Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2011

OR

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

For the transition period from to .

Commission File Number: 1-32225

HOLLY ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**20-0833098**
(State or other jurisdiction of	**(I.R.S. Employer**
incorporation or organization)	**Identification No.)**

2828 N. Harwood, Suite 1300

Dallas, Texas 75201

(Address of principal executive offices)

(214) 871-3555

(Registrant s telephone number, including area code)

100 Crescent Court, Suite 1600, Dallas, Texas 75201-6915

(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 x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer	¨	Accelerated filer	x
Non-accelerated filer	¨	Smaller reporting company	¨

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

The number of the registrant s outstanding common units at July 22, 2011 was 22,078,509.

Table of Contents

HOLLY ENERGY PARTNERS, L.P.

INDEX

Table of Contents

PART I. FINANCIAL INFORMATION

FORWARD-LOOKING STATEMENTS

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 and Liquidity and Capital Resources in Item 2 Management s Discussion and Analysis of Financial Condition and Results of Operations in Part I are forward-looking statements. Forward looking statements use words such as anticipate, project, expect, plan, goal, forecast, intend, believe, may, and similar expressions and statements regarding our plans and objectives for future operations. These statements are based on our beliefs and assumptions and those of our general partner 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 and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give assurance that our expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. Certain factors could cause actual results to differ materially from results anticipated in the forward-looking statements. These factors include, but are not limited to:

- risks and uncertainties with respect to the actual quantities of petroleum products and crude oil shipped on our pipelines and/or terminalled in our terminals;
- the economic viability of HollyFrontier Corporation, Alon USA, Inc. and our other customers;
- the demand for refined petroleum products in markets we serve;
- our ability to successfully purchase and integrate additional operations in the future;
- our ability to complete previously announced or contemplated acquisitions;
- the availability and cost of additional debt and equity financing;
- the possibility of reductions in production or shutdowns at refineries utilizing our pipeline and terminal facilities;
- the effects of current and future government regulations and policies;
- our operational efficiency in carrying out routine operations and capital construction projects;
- 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, the forward-looking statements that are referred to above. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements set forth in our Annual Report on Form 10-K for the year ended December 31, 2010 in Risk Factors and in this Form 10-Q in Management s Discussion and Analysis of Financial Condition and Results of Operations. 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.

Table of Contents

Item 1. Financial Statements

Holly Energy Partners, L.P.

Consolidated Balance Sheets

	June 30, 2011 (Unaudited)	December 31, 2010
	(In thousands, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,402	$ 403
Accounts receivable:		
Trade	2,600	3,544
Affiliates	16,156	18,964
	18,756	22,508
Prepaid and other current assets	1,038	775
Total current assets	21,196	23,686
Properties and equipment, net	445,986	434,950
Transportation agreements, net	105,016	108,489
Goodwill	49,109	49,109
Investment in SLC Pipeline	25,519	25,437
Other assets	4,325	1,602
Total assets	$ 651,151	$ 643,273
LIABILITIES AND PARTNERS EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 3,924	$ 6,347
Affiliates	3,191	3,891
	7,115	10,238
Accrued interest	7,521	7,517
Deferred revenue	5,319	10,437
Accrued property taxes	2,311	1,990
Other current liabilities	956	1,262
Total current liabilities	23,222	31,444
Long-term debt	518,818	491,648
Other long-term liabilities	9,164	10,809
Partners equity:		
Common unitholders (22,078,509 units issued and outstanding at June 30, 2011 and December 31, 2010)	261,014	271,649
General partner interest (2% interest)	(152,595)	(152,251)
Accumulated other comprehensive loss	(8,472)	(10,026)
Total partners equity	99,947	109,372

Total liabilities and partners equity	$ 651,151	$ 643,273

See accompanying notes.

- 4 -

Table of Contents

Holly Energy Partners, L.P.

Consolidated Statements of Income

(Unaudited)

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In thousands, except per unit data)			
Revenues:				
Affiliates	$ 37,139	$ 37,079	$ 71,246	$ 70,676
Third parties	13,801	8,404	24,711	15,503
	50,940	45,483	95,957	86,179
Operating costs and expenses:				
Operations	14,366	13,495	27,162	26,555
Depreciation and amortization	7,713	7,591	15,353	14,801
General and administrative	1,573	1,913	2,936	4,476
	23,652	22,999	45,451	45,832
Operating income	27,288	22,484	50,506	40,347
Other income (expense):				
Equity in earnings of SLC Pipeline	467	544	1,207	1,025
Interest income		2		5
Interest expense	(8,724)	(9,549)	(17,273)	(17,093)
Other expense			(12)	(7)
	(8,257)	(9,003)	(16,078)	(16,070)
Income before income taxes	19,031	13,481	34,428	24,277
State income tax	(18)	(46)	(246)	(140)
Net income	19,013	13,435	34,182	24,137
Less general partner interest in net income, Including incentive distributions	3,847	2,909	7,409	5,555
Limited partners interest in net income	$ 15,166	$ 10,526	$ 26,773	$ 18,582
Limited partners per unit interest in earnings basic and diluted:	$ 0.69	$ 0.48	$ 1.21	$ 0.84
Weighted average limited partners units outstanding	22,079	22,079	22,079	22,079

See accompanying notes.

Holly Energy Partners, L.P.

Consolidated Statements of Cash Flows

(Unaudited)

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In thousands)	
Cash flows from operating activities		
Net income	$ 34,182	$ 24,137
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	15,353	14,801
Equity in earnings of SLC Pipeline, net of distributions	(82)	100
Change in fair value interest rate swaps		1,464
Amortization of restricted and performance units	1,080	1,339
(Increase) decrease in current assets:		
Accounts receivable trade	944	(1,696)
Accounts receivable affiliates	2,808	(2,625)
Prepaid and other current assets	(263)	(200)
Current assets of discontinued operations		2,195
Increase (decrease) in current liabilities:		
Accounts payable trade	(2,423)	(372)
Accounts payable affiliates	(700)	501
Accrued interest	4	4,825
Deferred revenue	(5,118)	2,521
Accrued property taxes	321	(82)
Other current liabilities	(306)	(656)
Other, net	489	(1,066)
Net cash provided by operating activities	46,289	45,186
Cash flows from investing activities		
Additions to properties and equipment	(22,900)	(4,487)
Acquisition of assets from HollyFrontier Corporation		(39,040)
Net cash used for investing activities	(22,900)	(43,527)
Cash flows from financing activities		
Borrowings under credit agreement	64,000	39,000
Repayments of credit agreement borrowings	(37,000)	(90,000)
Proceeds from issuance of senior notes		147,540
Distributions to HEP unitholders	(44,862)	(41,312)
Purchase price in excess of transferred basis in assets acquired from HollyFrontier Corporation		(53,960)
Purchase of units for incentive grants	(1,379)	(2,276)
Deferred financing costs	(3,149)	(353)
Net cash used for financing activities	(22,390)	(1,361)
Cash and cash equivalents		
Increase for the period	999	298

Beginning of period	403	2,508
End of period	$ 1,402	$ 2,806

See accompanying notes.

Table of Contents

Holly Energy Partners, L.P.

Consolidated Statement of Partners Equity

(Unaudited)

	Common Units	General Partner Interest	Accumulated Other Comprehensive Loss	Total
Balance December 31, 2010	$ 271,649	$ (152,251)	$ (10,026)	$ 109,372
Distributions to HEP unitholders	(37,525)	(7,337)		(44,862)
Purchase of units for restricted grants	(1,379)			(1,379)
Amortization of restricted and performance units	1,080			1,080
Comprehensive income:				
Net income	27,189	6,993		34,182
Other comprehensive income			1,554	1,554
Comprehensive income	27,189	6,993	1,554	35,736
Balance June 30, 2011	$ 261,014	$ (152,595)	$ (8,472)	$ 99,947

See accompanying notes.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Note 1: Description of Business and Presentation of Financial Statements

Holly Energy Partners, L.P. (HEP) together with its consolidated subsidiaries, is a publicly held master limited partnership, currently 34% owned (including the 2% general partner interest) by HollyFrontier Corporation (formerly known as Holly Corporation) (HFC) and its subsidiaries. HFC changed its name in connection with the consummation of its merger of equals with Frontier Oil Corporation effective July 1, 2011. All previous references to Holly within these financial statements have been replaced with HFC.

We commenced operations on July 13, 2004 upon the completion of our initial public offering. In these consolidated financial statements, the words we, our, ours and us refer to HEP unless the context otherwise indicates.

We operate in one business segment - the operation of petroleum product and crude oil pipelines and terminals, tankage and loading rack facilities.

We own and operate petroleum product and crude oil pipelines and terminal, tankage and loading rack facilities that support HFC s refining and marketing operations in west Texas, New Mexico, Utah, Oklahoma, Idaho and Arizona. We also own and operate refined product pipelines and terminals, located primarily in Texas, that service Alon USA, Inc. s (Alon) refinery in Big Spring, Texas. Additionally, we own a 25% joint venture interest in a 95-mile intrastate crude oil pipeline system (the SLC Pipeline) that serves refineries in the Salt Lake City area.

We generate revenues by charging tariffs for transporting petroleum products and crude oil through our pipelines, by charging fees for terminalling refined products and other hydrocarbons and storing and providing other services at our storage tanks and terminals. We do not take ownership of products that we transport, terminal or store, and therefore, we are not directly exposed to changes in commodity prices.

The consolidated financial statements included herein have been prepared without audit, pursuant to the rules and regulations of the United States Securities and Exchange Commission (the SEC). The interim financial statements reflect all adjustments, which, in the opinion of management, are necessary for a fair presentation of our results for the interim periods. Such adjustments are considered to be of a normal recurring nature. Although certain notes and other information required by U.S. generally accepted accounting principles (GAAP) 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 Form 10-K for the year ended December 31, 2010. Results of operations for interim periods are not necessarily indicative of the results of operations that will be realized for the year ending December 31, 2011.

Note 2: Acquisitions

2010 Acquisitions

Tulsa East / Lovington Storage Asset Transaction

On March 31, 2010, we acquired from HFC certain storage assets for $88.6 million consisting of hydrocarbon storage tanks having approximately 2 million barrels of storage capacity, a rail loading rack and a truck unloading rack located at HFC s Tulsa refinery east facility.

Also, as part of this same transaction, we acquired HFC s asphalt loading rack facility located at its Navajo refinery facility in Lovington, New Mexico for $4.4 million.

Table of Contents

We are a consolidated variable interest entity of HFC. In accounting for these acquisitions from HFC, we recorded total property and equipment at HFC s cost basis of $39 million and the purchase price in excess of HFC s basis in the assets of $54 million as a decrease to our partners equity.

Note 3: Financial Instruments

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, debt and an interest rate swap. The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the short-term maturity of these instruments.

Our debt consists of borrowings outstanding under our $275 million revolving credit agreement (the Credit Agreement), our 6.25% senior notes due 2015 (the 6.25% Senior Notes) and our 8.25% senior notes due 2018 (the 8.25% Senior Notes). The $186 million carrying amount of borrowings outstanding under the Credit Agreement approximates fair value as interest rates are reset frequently using current rates. The estimated fair values of our 6.25% Senior Notes and 8.25% Senior Notes were $184.1 million and $159.4 million, respectively, at June 30, 2011. These fair value estimates are based on market quotes provided from a third-party bank. See Note 7 for additional information on these instruments.

