compensation.

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Depreciation, Depletion and Amortization Expenses

Depreciation, depletion and amortization decreased 12% from $31.9 million in the first nine months of 2005 to $28.2 million in the first nine months of 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.

Equity in Earnings of HEP and Minority Interests

As part of the deconsolidation of HEP effective July 1, 2005, we show equity in earnings for our ownership percentage of HEP, currently 45%, including any incentive distributions paid with respect to our general partner interest. Our equity in earnings of HEP was $8.3 million and $3.3 million for the nine months ended September 30, 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 first nine months of 2005 reduced income by $6.7 million.

Equity in Earnings of Joint Ventures

There was no equity in earnings of joint ventures for the nine months ended September 30, 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 nine months ended September 30, 2005 reduced income by $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 first nine months of 2006 was $6.9 million compared to $4.5 million for the first nine months of 2005. The increase in interest income was principally due to a higher interest rate environment.

Interest Expense

Interest expense was $0.8 million for the nine months ended September 30, 2006 as compared to $4.7 million for the nine months ended September 30, 2005. The decrease for this nine month period as compared to the same period in 2005 was principally due to the exclusion of HEP s interest expense for 2006 due to the deconsolidation of HEP effective July 1, 2005.

Income Taxes

Income taxes increased 45% from $75.6 million for the nine months ended September 30, 2005 to $109.6 million for the nine months ended September 30, 2006 due to significantly higher pre-tax earnings for the first nine months of 2006 as compared to the same period in 2005, partially offset by a lower effective tax rate. The effective tax rate for the nine months ended September 30, 2006 was 35.6%, as compared to 37.6% for the nine months ended September 30, 2005. The reduction in the effective tax rate was primarily due to income tax credits available to small business refiners.

Discontinued Operations

Income from discontinued operations was $20.8 million for the nine months ended September 30, 2006 as compared to $1.6 million for the nine months ended September 30, 2005. Included in income for the nine months ended September 30, 2006 was the gain on the sale of the Montana Refinery of $13.8 million, net of $8.2 million in income taxes. The operations of the Montana Refinery generated $7.0 million of earnings for the first nine months of 2006 and $1.6 million for the same period 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.

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 primarily conservative, highly-rated instruments issued by financial institutions or government entities with strong credit ratings.

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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 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 September 30, 2006, we had cash and cash equivalents of $194.6 million, marketable securities with maturities under one year of $88.6 million, marketable securities with maturities greater than one year, but less than two years, of $4.1 million, and one million shares of Connacher stock valued at $3.2 million.

Cash and cash equivalents increased by $145.6 million during the nine months ended September 30, 2006. The cash flow provided by operating activities of $208.3 million and investing activities of $73.3 million, exceeded the cash used for financing activities of $136.0 million. Working capital increased during the nine months ended September 30, 2006 by $43.9 million.

We have a $175 million secured revolving credit facility with Bank of America as administrative agent and a lender, with a term of four years through 2008 and an option to increase the facility to $225 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 September 30, 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 September 30, 2006.

On November 7, 2005, we announced that our Board of Directors authorized the repurchase of up to $200 million of our common stock. 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 nine months ended September 30, 2006, we repurchased under this repurchase initiative 3,743,188 shares at a cost of approximately $140.0 million (of which $3.0 million of the cash settlement was after September 30, 2006) or an average of $37.40 per share. Since inception of this repurchase initiative through September 30, 2006, we have repurchased 4,730,788 shares at a cost of approximately $169.9 million or an average of $35.92 per share.

On October 30, 2006, we announced that our Board of Directors had authorized a $100 million increase in the $200 million common stock repurchase program. The increase raises the authorized repurchase limit under the common stock repurchase program from $200 million to $300 million.

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 our common stock under our current repurchase program. In addition, components of our growth strategy may include selective acquisition of complementary assets for our refining operations that would be 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.