Fair Value Measurements

Fair value measurements are derived using inputs (assumptions that market participants would use in pricing an asset or liability) including assumptions about risk. GAAP categorizes inputs used in fair value measurements into three broad levels as follows:

(Level 1) Quoted prices in active markets for identical assets or liabilities.

(Level 2) Observable inputs other than quoted prices included in Level 1, such as quoted prices for similar assets and liabilities in active markets, similar assets and liabilities in markets that are not active or can be corroborated by observable market data.

(Level 3) Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. This includes valuation techniques that involve significant unobservable inputs.

We have an interest rate swap that is measured at fair value on a recurring basis using Level 2 inputs that as of June 30, 2011 represented a liability having a fair value of $8.5 million. With respect to this instrument, fair value is based on the net present value of expected future cash flows related to both variable and fixed rate legs of our interest rate swap agreement. Our measurement is computed using the forward London Interbank Offered Rate (LIBOR) yield curve, a market-based observable input. See Note 7 for additional information on our interest rate swap.

Note 4: Properties and Equipment

	June 30, 2011	December 31, 2010
	(In thousands)	
Pipelines and terminals	$ 510,488	$ 507,260
Land and right of way	25,271	25,264
Other	15,427	14,591
Construction in progress	35,391	16,601
	586,577	563,716
Less accumulated depreciation	140,591	128,766
	$ 445,986	$ 434,950

We capitalized $0.5 million and $0.2 million in interest related to major construction projects during the six months ended June 30, 2011 and 2010, respectively.

Table of Contents

Note 5: Transportation Agreements

Our transportation agreements consist of the following:

The Alon pipelines and terminals agreement (the Alon PTA) represents a portion of the total purchase price of the Alon assets acquired in 2005 that was allocated based on an estimated fair value derived under an income approach. This asset is being amortized over 30 years ending 2035, the 15-year initial term of the Alon PTA plus the expected 15-year extension period.

The HFC crude pipelines and tankage agreement (the HFC CPTA) represents a portion of the total purchase price of certain crude pipelines and tankage assets acquired from HFC in 2008 (at which time we were not a consolidated variable interest entity of HFC) that was allocated using a fair value based on the agreement s expected contribution to our future earnings under an income approach. This asset is being amortized over 15 years ending 2023, the 15-year term of the HFC CPTA.

The carrying amounts of our transportation agreements are as follows:

	June 30, 2011	December 31, 2010
	(In thousands)	
Alon transportation agreement	$ 59,933	$ 59,933
HFC crude pipelines and tankage agreement	74,231	74,231
	134,164	134,164
Less accumulated amortization	29,148	25,675
	$ 105,016	$ 108,489

We have additional transportation agreements with HFC that relate to assets contributed to us or acquired from HFC consisting of pipeline, terminal and tankage assets. These transactions occurred while we were a consolidated variable interest entity of HFC, therefore, our basis in these agreements does not reflect a step-up in basis to fair value.

In addition, we have an agreement to provide transportation and storage services to HFC via our Tulsa logistics and storage assets acquired from Sinclair. Since this agreement is with HFC and not between Sinclair and us, there is no purchase price allocation attributable to this agreement.

Note 6: Employees, Retirement and Incentive Plans

Employees who provide direct services to us are employed by Holly Logistic Services, L.L.C., a HFC subsidiary. Their costs, including salaries, bonuses, payroll taxes, benefits and other direct costs are charged to us monthly in accordance with an omnibus agreement that we have with HFC. These employees participate in the retirement and benefit plans of HFC. Our share of retirement and benefit plan costs was $0.7 million and $0.6 million for the three months ended June 30, 2011 and 2010, respectively, and $1.4 million and $1.3 million for the six months ended June 30, 2011 and June 30, 2010, respectively.

We have adopted an incentive plan (Long-Term Incentive Plan) for employees, consultants and non-employee directors who perform services for us. The Long-Term Incentive Plan consists of four components: restricted units, performance units, unit options and unit appreciation rights.

Table of Contents

As of June 30, 2011, we have two types of equity-based compensation, which are described below. The compensation cost charged against income for these plans was $0.4 million and $0.3 million for the three months ended June 30, 2011 and 2010, respectively, and $1.1 million and $1.3 million for the six months ended June 30, 2011 and 2010, respectively. We currently purchase units in the open market instead of issuing new units for the settlement of all unit awards under our Long-Term Incentive Plan. At June 30, 2011, 350,000 units were authorized to be granted under the equity-based compensation plans, of which 83,254 had not yet been granted, assuming no forfeitures of the unvested units and full achievement of goals for the performance units already granted.

Restricted Units

Under our Long-Term Incentive Plan, we grant restricted units to selected employees and directors who perform services for us, with vesting generally over a period of one to five years. Although full ownership of the units does not transfer to the recipients until the units vest, the recipients have distribution and voting rights on these units from the date of grant. The fair value of each restricted unit award is measured at the market price as of the date of grant and is amortized over the vesting period.

A summary of restricted unit activity and changes during the six months ended June 30, 2011 is presented below:

Restricted Units	Grants	Weighted-Average Grant-Date Fair Value	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value ($000)
Outstanding at January 1, 2011 (nonvested)	47,295	$ 37.47		
Granted	17,780	59.65		
Vesting and transfer of full ownership to recipients	(24,055)	41.48		
Forfeited	(7,802)	48.29		
Outstanding at June 30, 2011 (nonvested)	33,218	$ 44.97	1 year	$ 1,803

The fair value of restricted units that were vested and transferred to recipients during the six months ended June 30, 2011 and 2010 were $1 million and $1.5 million, respectively. As of June 30, 2011, there was $0.7 million of total unrecognized compensation costs related to nonvested restricted unit grants. That cost is expected to be recognized over a weighted-average period of 1 year.

Performance Units

Under our Long-Term Incentive Plan, we grant performance units to selected executives who perform services for us. Performance units granted in 2011 and 2010 are payable based upon the growth in our distributable cash flow per common unit over the performance period, and vest over a period of three years. Performance units granted in 2009 are payable based upon the growth in distributions on our common units during the requisite period, and vest over a period of three years. As of June 30, 2011, estimated share payouts for outstanding nonvested performance unit awards ranged from 110% to 120%.

We granted 8,969 performance units to certain officers in March 2011. These units will vest over a three-year performance period ending December 31, 2013 and are payable in HEP common units. The number of units actually earned will be based on the growth of our distributable cash flow per common unit over the performance period, and can range from 50% to 150% of the number of performance units granted. The fair value of these performance units is based on the grant date closing unit price of $59.65 and will apply to the number of units ultimately awarded.

Table of Contents

A summary of performance unit activity and changes during the six months ended June 30, 2011 is presented below:

Performance Units	Payable In Units
Outstanding at January 1, 2011 (nonvested)	59,415
Granted	8,969
Vesting and transfer of common units to recipients	(14,337)
Forfeited	
Outstanding at June 30, 2011 (nonvested)	54,047

The fair value of performance units vested and transferred to recipients during the six months ended June 30, 2011 and 2010 was $0.6 million and $0.5 million, respectively. Based on the weighted average grant-date fair value, there were $1 million of total unrecognized compensation costs related to nonvested performance units at June 30, 2011. That cost is expected to be recognized over a weighted-average period of 1.1 years.

During the six months ended June 30, 2011, we paid $1.4 million for the purchase of our common units in the open market for the issuance and settlement of all unit awards under our Long-Term Incentive Plan.

Note 7: Debt

Credit Agreement

We have a $275 million Credit Agreement that is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. It is also available to fund letters of credit up to a $50 million sub-limit and to fund distributions to unitholders up to a $30 million sub-limit. In February 2011, we amended our previous credit agreement (expiring in August 2011), extending the expiration date and slightly reducing the size of the credit facility from $300 million to $275 million. The size was reduced based on management s review of past and forecasted utilization of the facility. The Credit Agreement expires in February 2016; however, in the event that the 6.25% Senior Notes are not repurchased, refinanced, extended or repaid prior to September 1, 2014, the Credit Agreement shall expire on that date.

During the six months ended June 30, 2011, we received advances totaling $64 million and repaid $37 million, resulting in net borrowings of $27 million under the Credit Agreement and an outstanding balance of $186 million at June 30, 2011.

Our obligations under the Credit Agreement are collateralized by substantially all of our assets. Indebtedness under the Credit Agreement is recourse to HEP Logistics Holdings, L.P., our general partner, and guaranteed by our material, wholly-owned subsidiaries. Any recourse to HEP Logistics Holdings, L.P. would be limited to the extent of its assets, which other than its investment in us, are not significant.

We may prepay all loans at any time without penalty, except for payment of certain breakage and related costs.

Indebtedness under the Credit Agreement bears interest, at our option, at either (a) the reference rate as announced by the administrative agent plus an applicable margin (ranging from 1.00% to 2.00%) or (b) at a rate equal to LIBOR plus an applicable margin (ranging from 2.00% to 3.00%). In each case, the applicable margin is based upon the ratio of our funded debt (as defined in the Credit Agreement) to EBITDA (earnings before interest, taxes, depreciation and amortization, as defined in the Credit Agreement). We incur a commitment fee on the unused portion of the Credit Agreement at an annual rate ranging from 0.375% to 0.50% based upon the ratio of our funded debt to EBITDA for the four most recently completed fiscal quarters.

Table of Contents

The Credit Agreement imposes certain requirements on us which we are subject to and currently in compliance with, including: a prohibition against distribution to unitholders if, before or after the distribution, a potential default or an event of default as defined in the agreement would occur; limitations on our ability to incur debt, make loans, acquire other companies, change the nature of our business, enter a merger or consolidation, or sell assets; and covenants that require maintenance of a specified EBITDA to interest expense ratio, total debt to EBITDA ratio and senior debt to EBITDA ratio. If an event of default exists under the Credit Agreement, the lenders will be able to accelerate the maturity of the debt and exercise other rights and remedies.

Senior Notes

In March 2010, we issued $150 million in aggregate principal amount outstanding of 8.25% Senior Notes maturing March 15, 2018. A portion of the $147.5 million in net proceeds received was used to fund our $93 million purchase of the Tulsa and Lovington storage assets from HFC on March 31, 2010. Additionally, we used a portion to repay $42 million in outstanding Credit Agreement borrowings, with the remaining proceeds available for general partnership purposes, including working capital and capital expenditures.

Our 6.25% Senior Notes having an aggregate principal amount outstanding of $185 million mature March 1, 2015 and are registered with the SEC. The 6.25% Senior Notes and 8.25% Senior Notes (collectively, the Senior Notes) are unsecured and have certain restrictive covenants, which we are subject to and currently in compliance with, including limitations on our ability to incur additional indebtedness, make investments, sell assets, incur certain liens, pay distributions, enter into transactions with affiliates, and enter into mergers. At any time when the Senior Notes are rated investment grade by both Moody s and Standard & Poor s and no default or event of default exists, we will not be subject to many of the foregoing covenants. Additionally, we have certain redemption rights under the Senior Notes.