Cash Flows Operating Activities

Net cash flows provided by operating activities amounted to $208.3 million for the nine months ended September 30, 2006, compared to net cash flows provided by operating activities of $162.9 million for the nine months ended

September 30, 2005, a change of $45.4 million. Net income for the nine months ended September 30, 2006 was $218.9 million, an increase of $91.1 million from net income of $127.8 million for the nine months ended September 30, 2005. Additionally, the non-cash items included in the computation of net income depreciation and amortization, deferred taxes, minority interests, equity-based compensation and gain on an asset sale resulted in an increase in cash flows of $16.0 million during the nine months ended September 30, 2006 as compared to an increase in cash flows of $42.8 million for the same period in 2005. Distributions in excess of equity in earnings of Holly Energy Partners and joint ventures increased by $5.0 million for the nine months ended September 30, 2006 as compared to the same period in 2005. Working capital items decreased cash flows by $19.6 million during the nine months ended September 30, 2006, as compared to $5.1 million for the nine months ended September 30, 2005. Inventories increased by $8.4 million in the first nine months of 2006 as compared to $1.3 million for the first nine months of 2005. Additionally, for the first nine months of 2006, there were decreases in both accounts receivable of $13.5 million and accounts payable of $17.3 million, principally due to the sale of the Montana Refinery on March 31, 2006. For the first nine months of 2005, there were increases in both accounts receivable of $199.0 million and accounts payable of $166.6 million, principally due to increases in prices for refined products and crude oil.

Cash Flows Investing Activities and Capital Projects

Net cash flows provided by investing activities were $73.3 million for the nine months ended September 30, 2006, as compared to net cash flows used for investing activities of $263.5 million for the nine months ended September 30, 2005, a net change of $336.8 million. 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. Cash expenditures for property, plant and equipment for the first nine months of 2006 totaled $89.2 million as compared to $58.1 million for the same period of 2005. 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 $21.9 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. Also in February 2005, HEP closed on its Alon transaction which required $120.0 million in cash plus transaction costs of $1.8 million through September 30, 2005. We also invested $172.3 million in marketable securities and received proceeds of $285.9 million from the sale or maturity of marketable securities during the nine months ended September 30, 2006. For the nine months ended September 30, 2005, we invested $254.8 million in marketable securities and received proceeds of $209.4 million from the sale or maturity of marketable securities.

Planned Capital Expenditures

Each year our Board of Directors approves the 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 for capital projects approved in capital budgets for prior years. Our total capital budget for 2006 is approximately $62.2 million, not including the capital projects approved in prior years, mainly our ULSD projects at the Navajo and Woods Cross refineries, as described below. The 2006 capital budget is comprised of $46.9 million for improvement projects for the Navajo Refinery, $4.7 million for projects at the Woods Cross Refinery, $5.1 million for transportation projects, $0.4 million for marketing related projects, $0.7 million for asphalt plant projects and $4.4 million for information technology and other miscellaneous projects. See below for discussion of significant additional planned capital projects at both the Navajo and Woods Cross facilities, which have not yet been approved by our Board of Directors as of the date of this report.

In 2006 we expect to expend approximately $111.0 million on capital projects, which amount primarily consists of certain current year capital budget items and carryovers of capital projects from previous years, less carryovers to 2007 of certain of the currently approved capital projects, combined with certain authorized preliminary expenditures on major capital projects that have not yet been approved.

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We have completed our ULSD project and the first phase of an expansion at the Navajo Refinery. These projects included the expansion / 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 conversion / expansion of the kerosene hydrotreater to naphtha service, the installation of additional sulfur recovery capacity, and the installation of a 10 million standard cubic feet 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 82,000 BPSD. The total cost of these projects was approximately $75 million, which was approved in prior years capital budgets. We plan in the second phase to further increase crude capacity to 85,000 BPSD in the fourth quarter of 2007 by relocating some heat exchangers and replacing some pumps in the Artesia crude unit at an estimated cost of $1 million. An additional 100 ton per day sulfur recovery unit included in the 2006 capital budget will be built at an estimated cost of $26.0 million. This new sulfur recovery unit will permit Navajo to process 100% sour crude and is planned for start-up in the second quarter of 2008. It is anticipated that these projects will also enable the Navajo Refinery, without significant additional investment, to comply with LSG specifications required by the end of 2010.