Indebtedness under the Senior Notes is recourse to HEP Logistics Holdings, L.P., our general partner, and guaranteed by our wholly-owned subsidiaries. However, any recourse to HEP Logistics Holdings, L.P. would be limited to the extent of its assets, which other than its investment in us, are not significant.

The carrying amounts of our debt are as follows:

	June 30, 2011	December 31, 2010
	(In thousands)	
Credit Agreement	$ 186,000	$ 159,000
6.25% Senior Notes		
Principal	185,000	185,000
Unamortized discount	(1,394)	(1,584)
Unamortized premium dedesignated fair value hedge	1,271	1,444
	184,877	184,860
8.25% Senior Notes		
Principal	150,000	150,000
Unamortized discount	(2,059)	(2,212)
	147,941	147,788
Total long-term debt	$ 518,818	$ 491,648

Interest Rate Risk Management

We use interest rate swaps (derivative instruments) to manage our exposure to interest rate risk.

As of June 30, 2011, we have an interest rate swap that hedges our exposure to the cash flow risk caused by the effects of LIBOR changes on a $155 million Credit Agreement advance. This interest rate swap effectively converts $155 million of LIBOR based debt to fixed rate debt having an interest rate of 3.74% plus an applicable margin, currently 2.50%, which equals an effective interest rate of 6.24% as of June 30, 2011. This swap contract matures in February 2013.

Table of Contents

We have designated this interest rate swap as a cash flow hedge. Based on our assessment of effectiveness using the change in variable cash flows method, we have determined that this interest rate swap is effective in offsetting the variability in interest payments on $155 million of our variable rate debt resulting from changes in LIBOR. Under hedge accounting, we adjust our cash flow hedge on a quarterly basis to its fair value with the offsetting fair value adjustment to accumulated other comprehensive loss. Also on a quarterly basis, we measure hedge effectiveness by comparing the present value of the cumulative change in the expected future interest to be paid or received on the variable leg of our swap against the expected future interest payments on $155 million of our variable rate debt. Any ineffectiveness is reclassified from accumulated other comprehensive loss to interest expense. To date, we have had no ineffectiveness on our cash flow hedge.

Additional information on our interest rate swap is as follows:

Derivative Instrument	Balance Sheet Location	Fair Value	Location of Offsetting Balance	Offsetting Amount
		(In thousands)		
June 30, 2011				
Interest rate swap designated as cash flow hedging instrument:				
Variable-to-fixed interest rate swap contract ($155 million of LIBOR based debt interest)	Other long-term liabilities	$ 8,472	Accumulated other comprehensive loss	$ 8,472
December 31, 2010				
Interest rate swap designated as cash flow hedging instrument:				
Variable-to-fixed interest rate swap contract ($155 million of LIBOR based debt interest)	Other long-term liabilities	$ 10,026	Accumulated other comprehensive loss	$ 10,026

Interest Expense and Other Debt Information

Interest expense consists of the following components:

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In thousands)	
Interest on outstanding debt:		
Credit Agreement, net of interest on interest rate swap	$ 5,013	$ 4,726
6.25% Senior Notes, net of interest on interest rate swaps	5,781	5,623
8.25% Senior Notes	6,187	3,816
Partial settlement of interest rate swap cash flow hedge		1,076
Net fair value adjustments to interest rate swaps (1)		1,464
Net amortization of discount and deferred debt issuance costs	595	458
Commitment fees	227	177
Total interest incurred	17,803	17,340
Less capitalized interest	530	247
Net interest expense	$ 17,273	$ 17,093
Cash paid for interest (2)	$ 17,204	$ 14,192

(1) Represents fair value adjustments to interest rate swap agreements settled during the first quarter of 2010.

(2) Net of cash received under previous interest rate swap agreements of $1.9 million for the six months ended June 30, 2010.

Note 8: Significant Customers

All revenues are domestic revenues, of which 96% are currently generated from our two largest customers: HFC and Alon. The vast majority of our revenues are derived from activities conducted in the southwest United States.

Table of Contents

The following table presents the percentage of total revenues generated by each of these customers:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
HFC	73%	82%	74%	82%
Alon	23%	14%	22%	14%

(1) The Alon PTA was amended in June 2011, limiting the carryover term of credits attributable to Alon s shortfall payments to the calendar year end in which the shortfalls occur. As a result, we recognized an additional $2.4 million of previously deferred revenues during the three months ended June 30, 2011 that relate to shortfall billings for the third and fourth quarters of 2010.

Note 9: Related Party Transactions

HFC Agreements

We serve HFC s refineries in New Mexico, Utah and Oklahoma under the following long-term pipeline and terminal, tankage and throughput agreements:

HFC PTA (pipelines and terminals throughput agreement expiring in 2019 that relates to assets contributed to us by HFC upon our initial public offering in 2004);

HFC IPA (intermediate pipelines throughput agreement expiring in 2024 that relates to assets acquired from HFC in 2005 and 2009);

HFC CPTA (crude pipelines and tankage throughput agreement expiring in 2023 that relates to assets acquired from HFC in 2008);

HFC PTTA (pipeline, tankage and loading rack throughput agreement expiring in 2024 that relates to the Tulsa east facilities acquired from Sinclair in 2009 and from HFC in March 2010);

HFC RPA (pipeline throughput agreement expiring in 2024 that relates to the Roadrunner Pipeline acquired from HFC in 2009);

HFC ETA (equipment and throughput agreement expiring in 2024 that relates to the Tulsa west facilities acquired from HFC in 2009);

HFC NPA (natural gas pipeline throughput agreement expiring in 2024); and

HFC ATA (asphalt loading rack throughput agreement expiring in 2025 that relates to the Lovington rack facility acquired from HFC in March 2010).

Under these agreements, HFC agreed to transport, store and throughput volumes of refined product and crude oil on our pipelines and terminal, tankage and loading rack facilities that result in minimum annual payments to us. These minimum annual payments or revenues are subject to annual tariff rate adjustments on July 1, based on the Producer Price Index (PPI) or Federal Energy Regulatory Commission (FERC) index. As of July 1, 2011, these agreements with HFC will result in minimum annualized payments to us of $140 million.

If HFC fails to meet its minimum volume commitments under the agreements in any quarter, it will be required to pay us in cash the amount of any shortfall by the last day of the month following the end of the quarter. A shortfall payment under the HFC PTA and HFC IPA may be applied as a credit in the following four quarters after minimum obligations are met.

Under certain provisions of an omnibus agreement we have with HFC (the Omnibus Agreement) we pay HFC an annual administrative fee for the provision by HFC or its affiliates of various general and administrative services to us, currently $2.3 million. This fee does not include the salaries of pipeline and terminal personnel or the cost of their employee benefits, which are charged to us separately by HFC. Also, we reimburse HFC and its affiliates for direct expenses they incur on our behalf.

Table of Contents

Related party transactions with HFC are as follows:

Revenues received from HFC were $37.1 million for the three months ended June 30, 2011 and 2010, and $71.2 million and $70.7 million for the six months ended June 30, 2011 and 2010, respectively.

HFC charged general and administrative services under the Omnibus Agreement of $0.6 million for the three months ended June 30, 2011 and 2010 and $1.2 million for the six months ended June 30, 2011 and 2010.

We reimbursed HFC for costs of employees supporting our operations of $4.7 million and $4.6 million for the three months ended June 30, 2011 and 2010, respectively, and $9.7 million and $8.8 million for the six months ended June 30, 2011 and 2010, respectively.

We distributed $10 million and $8.8 million for the three months ended June 30, 2011 and 2010, respectively, to HFC as regular distributions on its common units, and general partner interest, including general partner incentive distributions. We distributed $19.7 million and $17.4 million for the six months ended June 30, 2011 and 2010, respectively.

Accounts receivable from HFC were $16.2 million and $19 million at June 30, 2011 and December 31, 2010, respectively.

Accounts payable to HFC were $3.2 million and $3.9 million at June 30, 2011 and December 31, 2010, respectively.

Revenues for the three and the six months ended June 30, 2011 include $0.7 million and $1.9 million, respectively, of shortfalls billed under the HFC IPA in 2010, as HFC did not exceed its minimum volume commitment in any of the subsequent four quarters. Deferred revenue in the consolidated balance sheets at June 30, 2011 and December 31, 2010, includes $3.9 million and $3.3 million, respectively, relating to the HFC IPA. It is possible that HFC may not exceed its minimum obligations under the HFC IPA to allow HFC to receive credit for any of the $3.9 million deferred at June 30, 2011.

We acquired certain storage assets and an asphalt loading rack facility from HFC in March 2010. See Note 2 for a description of this transaction.

Note 10: Partners   Equity

HFC currently holds 7,290,000 of our common units and the 2% general partner interest, which together constitutes a 34% ownership interest in us.

In May 2010, all of the conditions necessary to end the subordination period for the 937,500 Class B subordinated units originally issued to Alon in connection with our acquisition of assets from Alon in 2005 were met and the units were converted into our common units on a one-for-one basis. These subordinated units were not publicly traded.

Under our registration statement filed with the SEC using a   shelf   registration process, we currently have the ability to raise $860 million through security offerings, through one or more prospectus supplements that would describe, among other things, the specific amounts, prices and terms of any securities offered and how the proceeds would be used. Any proceeds from the sale of securities would be used for general business purposes, which may include, among other things, funding acquisitions of assets or businesses, working capital, capital expenditures, investments in subsidiaries, the retirement of existing debt and/or the repurchase of common units or other securities.

Table of Contents

Allocations of Net Income

Net income attributable to Holly Energy Partners, L.P. is allocated between limited partners and the general partner interest in accordance with the provisions of the partnership agreement. HEP net income allocated to the general partner includes incentive distributions that are declared subsequent to quarter end. After the amount of incentive distributions is allocated to the general partner, the remaining net income attributable to HEP is allocated to the partners based on their weighted-average ownership percentage during the period.

The following table presents the allocation of the general partner interest in net income for the periods presented below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In thousands, except per unit data)			
General partner interest in net income	$ 310	$ 220	$ 547	$ 388
General partner incentive distribution	3,537	2,689	6,862	5,167
Total general partner interest in net income attributable to HEP	$ 3,847	$ 2,909	$ 7,409	$ 5,555

Cash Distributions

Our general partner, HEP Logistics Holdings, L.P., is entitled to incentive distributions if the amount we distribute with respect to any quarter exceeds specified target levels.

On July 27, 2011, we announced our cash distribution for the second quarter of 2011 of $0.865 per unit. The distribution is payable on all common and general partner units and will be paid August 12, 2011 to all unitholders of record on August 8, 2011.

The following table presents the allocation of our regular quarterly cash distributions to the general and limited partners for the periods in which they apply. Our distributions are declared subsequent to quarter end; therefore, the amounts presented do not reflect distributions paid during the periods presented below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In thousands, except per unit data)			
General partner interest	$ 462	$ 427	$ 915	$ 844
General partner incentive distribution	3,537	2,689	6,862	5,167
Total general partner distribution	3,999	3,116	7,777	6,011
Limited partner distribution	19,098	18,215	37,975	36,209
Total regular quarterly cash distribution	$ 23,097	$ 21,331	$ 45,752	$ 42,220
Cash distribution per unit applicable to limited partners	$ 0.865	$ 0.825	$ 1.720	$ 1.640

As a master limited partnership, we distribute our available cash, which historically has exceeded our net income because depreciation and amortization expense represents a non-cash charge against income. The result is a decline in our equity since our regular quarterly distributions have exceeded our quarterly net income. Additionally, if the assets contributed and acquired from HFC had occurred while we were not a consolidated variable interest entity of HFC, our acquisition cost in excess of HFC s historical basis in the transferred assets of $218 million would have been recorded in our financial statements as increases to our properties and equipment and intangible assets instead of decreases to our partners equity.