We have 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 entering into a long term hydrogen contract that has enabled the Woods Cross Refinery to produce ULSD. This project will also create the infrastructure required for the additional Woods Cross project discussed below.

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/or incur additional operating costs to meet applicable requirements.

We have recently announced preliminary plans for significant new capital projects at both our Navajo and Woods Cross refineries to provide feedstock flexibility and expansions of refining capacity at both facilities. These additional planned projects have not at this point been approved by our Board of Directors. The proposed strategy for the Navajo Refinery calls for the installation of a new crude unit, gas oil hydrocracker, solvent de-asphalter and hydrogen plant, which would permit processing up to 100,000 BPSD of crude. The Navajo project would enable us to increase our ability to capture light/heavy crude differentials on 20,000 BPSD. We currently estimate that the cost of the Navajo project would be approximately $240 million and that the project could be completed in the third quarter of 2008. The proposed strategy for the Woods Cross Refinery calls for the expansion and revamp of its crude unit for heavier crudes, the installation of a 10,000 BPSD gas oil hydrotreater which is expandable to 15,000 BPSD and can be converted in the future to a hydrocracker, the expansion and revamp of the solvent de-asphalter to 12,000 BPSD, and the addition of extra sulfur recovery capacity, which would enable processing of up to 30,000 BPSD of crude. Additionally, the Woods Cross project would enable us to increase Canadian heavy/sour crude runs to approximately 20,000 BPSD. This would enable us to take advantage of the wide discounts on Canadian crude when available, and provide a basis for additional crude flexibility and expansion. We currently estimate the cost of the Woods Cross project would be approximately $60 million and that the project could be completed in the third quarter of 2008. The Woods Cross Refinery is required to meet Maximum Achievable Control Technology (MACT) requirements on its FCC flue gas by January 1, 2010. We plan to desulfurize FCC feed prior to this 2010 date to comply with these requirements as well as the future LSG requirements. If we proceed with the projects described above for the Navajo and Woods Cross refineries, we estimate that our total capital expenditures in 2007 and 2008 would be approximately $200 million each year.

To fully take advantage of the economics on the Woods Cross project under consideration, additional crude pipeline capacity would be required to move Canadian crude to the Woods Cross Refinery. We are currently working with HEP to explore options available. We are also working with HEP in evaluating a refined products pipeline from Salt Lake City to Las Vegas.

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 would derive

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from planned capital expenditures associated with the 2004 Act would result in a reduction in our income tax expense of approximately $10.0 million in both 2006 and 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 proposed new Navajo and Woods Cross capital projects would qualify for this deduction.

Cash Flows Financing Activities

Net cash flows used for financing activities were $136.0 million for the nine months ended September 30, 2006, as compared to cash flows provided by financing activities of $109.4 million for the nine months ended September 30, 2005, a net change of $245.5 million. Under our stock repurchase program announced November 7, 2005, we purchased treasury stock of $137.0 million during the nine months ended September 30, 2006. Under our stock repurchase program announced May 19, 2005, we purchased treasury stock of $80.1 million during the nine months ended September 30, 2005. Also, during the nine months ended September 30, 2006 and 2005, we repurchased at current market price from certain executives common stock at a cost of approximately $1.4 million and $0.8 million, respectively; 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. During the nine months ended September 30, 2006, we paid $10.5 million in dividends, received $2.4 million for common stock issued upon exercise of stock options, and recognized $10.4 million in excess tax benefits on our equity based compensation. In connection with HEP s Alon asset acquisition in early 2005, HEP received proceeds of $147.4 million from the issuance of senior notes and paid down borrowings under its credit facility netting to $25.0 million. In connection with HEP s purchase of our intermediate lines in July 2005, HEP received proceeds of $34.6 million from additional issuance of 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 the first nine months of 2005, we paid $8.2 million in dividends, received $2.7 million for common stock issued upon exercise of stock options, made distributions of $9.5 million to the minority interest partners of HEP, incurred $0.9 million of debt issuance costs related to HEP s senior debt and recognized $5.5 million in excess tax benefits on our equity based compensation.