Table of Contents

Comprehensive Income

We have other comprehensive income resulting from fair value adjustments to our cash flow hedge. Our comprehensive income is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In thousands)			
Net income	$ 19,013	$ 13,435	$ 34,182	$ 24,137
Other comprehensive income (loss):				
Change in fair value of cash flow hedge	271	(1,696)	1,554	(3,057)
Reclassification adjustment to net income on partial settlement of cash flow hedge		1,076		1,076
Other comprehensive income (loss)	271	(620)	1,554	(1,981)
Comprehensive income	$ 19,284	$ 12,815	$ 35,736	$ 22,156

Note 11: Supplemental Guarantor/Non-Guarantor Financial Information

Obligations of Holly Energy Partners, L.P. (Parent) under the 6.25% Senior Notes and 8.25% Senior Notes have been jointly and severally guaranteed by each of its direct and indirect wholly-owned subsidiaries (Guarantor Subsidiaries). These guarantees are full and unconditional.

The following financial information presents condensed consolidating balance sheets, statements of income, and statements of cash flows of the Parent and the Guarantor Subsidiaries. The information has been presented as if the Parent accounted for its ownership in the Guarantor Subsidiaries using the equity method of accounting.

Table of Contents

Condensed Consolidating Balance Sheet

June 30, 2011	**Parent**	**Guarantor Subsidiaries**	**Eliminations**	**Consolidated**
		(In thousands)		
ASSETS				
Current assets:				
Cash and cash equivalents	$ 2	$ 1,400	$	$ 1,402
Accounts receivable		18,756		18,756
Intercompany accounts receivable (payable)	(151,277)	151,277		
Prepaid and other current assets	73	965		1,038
Total current assets	(151,202)	172,398		21,196
Properties and equipment, net		445,986		445,986
Investment in subsidiaries	590,944		(590,944)	
Transportation agreements, net		105,016		105,016
Goodwill		49,109		49,109
Investment in SLC Pipeline		25,519		25,519
Other assets	1,156	3,169		4,325
Total assets	$ 440,898	$ 801,197	$ (590,944)	$ 651,151
LIABILITIES AND PARTNERS EQUITY				
Current liabilities:				
Accounts payable	$	$ 7,115	$	$ 7,115
Accrued interest	7,498	23		7,521
Deferred revenue		5,319		5,319
Accrued property taxes		2,311		2,311
Other current liabilities	635	321		956
Total current liabilities	8,133	15,089		23,222
Long-term debt	332,818	186,000		518,818
Other long-term liabilities		9,164		9,164
Partners equity	99,947	590,944	(590,944)	99,947
Total liabilities and partners equity	$ 440,898	$ 801,197	$ (590,944)	$ 651,151

Condensed Consolidating Balance Sheet

December 31, 2010	**Parent**	**Guarantor Subsidiaries**	**Eliminations**	**Consolidated**
		(In thousands)		
ASSETS				
Current assets:				
Cash and cash equivalents	$ 2	$ 401	$	$ 403
Accounts receivable		22,508		22,508
Intercompany accounts receivable (payable)	(92,230)	92,230		
Prepaid and other current assets	235	540		775

Total current assets	(91,993)	115,679		23,686
Properties and equipment, net		434,950		434,950
Investment in subsidiaries	541,262		(541,262)	
Transportation agreements, net		108,489		108,489
Goodwill		49,109		49,109
Investment in SLC Pipeline		25,437		25,437
Other assets	1,261	341		1,602
Total assets	$ 450,530	$ 734,005	$ (541,262)	$ 643,273
LIABILITIES AND PARTNERS EQUITY				
Current liabilities:				
Accounts payable	$	$ 10,238	$	$ 10,238
Accrued interest	7,498	19		7,517
Deferred revenue		10,437		10,437
Accrued property taxes		1,990		1,990
Other current liabilities	1,011	251		1,262
Total current liabilities	8,509	22,935		31,444
Long-term debt	332,649	158,999		491,648
Other long-term liabilities		10,809		10,809
Partners equity	109,372	541,262	(541,262)	109,372
Total liabilities and partners equity	$ 450,530	$ 734,005	$ (541,262)	$ 643,273

Table of Contents

Condensed Consolidating Statement of Income

Three Months Ended June 30, 2011	Parent	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Revenues:				
Affiliates	$	$ 37,139	$	$ 37,139
Third parties		13,801		13,801
		50,940		50,940
Operating costs and expenses:				
Operations		14,366		14,366
Depreciation and amortization		7,713		7,713
General and administrative	952	621		1,573
	952	22,700		23,652
Operating income (loss)	(952)	28,240		27,288
Equity in earnings of subsidiaries	26,086		(26,086)	
Equity in earnings of SLC Pipeline		467		467
Interest income (expense)	(6,121)	(2,603)		(8,724)
	19,965	(2,136)	(26,086)	(8,257)
Income before income taxes	19,013	26,104	(26,086)	19,031
State income tax		(18)		(18)
Net income	$ 19,013	$ 26,086	$ (26,086)	$ 19,013

Condensed Consolidating Statement of Income

Three Months Ended June 30, 2010	Parent	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Revenues:				
Affiliates	$	$ 37,079	$	$ 37,079
Third parties		8,404		8,404
		45,483		45,483
Operating costs and expenses:				
Operations		13,495		13,495
Depreciation and amortization		7,591		7,591
General and administrative	1,281	632		1,913
	1,281	21,718		22,999
Operating income (loss)	(1,281)	23,765		22,484

Equity in earnings of subsidiaries	20,833		(20,833)	
Equity in earnings of SLC Pipeline		544		544
Interest income (expense)	(6,117)	(3,430)		(9,547)
	14,716	(2,886)	(20,833)	(9,003)
Income before income taxes	13,435	20,879	(20,833)	13,481
State income tax		(46)		(46)
Net income	$ 13,435	$ 20,833	$ (20,833)	$ 13,435

- 20 -

Table of Contents

Condensed Consolidating Statement of Income

Six Months Ended June 30, 2011	Parent	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Revenues:				
Affiliates	$	$ 71,246	$	$ 71,246
Third parties		24,711		24,711
		95,957		95,957
Operating costs and expenses:				
Operations		27,162		27,162
Depreciation and amortization		15,353		15,353
General and administrative	1,703	1,233		2,936
	1,703	43,748		45,451
Operating income (loss)	(1,703)	52,209		50,506
Equity in earnings of subsidiaries	48,128		(48,128)	
Equity in earnings of SLC Pipeline		1,207		1,207
Interest income (expense)	(12,243)	(5,030)		(17,273)
Other		(12)		(12)
	35,885	(3,835)	(48,128)	(16,078)
Income before income taxes	34,182	48,374	(48,128)	34,428
State income tax		(246)		(246)
Net income	$ 34,182	$ 48,128	$ (48,128)	$ 34,182

Condensed Consolidating Statement of Income

Six Months Ended June 30, 2010	Parent	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Revenues:				
Affiliates	$	$ 70,676	$	$ 70,676
Third parties		15,503		15,503
		86,179		86,179
Operating costs and expenses:				
Operations		26,555		26,555
Depreciation and amortization		14,801		14,801
General and administrative	3,082	1,394		4,476
	3,082	42,750		45,832

Operating income (loss)	(3,082)	43,429		40,347
Equity in earnings of subsidiaries	38,318		(38,318)	
Equity in earnings of SLC Pipeline		1,025		1,025
Interest income (expense)	(11,099)	(5,989)		(17,088)
Other		(7)		(7)
	27,219	(4,971)	(38,318)	(16,070)
Income before income taxes	24,137	38,458	(38,318)	24,277
State income tax		(140)		(140)
Net income	$ 24,137	$ 38,318	$ (38,318)	$ 24,137

Table of Contents

Condensed Consolidating Statement of Cash Flows

Six Months Ended June 30, 2011	Parent	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Cash flows from operating activities	$ 46,241	$ 48	$	$ 46,289
Cash flows from investing activities				
Additions to properties and equipment		(22,900)		(22,900)
Cash flows from financing activities				
Net borrowings under credit agreement		27,000		27,000
Distributions to HEP unitholders	(44,862)			(44,862)
Purchase of units for restricted grants	(1,379)			(1,379)
Deferred financing costs		(3,149)		(3,149)
	(46,241)	23,851		(22,390)
Cash and cash equivalents				
Increase for the period		999		999
Beginning of period	2	401		403
End of period	$ 2	$ 1,400	$	$ 1,402

Condensed Consolidating Statement of Cash Flows

Six Months Ended June 30, 2010	Parent	Guarantor Subsidiaries	Eliminations	Consolidated
		(in thousands)		
Cash flows from operating activities	$ (103,599)	$ 148,785	$	$ 45,186
Cash flows from investing activities				
Additions to properties and equipment		(4,487)		(4,487)
Acquisition of assets from HFC		(39,040)		(39,040)
		(43,527)		(43,527)
Cash flows from financing activities				
Net repayments under credit agreement		(51,000)		(51,000)
Net proceeds from issuance of senior notes	147,540			147,540
Distributions to HEP unitholders	(41,312)			(41,312)
Purchase price in excess of transferred basis in assets acquired from HFC		(53,960)		(53,960)
Purchase of units for restricted grants	(2,276)			(2,276)
Deferred financing costs	(353)			(353)
	103,599	(104,960)		(1,361)

Cash and cash equivalents								
Increase for the period				298				298
Beginning of period		2		2,506				2,508
End of period	$	2	$	2,804	$		$	2,806

Table of Contents

HOLLY ENERGY PARTNERS, L.P.

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

This Item 2, including but not limited to the sections on Results of Operations and Liquidity and Capital Resources, contains forward-looking statements. See Forward-Looking Statements at the beginning of Part I of this Quarterly Report on Form 10-Q. In this document, the words we, our, ours and us refer to Holly Energy Partners, L.P. (HEP) and its consolidated subsidiaries or to HEP or an individual subsidiary and not to an other person.

OVERVIEW

HEP is a Delaware limited partnership. We own and operate petroleum product and crude oil pipeline and terminal, tankage and loading rack facilities that support the refining and marketing operations of HollyFrontier Corporation (formerly known as Holly Corporation) (HFC) in west Texas, New Mexico, Utah, Oklahoma, Idaho and Arizona. HFC and its subsidiaries currently own a 34% interest in us including the 2% general partnership interest. HFC changed its name in connection with the consummation of its merger of equals with Frontier Oil Corporation effective July 1, 2011. All previous references to Holly within this document have been replaced with HFC.

We also own and operate refined product pipelines and terminals, located primarily in Texas, that service Alon s (Alon) Big Spring refinery in Big Spring, Texas. Additionally, we own a 25% joint venture interest in the SLC Pipeline (the SLC Pipeline), a 95-mile intrastate crude oil pipeline system that serves refineries in the Salt Lake City area.