Contractual Obligations and Commitments

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. Under this agreement, we expect minimum annual facility charge payments to be approximately $2.0 million for each of the years beginning in 2009 through 2023.

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 HEP s refined product pipelines or throughput in HEP s terminals a volume of refined products that will result in a minimum level of revenue to HEP of $36.7 million annually. During the nine months ended September 30, 2006, the HEP PTA was amended to reflect certain rate changes, most significantly a re-negotiation of the tariffs on our refined products shipped on the pipelines that serve our Navajo Refinery, but such amendment did not affect our obligations under the minimum revenue commitment. Under the HEP IPA, we agreed to transport volumes of intermediate products on the intermediate pipelines that will result in a minimum level of revenues to HEP of approximately $11.8 million annually. Minimum revenues 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

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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.

As part of our sale of the Montana Refinery, we are subject to potential liabilities, including certain environmental liabilities, relating to the Montana Refinery that may arise due to events and conditions up to the date of sale, subject to a limit of $41 million.

During the nine months ended September 30, 2006, there were no other significant changes in our contractual obligations and commitments.

HEP financed the Alon transaction through a private offering of $150 million principal amount of HEP Senior Notes. HEP increased these notes to $185 million as part of the purchase of our intermediate pipelines. The $185 million HEP Senior Notes are not recorded on our accompanying consolidated balance sheets due to the deconsolidation of HEP effective July 1, 2005. The HEP Senior Notes were reflected on our consolidated balance sheets (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 controlling partner to the extent it makes any payment in satisfaction of $35 million of the principal amount of the HEP Senior Notes.

In discussions beginning in the last half of 2005, the EPA and the State of Utah have asserted that we have liabilities relating to the Federal Clean Air Act at 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 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. With respect to the 2001 Consent Agreement we entered into for our Navajo and Montana refineries, following the sale of the Montana Refinery in March 2006 our remaining commitment relates to the Navajo Refinery and, with the investments made to date, our outstanding required investments are no longer significant.

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.

Our significant accounting policies are described in Item 7. Management s Discussion and Analysis of Financial Conditions and Operations Critical Accounting Policies in our Annual Report on Form 10-K for the year ended December 31, 2005. Certain critical accounting policies that materially affect the amounts recorded in our consolidated financial statements are the use of the LIFO method of valuing certain inventories, the amortization of deferred costs for regular major maintenance and repairs at our refineries, assessing the possible impairment of certain long-lived assets, and assessing contingent liabilities for probable losses. There have been no changes to these policies in 2006.

We use the last-in, first-out (LIFO) method of valuing inventory. 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.

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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.

New Accounting Pronouncements

SFAS No. 151 Inventory Costs, an amendment of ARB No. 43, Chapter 4

In December 2004, the FASB issued SFAS No. 151, Inventory Costs an amendment of ARB No. 43, Chapter 4. This amendment requires abnormal amounts of idle facility expense, freight, handling costs and wasted materials (spoilage) to be recognized as current-period charges. This standard also requires that the allocation of fixed production overhead to the cost of conversion be based on the normal capacity of the production facilities. This standard is effective for fiscal years beginning after June 15, 2005. We have adopted the standard effective beginning January 1, 2006. The adoption of this standard did not have a material effect on our financial condition, results of operations or cash flows.

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 they 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.

With respect to supplying crude oil to our refineries, crude oil is often purchased in locations distant from our refineries and exchanged for crude oil that is transportable to our refineries. These buy/sell exchanges are done in contemplation of one another and allow us to receive the optimal crude blend and quantities at our refineries. All of the crude oil buy/sell transactions done in supplying crude oil to our refineries are recorded as exchanges with the net differential reflected in costs of sales. We also purchase crude oil from producers and other petroleum companies in excess of the needs of our refineries for resale to other purchasers or users of crude oil. With respect to these resales that are in the form of buy/sell exchanges with the same counterparty, the net differential of the exchanges is reflected in costs of products sold. Additionally, certain direct sales of this excess crude oil are made to purchasers or users of crude oil. Under the new accounting guidance, these direct 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 in cost of products sold. Prior to our adoption of EITF 04-13, sales and cost of sales attributable to such excess crude oil direct sales were netted and presented in cost of products sold. During the quarter and nine months ended September 30, 2006, these crude oil sales amounted to $143.1 million and $274.4 million with corresponding costs of $142.9 million and $273.9 million, respectively, resulting in gains on these transactions of $0.2 million and $0.5 million, respectively.

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 are currently evaluating the impact the adoption of this interpretation will have 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

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measurements. This standard is effective for fiscal years beginning after November 15, 2007. We believe the adoption of this standard will not 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 are currently evaluating the impact the adoption of this standard will have on our financial condition, results of operations and cash flows.

ADDITIONAL FACTORS THAT MAY AFFECT FUTURE RESULTS

This discussion should be read in conjunction with the discussion under the heading Risk Factors included in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2005.

Other legal proceedings that could affect future results are described below in Part II, item 1 Legal Proceedings.

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 that 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. Additionally, in 2005 we entered into certain transactions relating to forecasted sales of diesel fuel from our refineries, where our principal objective was 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 (or entered into commodity swap transactions with terms that mirror the futures market). Our objective has been to either 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 has been 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 2005. We have not had any open positions since November 2005.

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

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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.

At September 30, 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 September 30, 2006. We invest a substantial part of available cash 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. We also invest the remainder of 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 our investments are at market rates and interest on borrowings and cash investments 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 3. 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 based upon 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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
	(In thousands)			
Income from continuing operations	$ 79,201	$ 60,686	$ 198,090	$ 126,205
Add provision for income tax	43,964	35,690	109,599	75,602
Add interest expense	268	501	815	4,706
Subtract interest income	(2,747)	(1,202)	(6,890)	(4,455)
Add depreciation, depletion and amortization	9,480	8,549	28,187	31,896
EBITDA from continuing operations	$ 130,166	$ 104,224	$ 329,801	$ 233,954

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 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 both of our refineries on a consolidated basis is calculated as shown below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Average per produced barrel:				
Navajo Refinery				
Net sales	$ 84.49	$ 79.18	$ 83.21	$ 67.46
Less cost of products	68.40	63.07	66.16	54.11
Refinery gross margin	$ 16.09	$ 16.11	$ 17.05	$ 13.35
Woods Cross Refinery				
Net sales	$ 94.88	$ 81.72	$ 85.33	$ 68.23
Less cost of products	71.82	68.65	67.56	59.26
Refinery gross margin	$ 23.06	$ 13.07	$ 17.77	$ 8.97
Consolidated				
Net sales	$ 86.96	$ 79.82	$ 83.74	$ 67.65
Less cost of products	69.21	64.48	66.51	55.40
Refinery gross margin	$ 17.75	$ 15.34	$ 17.23	$ 12.25

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 both of our refineries on a consolidated basis is calculated as shown below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Average per produced barrel:				
Navajo Refinery				
Refinery gross margin	$ 16.09	$ 16.11	$ 17.05	$ 13.35
Less refinery operating expenses	4.89	3.65	5.00	3.48
Net operating margin	$ 11.20	$ 12.46	$ 12.05	$ 9.87
Woods Cross Refinery				