We generate revenues by charging tariffs for transporting petroleum products and crude oil through our pipelines, by charging fees for terminalling refined products and other hydrocarbons and storing and providing other services at our storage tanks and terminals. We do not take ownership of products that we transport, terminal or store, and therefore, we are not directly exposed to changes in commodity prices.

2010 Acquisitions

Tulsa East / Lovington Storage Asset Transaction

On March 31, 2010, we acquired from HFC certain storage assets for $93 million, consisting of hydrocarbon storage tanks having approximately 2 million barrels of storage capacity, a rail loading rack and a truck unloading rack located at HFC s Tulsa refinery east facility and an asphalt loading rack facility located at HFC s Navajo refinery facility in Lovington, New Mexico.

Agreements with HFC and Alon

We serve HFC s refineries in New Mexico, Utah and Oklahoma under the following long-term pipeline and terminal, tankage and throughput agreements:

- HFC PTA (pipelines and terminals throughput agreement expiring in 2019 that relates to assets contributed to us by HFC upon our initial public offering in 2004);
- HFC IPA (intermediate pipelines throughput agreement expiring in 2024 that relates to assets acquired from HFC in 2005 and 2009);
- HFC CPTA (crude pipelines and tankage throughput agreement expiring in 2023 that relates to assets acquired from HFC in 2008);
- HFC PTTA (pipeline, tankage and loading rack throughput agreement expiring in 2024 that relates to the Tulsa east facilities acquired from Sinclair in 2009 and from HFC in March 2010);

HFC RPA (pipeline throughput agreement expiring in 2024 that relates to the Roadrunner Pipeline acquired from HFC in 2009);

HFC ETA (equipment and throughput agreement expiring in 2024 that relates to the Tulsa west facilities acquired from HFC in 2009);

Table of Contents

HFC NPA (natural gas pipeline throughput agreement expiring in 2024); and

HFC ATA (asphalt loading rack throughput agreement expiring in 2025 that relates to the Lovington rack facility acquired from HFC in March 2010).

Under these agreements, HFC agreed to transport, store and throughput volumes of refined product and crude oil on our pipelines and terminal, tankage and loading rack facilities that result in minimum annual payments to us. These minimum annual payments or revenues are subject to annual tariff rate adjustments on July 1, based on the Producer Price Index (PPI) or Federal Energy Regulatory Commission (FERC) index. As of July 1, 2011, these agreements with HFC will result in minimum annualized payments to us of $140 million.

We also have a pipelines and terminals agreement with Alon expiring in 2020 under which Alon has agreed to transport on our pipelines and throughput through our terminals volumes of refined products that result in a minimum level of annual revenue that is also subject to annual tariff rate adjustments.

We have a capacity lease agreement with Alon under which we lease Alon space on our Orla to El Paso pipeline for the shipment of up to 17,500 barrels of refined product per day. The terms under this agreement expire beginning in 2012 through 2018.

As of July 1, 2011, contractual minimums under our long-term service agreements are as follows:

Agreement	Minimum Annualized Commitment (In millions)	Year of Maturity	Contract Type
HFC PTA	$ 45.6	2019	Minimum revenue commitment
HFC IPA	21.6	2024	Minimum revenue commitment
HFC CPTA	29.6	2023	Minimum revenue commitment
HFC PTTA	29.8	2024	Minimum revenue commitment
HFC RPA	9.5	2024	Minimum revenue commitment
HFC ETA	2.8	2024	Minimum revenue commitment
HFC ATA	0.5	2025	Minimum revenue commitment
HFC NPA	0.6	2024	Minimum revenue commitment
Alon PTA	23.4	2020	Minimum volume commitment
Alon capacity lease	6.6	Various	Capacity lease
Total	$ 170.0		

A significant reduction in revenues under these agreements would have a material adverse effect on our results of operations.

Under certain provisions of an omnibus agreement (Omnibus Agreement) that we have with HFC, we pay HFC an annual administrative fee, currently $2.3 million, for the provision by HFC or its affiliates of various general and administrative services to us. This fee does not include the salaries of pipeline and terminal personnel or the cost of their employee benefits, which are separately charged to us by HFC. We also reimburse HFC and its affiliates for direct expenses they incur on our behalf.

Table of Contents

RESULTS OF OPERATIONS (Unaudited)

Income, Distributable Cash Flow and Volumes

The following tables present income, distributable cash flow and volume information for the three and the six months ended June 30, 2011 and 2010.

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Change from 2010
	(In thousands, except per unit data)		
Revenues			
Pipelines:			
Affiliates refined product pipelines	$ 11,689	$ 12,067	$ (378)
Affiliates intermediate pipelines	5,069	4,964	105
Affiliates crude pipelines	9,624	9,728	(104)
	26,382	26,759	(377)
Third parties refined product pipelines	11,906	6,455	5,451
	38,288	33,214	5,074
Terminals and loading racks:			
Affiliates	10,757	10,320	437
Third parties	1,895	1,949	(54)
	12,652	12,269	383
Total revenues	50,940	45,483	5,457
Operating costs and expenses			
Operations	14,366	13,495	871
Depreciation and amortization	7,713	7,591	122
General and administrative	1,573	1,913	(340)
	23,652	22,999	653
Operating income	27,288	22,484	4,804
Equity in earnings of SLC Pipeline	467	544	(77)
Interest income		2	(2)
Interest expense, including amortization	(8,724)	(9,549)	825
	(8,257)	(9,003)	746
Income before income taxes	19,031	13,481	5,550
State income tax	(18)	(46)	28
Net income	19,013	13,435	5,578
Less general partner interest in net income, including incentive distributions [(1)]	3,847	2,909	938

Limited partners interest in net income	$ 15,166	$ 10,526	$ 4,640
Limited partners earnings per unit basic and diluted [1]	$ 0.69	$ 0.48	$ 0.21
Weighted average limited partners units outstanding	22,079	22,079	
EBITDA [2]	$ 35,468	$ 30,619	$ 4,849
Distributable cash flow [3]	$ 21,421	$ 22,673	$ (1,252)
Volumes (bpd)			
Pipelines:			
Affiliates refined product pipelines	90,984	98,464	(7,480)
Affiliates intermediate pipelines	84,201	86,140	(1,939)
Affiliates crude pipelines	160,648	141,263	19,385
	335,833	325,867	9,966
Third parties refined product pipelines	51,627	34,844	16,783
	387,460	360,711	26,749
Terminals and loading racks:			
Affiliates	182,394	186,515	(4,121)
Third parties	42,694	37,902	4,792
	225,088	224,417	671
Total for pipelines and terminal assets (bpd)	612,548	585,128	27,420

- 25 -

Table of Contents

	Six Months Ended June 30, 2011	2010	Change from 2010
	(In thousands, except per unit data)		
Revenues			
Pipelines:			
Affiliates refined product pipelines	$ 21,547	$ 23,547	$ (2,000)
Affiliates intermediate pipelines	9,702	10,756	(1,054)
Affiliates crude pipelines	18,945	19,133	(188)
	50,194	53,436	(3,242)
Third parties refined product pipelines	21,061	11,859	9,202
	71,255	65,295	5,960
Terminals and loading racks:			
Affiliates	21,052	17,240	3,812
Third parties	3,650	3,644	6
	24,702	20,884	3,818
Total revenues	95,957	86,179	9,778
Operating costs and expenses			
Operations	27,162	26,555	607
Depreciation and amortization	15,353	14,801	552
General and administrative	2,936	4,476	(1,540)
	45,451	45,832	(381)
Operating income	50,506	40,347	10,159
Equity in earnings of SLC Pipeline	1,207	1,025	182
Interest income		5	(5)
Interest expense, including amortization	(17,273)	(17,093)	(180)
Other	(12)	(7)	(5)
	(16,078)	(16,070)	(8)
Income before income taxes	34,428	24,277	10,151
State income tax	(246)	(140)	(106)
Net income	34,182	24,137	10,045
Less general partner interest in net income, including incentive distributions [1]	7,409	5,555	1,854
Limited partners interest in net income	$ 26,773	$ 18,582	$ 8,191
Limited partners earnings per unit basic and diluted [1]	$ 1.21	$ 0.84	$ 0.37
Weighted average limited partners units outstanding	22,079	22,079	
EBITDA [2]	$ 67,054	$ 56,166	$ 10,888

Distributable cash flow [3]	$ 42,193	$ 42,831	$ (638)
Volumes (bpd)			
Pipelines:			
Affiliates refined product pipelines	84,139	95,937	(11,798)
Affiliates intermediate pipelines	76,452	82,649	(6,197)
Affiliates crude pipelines	148,520	138,094	10,426
	309,111	316,680	(7,569)
Third parties refined product pipelines	50,086	32,850	17,236
	359,197	349,530	9,667
Terminals and loading racks:			
Affiliates	170,230	175,218	(4,988)
Third parties	41,532	36,381	5,151
	211,762	211,599	163
Total for pipelines and terminal assets (bpd)	570,959	561,129	9,830

(1) Net income is allocated between limited partners and the general partner interest in accordance with the provisions of the partnership agreement. Net income allocated to the general partner includes incentive distributions declared subsequent to quarter end. Net income attributable to the limited partners is divided by the weighted average limited partner units outstanding in computing the limited partners per unit interest in net income.

Table of Contents

(2) EBITDA is calculated as net income plus (i) interest expense, net of interest income, (ii) state income tax and (iii) depreciation and amortization. EBITDA is not a calculation based upon U.S. generally accepted accounting principles (GAAP). 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 also is used by our management for internal analysis and as a basis for compliance with financial covenants.

Set forth below is our calculation of EBITDA.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In thousands)			
Net income	$ 19,013	$ 13,435	$ 34,182	$ 24,137
Add (subtract):				
Interest expense	8,419	8,209	16,678	14,095
Amortization of discount and deferred debt issuance costs	305	264	595	458
Increase in interest expense change in fair value of interest rate swaps and swap settlement costs		1,076		2,540
Interest income		(2)		(5)
State income tax	18	46	246	140
Depreciation and amortization	7,713	7,591	15,353	14,801
EBITDA	$ 35,468	$ 30,619	$ 67,054	$ 56,166

(3) Distributable cash flow is not a calculation based upon GAAP. However, the amounts included in the calculation are derived from amounts separately presented in our consolidated financial statements, with the exception of equity in excess cash flows over earnings of SLC Pipeline, and maintenance capital expenditures. Distributable cash flow should not be considered in isolation or 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. Distributable cash flow is not necessarily comparable to similarly titled measures of other companies. Distributable cash flow is presented here because it is a widely accepted financial indicator used by investors to compare partnership performance. It is also used by management for internal analysis and for our performance units. We believe that this measure provides investors an enhanced perspective of the operating performance of our assets and the cash our business is generating.

Table of Contents

Set forth below is our calculation of distributable cash flow.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In thousands)			
Net income	$ 19,013	$ 13,435	$ 34,182	$ 24,137
Add (subtract):				
Depreciation and amortization	7,713	7,591	15,353	14,801
Amortization of discount and deferred debt issuance costs	305	264	595	458
Increase in interest expense change in fair value of interest rate swaps and swap settlement costs		1,076		2,540
Equity in excess cash flows over earnings of SLC Pipeline	308	174	314	352
Increase (decrease) in deferred revenue	(4,014)	1,414	(5,118)	2,521
Maintenance capital expenditures*	(1,904)	(1,281)	(3,133)	(1,978)
Distributable cash flow	$ 21,421	$ 22,673	$ 42,193	$ 42,831

* Maintenance capital expenditures are capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of our assets and to extend their useful lives. Maintenance capital expenditures include expenditures required to maintain equipment reliability, tankage and pipeline integrity, safety and to address environmental regulations.

Balance Sheet Data	June 30, 2011	December 31, 2010
	(In thousands)	
Cash and cash equivalents	$ 1,402	$ 403
Working capital deficit	$ (2,026)	$ (7,758)
Total assets	$ 651,151	$ 643,273
Long-term debt	$ 518,818	$ 491,648
Partners equity(4)	$ 99,947	$ 109,372

(4) As a master limited partnership, we distribute our available cash, which historically has exceeded our net income because depreciation and amortization expense represents a non-cash charge against income. The result is a decline in partners equity since our regular quarterly distributions have exceeded our quarterly net income. Additionally, if the assets contributed and acquired from HFC had occurred while we were not a consolidated variable interest entity of HFC, our acquisition cost in excess of HFC s historical basis in the transferred assets of $218 million would have been recorded in our financial statements as increases to our properties and equipment and intangible assets instead of decreases to our partners equity.

Table of Contents

Results of Operations Three Months Ended June 30, 2011 Compared with Three Months Ended June 30, 2010

Summary

Net income for the three months ended June 30, 2011 was $19 million, a $5.6 million increase compared to the three months ended June 30, 2010. This increase in overall earnings is due principally to an increase in deferred revenue realized and increased third-party refined product pipeline shipments.

Revenues for the three months ended June 30, 2011 include the recognition of $5.5 million of prior shortfalls billed to shippers in 2010 as they did not meet their minimum volume commitments within the contractual make-up period. This includes the recognition of $2.4 million of shortfalls billed in the third and fourth quarters of 2010 as a result of an amendment to the Alon PTA in June 2011 that limits the carryover term of shortfall credits to the calendar year in which the shortfalls occurred. Revenues of $1.5 million relating to deficiency payments associated with certain guaranteed shipping contracts were deferred during the three months ended June 30, 2011. Such deferred revenue will be recognized in earnings either as payment for shipments in excess of guaranteed levels, or when shipping rights expire unused.

Revenues

Total revenues for the three months ended June 30, 2011 were $50.9 million, a $5.5 million increase compared to the three months ended June 30, 2010. This is due principally to a $3.8 million increase in previously deferred revenue realized. Overall pipeline shipments were up 7% from the second quarter of 2010, due mainly to an increase in third-party refined product pipeline shipments.

Revenues from our refined product pipelines were $23.6 million, an increase of $5.1 million compared to the three months ended June 30, 2010. This increase is due principally to a $3.6 million increase in previously deferred revenue realized. Volumes shipped on our refined product pipelines averaged 142.6 thousand barrels per day (mbpd) compared to 133.3 mbpd for the same period last year.

Revenues from our intermediate pipelines were $5.1 million, an increase of $0.1 million compared to the three months ended June 30, 2010. This reflects a $0.2 million increase in previously deferred revenue realized, partially offset by a decrease in intermediate pipeline shipments. Volumes shipped on our intermediate pipelines averaged 84.2 mbpd compared to 86.1 mbpd for the same period last year.

Revenues from our crude pipelines were $9.6 million, a decrease of $0.1 million compared to the three months ended June 30, 2010. Volumes shipped on our crude pipelines averaged 160.6 mbpd compared to 141.3 mbpd for the same period last year. Although shipments were up, we did not realize higher revenues in the current year due to the receipt of higher minimum revenue commitment fees from HFC in 2010.

Revenues from terminal, tankage and loading rack fees were $12.7 million, an increase of $0.4 million compared to the three months ended June 30, 2010. Refined products terminalled in our facilities increased to an average of 225.1 mbpd compared to 224.4 mbpd for the same period last year.

Operations Expense

Operations expense for the three months ended June 30, 2011 increased by $0.9 million compared to the three months ended June 30, 2010. This increase is due principally to increased maintenance costs during the current year second quarter.

Depreciation and Amortization

Depreciation and amortization for the three months ended June 30, 2011 increased by $0.1 million compared to the three months ended June 30, 2010.

Table of Contents

General and Administrative

General and administrative costs for the three months ended June 30, 2011 decreased by $0.3 million compared to the three months ended June 30, 2010 due to lower professional fees during the current year.

Equity in Earnings of SLC Pipeline

Our equity in earnings of the SLC Pipeline was $0.5 million for the three months ended June 30, 2011 and 2010.

Interest Expense

Interest expense for the three months ended June 30, 2011 totaled $8.7 million, a decrease of $0.8 million compared to the three months ended June 30, 2010. Interest costs for the three months ended June 30, 2010 include $1.1 million in costs attributable to the partial settlement of an interest rate swap. This was partially offset by interest on increased credit agreement borrowings during the current year. Our aggregate effective interest rate was 6.7% for the three months ended June 30, 2011 compared to 7.7% for the same period of 2010.

State Income Tax

We recorded state income taxes of $18,000 and $46,000 for the three months ended June 30, 2011 and 2010, respectively, which are solely attributable to the Texas margin tax.

Results of Operations Six Months Ended June 30, 2011 Compared with Six Months Ended June 30, 2010

Summary

Net income for the six months ended June 30, 2011 was $34.2 million, a $10 million increase compared to the six months ended June 30, 2010. This increase in overall earnings is due principally to an overall increase in pipeline shipments, earnings attributable to our March 2010 asset acquisitions and an increase in previously deferred revenue realized.

Revenues for the six months ended June 30, 2011 include the recognition of $9.1 million of prior shortfalls billed to shippers in 2010. Revenues of $3.9 million relating to deficiency payments associated with certain guaranteed shipping contracts were deferred during the six months ended June 30, 2011. Such deferred revenue will be recognized in earnings either as payment for shipments in excess of guaranteed levels, or when shipping rights expire unused.

Revenues

Total revenues for the six months ended June 30, 2011 were $96 million, a $9.8 million increase compared to the six months ended June 30, 2010. This is due principally to increased pipeline shipments, revenues attributable to our March 2010 asset acquisitions and a $4.9 million increase in previously deferred revenue realized. Overall pipeline shipments were up 3% from the six months ended June 30, 2010, due to an increase in third-party refined product pipeline shipments that was partially offset by decreased affiliate pipeline shipments.

Related-party pipeline and throughput volumes were down during the current year-to-date period as a result of downtime at HFC s Navajo refinery following a plant-wide power outage in late January 2011 and the subsequent delay in restoring production to planned levels.

Revenues from our refined product pipelines were $42.6 million, an increase of $7.2 million compared to the six months ended June 30, 2010. This is due to a $5.3 million increase in previously deferred revenue realized and an increase in third-party refined product pipeline shipments. Volumes shipped on our refined product pipelines averaged 134.2 mbpd compared to 128.8 mbpd for the same period last year.

Table of Contents

Revenues from our intermediate pipelines were $9.7 million, a decrease of $1.1 million compared to the six months ended June 30, 2010. This reflects a $0.4 million decrease in previously deferred revenue realized and a decrease in intermediate pipeline shipments. Shipments on our intermediate pipelines decreased to an average of 76.5 mbpd compared to 82.6 mbpd for the same period last year.

Revenues from our crude pipelines were $18.9 million, a decrease of $0.2 million compared to the six months ended June 30, 2010. Volumes on our crude pipelines averaged 148.5 mbpd compared to 138.1 mbpd for the same period last year. Although shipments were up, we did not realize higher revenues in the current year due to the receipt of higher minimum revenue commitment fees from HFC in 2010.

Revenues from terminal, tankage and loading rack fees were $24.7 million, an increase of $3.8 million compared to the six months ended June 30, 2010. This increase is due primarily to revenues attributable to our Tulsa storage and rack facilities acquired from HFC in March 2010. Refined products terminalled in our facilities increased to an average of 211.8 mbpd compared to 211.6 mbpd for the same period last year.

Operations Expense

Operations expense for the six months ended June 30, 2011 increased by $0.6 million compared to the six months ended June 30, 2010. This increase is due principally to increased maintenance costs during the current year-to-date period.

Depreciation and Amortization

Depreciation and amortization for the six months ended June 30, 2011 increased by $0.6 million compared to the six months ended June 30, 2010. This was due to increased depreciation attributable to our March 2010 asset acquisitions from HFC and capital projects.

General and Administrative

General and administrative costs for the six months ended June 30, 2011 decreased by $1.5 million compared to the six months ended June 30, 2010, which included higher professional fees and costs as a result of our March 2010 asset acquisitions from HFC.

Equity in Earnings of SLC Pipeline

Our equity in earnings of the SLC Pipeline was $1.2 million and $1 million for the six months ended June 30, 2011 and 2010, respectively.

Interest Expense

Interest expense for the six months ended June 30, 2011 totaled $17.3 million, an increase of $0.2 million compared to the six months ended June 30, 2010. This increase reflects interest on increased debt levels during the current year, partially offset by prior year costs of $1.1 million that relate to the partial settlement of an interest rate swap. Excluding the effects of fair value adjustments to this swap in 2010, our aggregate effective interest rate was 6.7% for the six months ended June 30, 2011 compared to 6.8% for 2010.

State Income Tax

We recorded state income taxes of $246,000 and $140,000 for the six months ended June 30, 2011 and 2010, respectively, which are solely attributable to the Texas margin tax.

Table of Contents

LIQUIDITY AND CAPITAL RESOURCES

Overview

During the six months ended June 30, 2011, we received advances totaling $64 million and repaid $37 million, resulting in net borrowings of $27 million under our $275 million senior secured revolving credit facility (the Credit Agreement) and an outstanding balance of $186 million at June 30, 2011.

The Credit Agreement is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. It is also available to fund letters of credit up to a $50 million sub-limit and to fund distributions to unitholders up to a $30 million sub-limit.

In March 2010, we issued $150 million in aggregate principal amount of 8.25% senior notes maturing March 15, 2018 (the 8.25% Senior Notes). A portion of the $147.5 million in net proceeds received was used to fund our $93 million purchase of the Tulsa and Lovington storage assets from HFC on March 31, 2010. Additionally, we used a portion to repay $42 million in outstanding Credit Agreement borrowings, with the remaining proceeds available for general partnership purposes, including working capital and capital expenditures. In addition, we have outstanding $185 million in aggregate principal amount of 6.25% senior notes maturing March 1, 2015 (the 6.25% Senior Notes) that are registered with the SEC.

Under our registration statement filed with the SEC using a shelf registration process, we currently have the ability to raise $860 million through security offerings, through one or more prospectus supplements that would describe, among other things, the specific amounts, prices and terms of any securities offered and how the proceeds would be used. Any proceeds from the sale of securities would be used for general business purposes, which may include, among other things, funding acquisitions of assets or businesses, working capital, capital expenditures, investments in subsidiaries, the retirement of existing debt and/or the repurchase of common units or other securities.

We believe our current cash balances, future internally generated funds and funds available under the Credit Agreement will provide sufficient resources to meet our working capital liquidity needs for the foreseeable future.