Refinery gross margin	$ 23.06	$ 13.07	$ 17.77	$ 8.97
Less refinery operating expenses	5.18	4.11	5.01	4.18
Net operating margin	$ 17.88	$ 8.96	$ 12.76	$ 4.79
Consolidated				
Refinery gross margin	$ 17.75	$ 15.34	$ 17.23	$ 12.25
Less refinery operating expenses	4.96	3.77	5.00	3.66
Net operating margin	$ 12.79	$ 11.57	$ 12.23	$ 8.59

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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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Navajo Refinery				
Average sales price per produced barrel sold	$ 84.49	$ 79.18	$ 83.21	$ 67.46
Times sales of produced refined products sold (BPD)	80,950	80,280	75,680	80,160
Times number of days in period	92	92	273	273
Refined product sales from produced products sold	$ 629,231	$ 584,804	$ 1,719,172	$ 1,476,273
Woods Cross Refinery				
Average sales price per produced barrel sold	$ 94.88	$ 81.72	$ 85.33	$ 68.23
Times sales of produced refined products sold (BPD)	25,160	27,240	25,320	26,710
Times number of days in period	92	92	273	273
Refined product sales from produced products sold	$ 219,621	$ 204,797	$ 589,832	$ 497,522
Sum of refined products sales from produced products sold from our two refineries (4)	$ 848,852	$ 789,601	$ 2,309,004	$ 1,973,795
Add refined product sales from purchased products and rounding (1)	143,421	67,315	395,664	192,097
Total refined products sales	992,273	856,916	2,704,668	2,165,892
Add direct sales of excess crude oil(2)	143,103		274,378	
Add other refining segment revenue(3)	37,033	23,312	105,549	50,634
Total refining segment revenue	1,172,409	880,228	3,084,595	2,216,526
Add HEP sales and other revenue				36,034
Add corporate and other revenues	404	417	928	1,034
Subtract consolidations and eliminations	(120)	(125)	(396)	(19,699)
Sales and other revenues	$ 1,172,693	$ 880,520	$ 3,085,127	$ 2,233,895

(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.*

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2006	**2005**	**2006**	**2005**
Average sales price per produced barrel sold	$ 86.96	$ 79.82	$ 83.74	$ 67.65
Times sales of produced refined products sold (BPD)	106,110	107,520	101,000	106,870
Times number of days in period	92	92	273	273
Refined product sales from produced products sold	$ 848,852	$ 789,601	$ 2,309,004	$ 1,973,795

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

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Navajo Refinery				
Average cost of products per produced barrel sold	$ 68.40	$ 63.07	$ 66.16	$ 54.11
Times sales of produced refined products sold (BPD)	80,950	80,280	75,680	80,160
Times number of days in period	92	92	273	273
Cost of products for produced products sold	$ 509,402	$ 465,820	$ 1,366,908	$ 1,184,126
Woods Cross Refinery				
Average cost of products per produced barrel sold	$ 71.82	$ 68.65	$ 67.56	$ 59.26
Times sales of produced refined products sold (BPD)	25,160	27,240	25,320	26,710
Times number of days in period	92	92	273	273
Cost of products for produced products sold	$ 166,243	$ 172,042	$ 466,999	$ 432,114
Sum of cost of products for produced products sold from our two refineries (4)	$ 675,645	$ 637,862	$ 1,833,907	$ 1,616,240
Add refined product costs from purchased products sold and rounding (1)	136,241	70,839	394,131	198,150
Total refined cost of products sold	811,886	708,701	2,228,038	1,814,390
Add crude oil cost of direct sales of excess crude oil(2)	142,863		273,924	
Add other refining segment costs of products sold(3)	24,680	16,710	61,237	33,941
Total refining segment cost of products sold	979,429	725,411	2,563,199	1,848,331
Add corporate and other costs				
Subtract consolidations and eliminations	(120)	(125)	(396)	(19,699)
Costs of products sold (exclusive of depreciation, depletion and amortization)	$ 979,309	$ 725,286	$ 2,562,803	$ 1,828,632