In February and May 2011 we paid regular quarterly cash distributions of $0.845 and $0.855, respectively, on all units in an aggregate amount of $44.9 million. Included in these distributions were $6.4 million of incentive distribution payments to the general partner.

Cash and cash equivalents increased by $1 million during the six months ended June 30, 2011. The cash flows provided by operating activities of $46.3 million exceeded the combined cash flows used for investing and financing activities of $22.9 million and $22.4 million, respectively. Working capital increased by $5.7 million to $(2.0) million during the six months ended June 30, 2011.

Cash Flows - Operating Activities

Cash flows from operating activities increased by $1.1 million from $45.2 million for the six months ended June 30, 2010 to $46.3 million for the six months ended June 30, 2011. This increase is due principally to $3.1 million in additional cash collections from our customers combined with a decrease in payments related to operating expenses. These factors were partially offset by increased interest payments.

Our major shippers are obligated to make deficiency payments to us if they do not meet their minimum volume shipping obligations. Under certain agreements with these shippers, they have the right to recapture these amounts if future volumes exceed minimum levels. We billed $6.6 million during the six months ended June 30, 2010 related to shortfalls that subsequently expired without recapture and were recognized as revenue during the six months ended June 30, 2011. We recognized an additional $2.4 million related to shortfalls billed in the third and fourth quarters of 2010 as a result of an amendment to the Alon PTA in June 2011 that limits the carryover term of credits attributable to such shortfall billings to the calendar year end in which the shortfalls occurred. Another $1.5 million is included in our accounts receivable at June 30, 2011 related to shortfalls that occurred during the second quarter of 2011.

Cash Flows - Investing Activities

Cash flows used for investing activities decreased by $20.6 million from $43.5 million for the six months ended June 30, 2010 to $22.9 million for the six months ended June 30, 2011. During the six months ended June 30, 2011 and 2010, we invested $22.9 million and $4.5 million in additions to properties and equipment, respectively. Additionally in March 2010, we acquired storage assets from HFC for $39 million.

Cash Flows - Financing Activities

Cash flows used for financing activities were $22.4 million compared to $1.4 million for the six months ended June 30, 2010, an increase of $21 million. During the six months ended June 30, 2011, we received $64 million and repaid $37 million in advances under the Credit Agreement, we paid $44.9 million in regular quarterly cash distributions to our general and limited partners, paid $3.1 million in financing costs to amend our previous credit agreement and paid $1.4 million for the purchase of common units for recipients of our incentive grants. During the six months ended June 30, 2010, we received $39 million and repaid $90 million in advances under the Credit Agreement. Additionally, we received $147.5 million in net proceeds and incurred $0.4 million in financing costs upon the issuance of the 8.25% Senior Notes. For the six months ended June 30, 2010, we paid $41.3 million in regular quarterly cash distributions to our general and limited partners, paid $54 million in excess of HFC s transferred basis in the storage assets acquired in March 2010 and paid $2.3 million for the purchase of common units for recipients of our incentive grants.

Capital Requirements

Our pipeline and terminalling operations are capital intensive, requiring investments to maintain, expand, upgrade or enhance existing operations and to meet environmental and operational regulations. Our capital requirements consist of maintenance capital expenditures and expansion capital expenditures. Repair and maintenance expenses associated with existing assets that are minor in nature and do not extend the useful life of existing assets are charged to operating expenses as incurred.

Each year the HLS board of directors approves our annual capital budget, which specifies capital projects that our management is authorized to undertake. Additionally, at times when conditions warrant or as new opportunities arise, special projects may be approved. The funds allocated for a particular capital project may be expended over a period in excess of a year, depending on the time required to complete the project. Therefore, our planned capital expenditures for a given year consist of expenditures approved for capital projects included in the current year s capital budget as well as, in certain cases, expenditures approved for capital projects in capital budgets for prior years. The 2011 capital budget is comprised of $5.8 million for maintenance capital expenditures and $20.1 million for expansion capital expenditures.

We are currently constructing five interconnecting pipelines between HFC s Tulsa east and west refining facilities. The project is expected to cost approximately $35 million with completion in the late summer of 2011. We are finalizing terms under a long-term agreement with HFC to transfer intermediate products via these pipelines that will commence upon completion of the project. In the event that we are unable to obtain such an agreement, HFC will reimburse us for the cost of the pipelines.

Additionally, we have two expansion projects to provide 60,000 bpd of additional crude pipeline take-away capacity resulting from increased Delaware Basin drilling activity in southeast New Mexico.

The first project will increase one of our existing crude oil trunk lines from 35,000 bpd to 60,000 bpd. This 35-mile pipeline transports crude oil from our gathering system in southeast New Mexico to HFC s New Mexico refining facilities. The scope of the project includes the replacement of 5 miles of existing pipe with larger diameter pipe and the addition of a higher horsepower pump. Work will commence shortly and is expected to be completed during the first half of 2012.

The second project will consist of the reactivation and conversion to crude oil service a 70-mile, 8-inch petroleum products pipeline owned by us. Once in service, this pipeline would be capable of transporting up to 35,000 bpd of crude oil from rapidly developing Delaware Basin production in the Carlsbad, New Mexico area to either a third party common carrier pipeline station for transport to major crude oil markets or to HFC s New Mexico refining facilities. The scope of this project is in the process of being finalized. It is anticipated that this project, subject to receipt of acceptable shipper support and board approval, could also be completed during the first half of 2012.

We have an option agreement with HFC, granting us an option to purchase HFC s 75% equity interest in UNEV Pipeline, LLC (UNEV Pipeline), a joint venture pipeline currently under construction that will be capable of transporting refined petroleum products from Salt Lake City, Utah to Las Vegas, Nevada. Under this agreement, we have an option to purchase HFC s equity interest in the UNEV Pipeline, effective for a 180-day period commencing when the UNEV Pipeline becomes operational, at a purchase price equal to HFC s investment in the joint venture pipeline, plus interest at 7% per annum. The initial capacity of the pipeline will be 62,000 bpd, with the capacity for further expansion to 120,000 bpd. The current total construction cost of the pipeline project including terminals is expected to be approximately $385 million. This includes the construction of ethanol blending and storage facilities at the Cedar City terminal. HFC s share of this estimated cost is $289 million and is exclusive of the 7% per annum interest cost under our option to purchase HFC s 75% interest in the UNEV Pipeline. The pipeline is in the final construction phase and is expected to be mechanically complete later this year.

We expect that our currently planned sustaining and maintenance capital expenditures as well as expenditures for acquisitions and capital development projects such as the UNEV Pipeline described above, will be funded with existing cash generated by operations, the sale of additional limited partner common units, the issuance of debt securities and advances under our Credit Agreement, or a combination thereof. With volatility and uncertainty at times in the credit and equity markets, there may be limits on our ability to issue new debt or equity financing. Additionally, due to pricing movements in the debt and equity markets, we may not be able to issue new debt and equity securities at acceptable pricing. Without additional capital beyond amounts available under the Credit Agreement, our ability to fund some of these capital projects may be limited, especially the UNEV Pipeline. We are not obligated to purchase the UNEV Pipeline nor are we subject to any fees or penalties if HLS board of directors decides not to proceed with this opportunity.

Credit Agreement

We have a $275 million Credit Agreement that is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. It is also available to fund letters of credit up to a $50 million sub-limit and to fund distributions to unitholders up to a $30 million sub-limit. In February 2011, we amended our previous credit agreement (expiring in August 2011), extending the expiration date and slightly reducing the size of the credit facility from $300 million to $275 million. The size was reduced based on management s review of past and forecasted utilization of the facility. The Credit Agreement expires in February 2016; however, in the event that the 6.25% Senior Notes are not repurchased, refinanced, extended or repaid prior to September 1, 2014, the Credit Agreement shall expire on that date.

Our obligations under the Credit Agreement are collateralized by substantially all of our assets. Indebtedness under the Credit Agreement is recourse to HEP Logistics Holdings, L.P., our general partner, and guaranteed by our material, wholly-owned subsidiaries. Any recourse to HEP Logistics Holdings, L.P. would be limited to the extent of its assets, which other than its investment in us, are not significant.

We may prepay all loans at any time without penalty, except for payment of certain breakage and related costs.

Indebtedness under the Credit Agreement bears interest, at our option, at either (a) the reference rate as announced by the administrative agent plus an applicable margin (ranging from 1.00% to 2.00%) or (b) at a rate equal to the London Interbank Offered Rate (LIBOR) plus an applicable margin (ranging from 2.00% to 3.00%). In each case, the applicable margin is based upon the ratio of our funded debt (as defined in the Credit Agreement) to EBITDA (earnings before interest, taxes, depreciation and amortization, as defined in the Credit Agreement). We incur a commitment fee on the unused portion of the Credit Agreement at an annual rate ranging from 0.375% to 0.50% based upon the ratio of our funded debt to EBITDA for the four most recently completed fiscal quarters.

Table of Contents

The Credit Agreement imposes certain requirements on us including: a prohibition against distribution to unitholders if, before or after the distribution, a potential default or an event of default as defined in the agreement would occur; limitations on our ability to incur debt, make loans, acquire other companies, change the nature of our business, enter a merger or consolidation, or sell assets; and covenants that require maintenance of a specified EBITDA to interest expense ratio, total debt to EBITDA ratio and senior debt to EBITDA ratio. If an event of default exists under the agreement, the lenders will be able to accelerate the maturity of the debt and exercise other rights and remedies.

Senior Notes

The 6.25% Senior Notes and 8.25% Senior Notes (collectively, the Senior Notes) are unsecured and impose certain restrictive covenants which we are subject to and currently in compliance with, including limitations on our ability to incur additional indebtedness, make investments, sell assets, incur certain liens, pay distributions, enter into transactions with affiliates, and enter into mergers. At any time when the Senior Notes are rated investment grade by both Moody s and Standard & Poor s and no default or event of default exists, we will not be subject to many of the foregoing covenants. Additionally, we have certain redemption rights under the Senior Notes.

Indebtedness under the Senior Notes is recourse to HEP Logistics Holdings, L.P., our general partner, and guaranteed by our wholly-owned subsidiaries. However, any recourse to HEP Logistics Holdings, L.P. would be limited to the extent of its assets, which other than its investment in us, are not significant.

The carrying amounts of our long-term debt are as follows:

	June 30, 2011	December 31, 2010
	(In thousands)	
Credit Agreement	$ 186,000	$ 159,000
6.25% Senior Notes		
Principal	185,000	185,000
Unamortized discount	(1,394)	(1,584)
Unamortized premium dedesignated fair value hedge	1,271	1,444
	184,877	184,860
8.25% Senior Notes		
Principal	150,000	150,000
Unamortized discount	(2,059)	(2,212)
	147,941	147,788
Total long-term debt	$ 518,818	$ 491,648

See Risk Management for a discussion of our interest rate swap.

Contractual Obligations

During the six months ended June 30, 2011, we had net borrowings of $27 million resulting in $186 million of borrowings outstanding under the Credit Agreement at June 30, 2011.

There were no other significant changes to our long-term contractual obligations during this period.

Impact of Inflation

Inflation in the United States has been relatively moderate in recent years and did not have a material impact on our results of operations for the six months ended June 30, 2011 and 2010. Historically, the PPI has increased an average of 3% annually over the past 5 calendar years. However, the June 30, 2011 PPI increased at a rate of 7% on a year-over-year basis.

The substantial majority of our revenues are generated under long-term contracts that provide for increases in our rates and minimum revenue guarantees annually for increases in the PPI. Certain of these contracts have provisions that limit the level of annual PPI percentage rate increases. Although the recent PPI increase may not be indicative of additional increases to be realized in the future, a significant and prolonged period of inflation could adversely affect our cash flows and results of operations if costs increase at a rate greater than the fees we charge our shippers.

Environmental Matters

Our operation of pipelines, terminals, and associated facilities in connection with the transportation and storage of refined products and crude oil is subject to stringent and complex federal, state, and local laws and regulations governing the discharge of materials into the environment, or otherwise relating to the protection of the environment. As with the industry generally, compliance with existing and anticipated laws and regulations increases our overall cost of business, including our capital costs to construct, maintain, and upgrade equipment and facilities. While these laws and regulations affect our maintenance capital expenditures and net income, we believe that they do not affect our competitive position in that the operations of our competitors are similarly affected. We believe that our operations are in substantial compliance with applicable environmental laws and regulations. However, these laws and regulations, and the interpretation or enforcement thereof, are subject to frequent change by regulatory authorities, and we are unable to predict the ongoing cost to us of complying with these laws and regulations or the future impact of these laws and regulations on our operations. Violation of environmental laws, regulations, and permits can result in the imposition of significant administrative, civil and criminal penalties, injunctions, and construction bans or delays. A discharge of hydrocarbons or hazardous substances into the environment could, to the extent the event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and claims made by employees, neighboring landowners and other third parties for personal injury and property damage.

Under the Omnibus Agreement, HFC agreed to indemnify us up to certain aggregate amounts for any environmental noncompliance and remediation liabilities associated with assets transferred to us and occurring or existing prior to the date of such transfers. The transfers that are covered by the agreement include the refined product pipelines, terminals and tanks transferred by HFC s subsidiaries in connection with our initial public offering in July 2004, the intermediate pipelines acquired in July 2005, the crude pipelines and tankage assets acquired in 2008, and the asphalt loading rack facility acquired in March 2010. The Omnibus Agreement provides environmental indemnification of up to $15 million for the assets transferred to us, other than the crude pipelines and tankage assets, plus an additional $2.5 million for the intermediate pipelines acquired in July 2005. Except as described below, HFC s indemnification obligations described above will remain in effect for an asset for ten years following the date it is transferred to us. The Omnibus Agreement also provides an additional $7.5 million of indemnification through 2023 for environmental noncompliance and remediation liabilities specific to the crude pipelines and tankage assets. HFC s indemnification obligations described above do not apply to (i) the Tulsa west loading racks acquired in August 2009, (ii) the 16-inch intermediate pipeline acquired in June 2009, (iii) the Roadrunner Pipeline, (iv) the Beeson Pipeline, (v) the logistics and storage assets acquired from Sinclair in December 2009, or (vi) the Tulsa east storage tanks and loading racks acquired in March 2010.

Under provisions of the HFC ETA and HFC PTTA, HFC will indemnify us for environmental liabilities arising from our pre-ownership operations of the Tulsa west loading rack facilities acquired from HFC in August 2009, the Tulsa logistics and storage assets acquired from Sinclair in December 2009 and the Tulsa east storage tanks and loading racks acquired from HFC in March 2010. Additionally, HFC agreed to indemnify us for any liabilities arising from HFC s operation of the loading racks under the HFC ETA.

We have an environmental agreement with Alon with respect to pre-closing environmental costs and liabilities relating to the pipelines and terminals acquired from Alon in 2005, under which Alon will indemnify us through 2015, subject to a $100,000 deductible and a $20 million maximum liability cap.

There are environmental remediation projects that are currently in progress that relate to certain assets acquired from HFC. Certain of these projects were underway prior to our purchase and represent liabilities of HFC as the obligation for future remediation activities was retained by HFC. At June 30,

Table of Contents

2011, we have an accrual of $0.2 million that relates to environmental clean-up projects for which we have assumed liability. The remaining projects, including assessment and monitoring activities, are covered under the HFC environmental indemnification discussed above and represent liabilities of HFC.

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. We consider the following policies to be the most critical to understanding the judgments that are involved and the uncertainties that could impact our results of operations, financial condition and cash flows.

Our significant accounting policies are described in Item 7. Management s Discussion and Analysis of Financial Condition and Operations Critical Accounting Policies in our Annual Report on Form 10-K for the year ended December 31, 2010. Certain critical accounting policies that materially affect the amounts recorded in our consolidated financial statements include revenue recognition, 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 2011. We consider these policies to be the most critical to understanding the judgments that are involved and the uncertainties that could impact our results of operations, financial condition and cash flows.

RISK MANAGEMENT

We use interest rate swaps (derivative instruments) to manage our exposure to interest rate risk.

As of June 30, 2011, we have an interest rate swap that hedges our exposure to the cash flow risk caused by the effects of LIBOR changes on a $155 million Credit Agreement advance. This interest rate swap effectively converts $155 million of LIBOR based debt to fixed rate debt having an interest rate of 3.74% plus an applicable margin currently 2.50%, which equals an effective interest rate of 6.24% as of June 30, 2011. This swap contract matures in February 2013.

We have designated this interest rate swap as a cash flow hedge. Based on our assessment of effectiveness using the change in variable cash flows method, we have determined that this interest rate swap is effective in offsetting the variability in interest payments on $155 million of our variable rate debt resulting from changes in LIBOR. Under hedge accounting, we adjust our cash flow hedge on a quarterly basis to its fair value with the offsetting fair value adjustment to accumulated other comprehensive loss. Also on a quarterly basis, we measure hedge effectiveness by comparing the present value of the cumulative change in the expected future interest to be paid or received on the variable leg of our swap against the expected future interest payments on $155 million of our variable rate debt. Any ineffectiveness is reclassified from accumulated other comprehensive loss to interest expense. To date, we have had no ineffectiveness on our cash flow hedge.

Table of Contents

Additional information on our interest rate swap is as follows:

Derivative Instrument	Balance Sheet Location	Fair Value	Location of Offsetting Balance	Offsetting Amount
		(In thousands)		
June 30, 2011				
Interest rate swap designated as cash flow hedging instrument:				
Variable-to-fixed interest rate swap contract ($155 million of LIBOR based debt interest)	Other long-term liabilities	$ 8,472	Accumulated other comprehensive loss	$ 8,472
December 31, 2010				
Interest rate swap designated as cash flow hedging instrument:				
Variable-to-fixed interest rate swap contract ($155 million of LIBOR based debt interest)	Other long-term liabilities	$ 10,026	Accumulated other comprehensive loss	$ 10,026

We review publicly available information on our counterparty in order to review and monitor its financial stability and assess its ongoing ability to honor its commitments under the interest rate swap contract. This counterparty is a large financial institution. Furthermore, we have not experienced, nor do we expect to experience, any difficulty in the counterparty honoring its respective commitment.

The market risk inherent in our debt positions is the potential change arising from increases or decreases in interest rates as discussed below.

At June 30, 2011, we had an outstanding principal balance on our 6.25% Senior Notes and 8.25% Senior Notes of $185 million and $150 million, respectively. A change in interest rates would generally affect the fair value of the Senior Notes, but not our earnings or cash flows. At June 30, 2011, the fair value of our 6.25% Senior Notes and 8.25% Senior Notes were $184.1 million and $159.4 million, respectively. We estimate a hypothetical 10% change in the yield-to-maturity applicable to the 6.25% Senior Notes and 8.25% Senior Notes at June 30, 2011 would result in a change of approximately $4 million and $6 million, respectively, in the fair value of the underlying notes.

For the variable rate Credit Agreement, changes in interest rates would affect cash flows, but not the fair value. At June 30, 2011, borrowings outstanding under the Credit Agreement were $186 million. By means of our cash flow hedge, we have effectively converted the variable rate on $155 million of outstanding borrowings to a fixed rate of 6.24%.

At June 30, 2011, our cash and cash equivalents included highly liquid investments with a maturity of three months or less at the time of purchase. Due to the short-term nature of our cash and cash equivalents, a hypothetical 10% increase in interest rates would not have a material effect on the fair market value of our portfolio. Since we have the ability to liquidate this portfolio, we do not expect our operating results or cash flows to be materially affected by the effect of a sudden change in market interest rates on our investment portfolio.

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.

We have a risk management oversight committee that is made up of members from our senior management. This committee monitors our risk environment and provides direction for activities to mitigate, to an acceptable level, identified risks that may adversely affect the achievement of our goals.

Table of Contents

Item 3. Quantitative and Qualitative Disclosures About Market Risks

Market risk is the risk of loss arising from adverse changes in market rates and prices. See Risk Management under Management s Discussion and Analysis of Financial Condition and Results of Operations for a discussion of market risk exposures that we have with respect to our cash and cash equivalents and long-term debt. We utilize derivative instruments to hedge our interest rate exposure, also discussed under Risk Management.

Since we do not own products shipped on our pipelines or terminalled at our terminal facilities, we do not have market risks associated with commodity prices.

Item 4. Controls and Procedures

(a) 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 Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this quarterly report on Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information we are required to disclose in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of June 30, 2011.

(b) 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.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We are a party to various legal and regulatory proceedings, none of which we believe will have a material adverse impact on our financial condition, results of operations or cash flows.

Item 6. Exhibits

The Exhibit Index on page 42 of this Quarterly Report on Form 10-Q lists the exhibits that are filed or furnished, as applicable, as part of the Quarterly Report on Form 10-Q.

Table of Contents

HOLLY ENERGY PARTNERS, L.P.

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 ENERGY PARTNERS, L.P.
(Registrant)

By: HEP LOGISTICS HOLDINGS, L.P.

its General Partner

By: HOLLY LOGISTIC SERVICES, L.L.C.

its General Partner

Date: August 1, 2011

/s/ Douglas S. Aron
Douglas S. Aron
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

/s/ Scott C. Surplus
Scott C. Surplus
Vice President and Controller
(Principal Accounting Officer)

Exhibit Index

Exhibit Number	Description
3.1	Amendment No. 1 to the First Amended and Restated Limited Liability Company Agreement of Holly Logistic Services, L.L.C., dated April 27, 2011 (incorporated by reference to Exhibit 3.1 of Registrant s Form 8-K Current Report dated May 3, 2011, File No. 1-32225).
10.1+	First Letter Agreement with respect to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated January 25, 2005
10.2+	Second Letter Agreement with respect to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated June 29, 2007
10.3+	Third Letter Agreement with respect to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated April 1, 2011
10.4+	First Amendment of Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated September 1, 2008
10.5+	Second Amendment to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated March 1, 2011
10.6+	Third Amendment to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and ALON USA, LP, dated June 6, 2011
12.1+	Computation of Ratio of Earnings to Fixed Charges.
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.
101**	The following financial information from Holly Energy Partners, L.P. s Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Income, (iii) Consolidated Statements of Cash Flows, (iv) Consolidated Statements of Partners Equity, and (v) Notes to Consolidated Financial Statements (tagged as blocks of text).

+ Filed herewith.
++ Furnished herewith.
** Furnished electronically herewith.