(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 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.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2006	**2005**	**2006**	**2005**
Average cost of products per produced barrel sold	$ 69.21	$ 64.48	$ 66.51	$ 55.40
Times sales of produced refined products sold (BPD)	106,110	107,520	101,000	106,870
Times number of days in period	92	92	273	273
Cost of products for produced products sold	$ 675,645	$ 637,862	$ 1,833,907	$ 1,616,240

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Navajo Refinery				
Average refinery operating expenses per produced barrel sold	$ 4.89	$ 3.65	$ 5.00	$ 3.48
Times sales of produced refined products sold (BPD)	80,950	80,280	75,680	80,160
Times number of days in period	92	92	273	273
Refinery operating expenses for produced products sold	$ 36,418	$ 26,958	$ 103,303	$ 76,155
Woods Cross Refinery				
Average refinery operating expenses per produced barrel sold	$ 5.18	$ 4.11	$ 5.01	$ 4.18
Times sales of produced refined products sold (BPD)	25,160	27,240	25,320	26,710
Times number of days in period	92	92	273	273
Refinery operating expenses for produced products sold	$ 11,990	$ 10,300	$ 34,631	$ 30,480
Sum of refinery operating expenses per produced products sold from our two refineries (2)	$ 48,408	$ 37,258	$ 137,934	$ 106,635
Add other refining segment operating expenses and rounding (1)	5,714	5,029	17,731	13,560
Total refining segment operating expenses	54,122	42,287	155,665	120,195
Add HEP operating expenses				11,836
Add corporate and other costs	24		40	
Operating expenses (exclusive of depreciation, depletion and amortization)	$ 54,146	$ 42,287	$ 155,705	$ 132,031

(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.

(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.*

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
Average refinery operating expenses per produced barrel sold	$ 4.96	$ 3.77	$ 5.00	$ 3.66
Times sales of produced refined products sold (BPD)	106,110	107,520	101,000	106,870
Times number of days in period	92	92	273	273
Refinery operating expenses for produced products sold	$ 48,408	$ 37,258	$ 137,934	$ 106,635

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Reconciliation of net operating margin per barrel to refinery gross margin per barrel to total sales and other revenues

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Navajo Refinery				
Net operating margin per barrel	$ 11.20	$ 12.46	$ 12.05	$ 9.87
Add average refinery operating expenses per produced barrel	4.89	3.65	5.00	3.48
Refinery gross margin per barrel	16.09	16.11	17.05	13.35
Add average cost of products per produced barrel sold	68.40	63.07	66.16	54.11
Average sales price per produced barrel sold	$ 84.49	$ 79.18	$ 83.21	$ 67.46
Times sales of produced refined products sold (BPD)	80,950	80,280	75,680	80,160
Times number of days in period	92	92	273	273
Refined products sales from produced products sold	$ 629,231	$ 584,804	$ 1,719,172	$ 1,476,273
Woods Cross Refinery				
Net operating margin per barrel	$ 17.88	$ 8.96	$ 12.76	$ 4.79
Add average refinery operating expenses per produced barrel	5.18	4.11	5.01	4.18
Refinery gross margin per barrel	23.06	13.07	17.77	8.97
Add average cost of products per produced barrel sold	71.82	68.65	67.56	59.26
Average sales price per produced barrel sold	$ 94.88	$ 81.72	$ 85.33	$ 68.23
Times sales of produced refined products sold (BPD)	25,160	27,240	25,320	26,710
Times number of days in period	92	92	273	273
Refined products sales from produced products sold	$ 219,621	$ 204,797	$ 589,832	$ 497,522
Sum of refined products sales from produced products sold from our two refineries (4)	$ 848,852	$ 789,601	$ 2,309,004	$ 1,973,795
Add refined product sales from purchased products and rounding (1)	143,421	67,315	395,664	192,097
Total refined products sales	992,273	856,916	2,704,668	2,165,892
Add direct sales of excess crude oil(2)	143,103		274,378	

Add other refining segment revenue (3)	37,033	23,312	105,549	50,634
Total refining segment revenue	1,172,409	880,228	3,084,595	2,216,526
Add HEP sales and other revenue				36,034
Add corporate and other revenues	404	417	928	1,034
Subtract consolidations and eliminations	(120)	(125)	(396)	(19,699)
Sales and other revenues	$ 1,172,693	$ 880,520	$ 3,085,127	$ 2,233,895

(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.

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Net operating margin per barrel	$ 12.79	$ 11.57	$ 12.23	$ 8.59
Add average refinery operating expenses per produced barrel	4.96	3.77	5.00	3.66
Refinery gross margin per barrel	17.75	15.34	17.23	12.25
Add average cost of products per produced barrel sold	69.21	64.48	66.51	55.40
Average sales price per produced barrel sold	$ 86.96	$ 79.82	$ 83.74	$ 67.65
Times sales of produced refined products sold (BPD)	106,110	107,520	101,000	106,870
Times number of days in period	92	92	273	273
Refined product sales from produced products sold	$ 848,852	$ 789,601	$ 2,309,004	$ 1,973,795

Item 4. 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 quarterly report on Form 10-Q. 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.

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HOLLY CORPORATION
PART II. OTHER INFORMATION

Item 1. 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 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 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 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 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 either have already filed or are expected to file appeals of the adverse rulings to the United States Court of Appeals for the Federal Circuit. 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 and Montana refineries. The tentative settlement agreement,

HOLLY CORPORATION

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 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 late October 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 methyl tertiary butyl ether (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.

The Montana Department of Environmental Quality (MDEQ) has notified us that the MDEQ proposes to seek enforcement of a proposed penalty of $106,000 against us based on alleged violations by the Montana Refinery in late 2004 and early 2005 of certain limitations on sulfur dioxide in the refinery s air emissions permit. The MDEQ has also indicated that it intends to propose additional penalties for alleged violations by the Montana Refinery of the limitations on sulfur dioxide in air emissions in the last two quarters of 2005 and the first quarter of 2006, as well as in the second and third quarters of 2006 when we no longer owned the Montana Refinery as a consequence of our sale of the Montana Refinery to an unrelated purchaser on March 31, 2006. While we do not believe that the air permit for the Montana Refinery should be interpreted as asserted by the MDEQ with respect to most of the alleged violations, we have recently entered into negotiations with the MDEQ 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.

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Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

(c) ***Common Stock Repurchases Made in the Quarter***

On November 7, 2005, we announced that our Board of Directors authorized the repurchase of up to $200.0 million of our common stock. 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. The following table includes the repurchases made during the quarter ended September 30, 2006. The number of shares repurchased prior to our two-for-one stock split effective June 1, 2006 and the per share amounts have been adjusted to reflect the split on a retrospective basis.

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of $200 Million Program	Maximum Dollar Value of Shares Yet to be Purchased as Part of the $200 Million Program (1)
July 2006	224,504	$ 49.04	224,504	$ 68,087,735
August 2006	361,133	$ 49.88	361,133	$ 50,075,963
September 2006	481,898	$ 41.54	481,898	$ 30,057,538
Total	1,067,535	$ 45.94	1,067,535	

(1) Prior to $100 million increase in common stock repurchase program announced October 30, 2006.

The total shares purchased during the third quarter of 2006 reflected herein include 69,742 shares at a total cost of $3.0 million that were not settled until October 2006, and therefore are not included on our cash flow statement for the nine months ended September 30, 2006.

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Item 6. Exhibits

(a) Exhibits

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.

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HOLLY CORPORATION
SIGNATURES

Pursuant to the requirements of the Securities and 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)

Date: November 6, 2006

/s/ P. Dean Ridenour
P. Dean Ridenour
Vice President and Chief Accounting Officer (Principal Accounting Officer)

/s/ Stephen J. McDonnell
Stephen J. McDonnell
Vice President and Chief Financial Officer
(Principal Financial Officer)