DCP Midstream Partners, LP
Form 10-Q
August 11, 2006

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2006

OR

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

For the transition period from to

Commission File Number: 001-32678

DCP MIDSTREAM PARTNERS, LP

(Exact name of registrant as specified in its charter)

Delaware	**03-0567133**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
370 17th Street, Suite 2775 Denver, Colorado	**80202**
(Address of principal executive offices)	(Zip Code)

Registrant s telephone number, including area code**: 303-633-2900**

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

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

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

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

As of August 7, 2006, there were outstanding 10,357,143 common limited partner units and 7,142,857 subordinated units.

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Our reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. You can typically identify forward-looking statements by the use of forward-looking words, such as may, could, project, believe, anticipate, expect, estimate, potential, pl other similar words.

All statements that are not statements of historical facts, including statements regarding our future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements.

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in Item 1A. Risk Factors in our annual report on Form 10-K for the year ended December 31, 2005 as well as the following risks and uncertainties:

- our ability to access the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- our use of derivative financial instruments to hedge commodity and interest rate risks;
- the level of creditworthiness of counterparties to our transactions;
- the amount of collateral required to be posted from time to time in our transactions;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment or the increased regulation of the gathering and processing industry;
- the timing and extent of changes in commodity prices, interest rates and demand for our services;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain required approvals for construction or modernization of gathering and processing facilities, and the timing of production from such facilities, which are dependent on the issuance by federal, state and municipal governments, or agencies thereof, of building, environmental and other permits, the availability of specialized contractors and work force and prices of and demand for products;
- our ability to grow through acquisitions, contributions from our parent or internal growth projects;
- the extent of success in connecting natural gas supplies to gathering and processing systems; and
- general economic, market and business conditions.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

DCP MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2006	December 31, 2005
	($ in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 20.3	$ 42.2
Short-term investments	2.8	
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.1 million at both periods	30.1	24.4
Affiliates	5.5	56.5
Other	0.2	1.1
Inventories		0.1
Unrealized gains on non-trading derivative and hedging transactions	2.4	0.1
Other	0.1	0.1
Total current assets	61.4	124.5
Restricted investments	100.0	100.4
Property, plant and equipment, net	169.9	168.9
Intangible asset, net	2.1	2.1
Equity method investment	5.4	5.3
Unrealized gains on non-trading derivative and hedging transactions	5.5	5.4
Other non-current assets	0.8	0.7
Total assets	$ 345.1	$ 407.3
LIABILITIES AND PARTNERS EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 24.8	$ 42.5
Affiliates	3.4	42.0
Other	1.3	2.5
Unrealized losses on non-trading derivative and hedging transactions	3.4	2.4
Accrued interest payable	0.6	0.8
Other	6.4	3.2
Total current liabilities	39.9	93.4
Long-term debt	190.0	210.1
Unrealized losses on non-trading derivative and hedging transactions	7.8	2.5

Other long-term liabilities	0.8	0.4
Total liabilities	238.5	306.4
Commitments and contingent liabilities		
Partners equity:		
Common unitholders (10,357,143 units issued and outstanding at both periods)	219.3	215.8
Subordinated unitholders (7,142,857 convertible units issued and outstanding at both periods)	(104.3)	(109.7)
General partner interest (2% interest with 357,143 equivalent units outstanding at both periods)	(5.3)	(5.6)
Accumulated other comprehensive (loss) income	(3.1)	0.4
Total partners equity	106.6	100.9
Total liabilities and partners equity	$ 345.1	$ 407.3

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	($ in millions, except per unit amounts)			
Operating revenues:				
Sales of natural gas, NGLs and condensate	$ 42.0	$ 127.4	$ 86.3	$ 233.1
Sales of natural gas, NGLs and condensate to affiliates	46.1	17.3	115.3	33.7
Transportation and processing services	3.6	2.4	7.4	5.5
Transportation and processing services to affiliates	3.3	3.1	6.0	5.3
Total operating revenues	95.0	150.2	215.0	277.6
Operating costs and expenses:				
Purchases of natural gas and NGLs	69.0	129.2	156.2	237.0
Purchases of natural gas and NGLs from affiliates	6.7	5.6	21.6	10.1
Operating and maintenance expense	3.0	2.9	7.3	6.5
Depreciation and amortization expense	2.9	2.9	5.9	5.9
General and administrative expense	2.2		4.9	
General and administrative expense affiliates	1.4	2.0	2.8	3.6
Total operating costs and expenses	85.2	142.6	198.7	263.1
Operating income	9.8	7.6	16.3	14.5
Earnings from equity method investment	0.1	0.1	0.1	0.3
Interest income	1.5		3.0	
Interest expense	2.6		5.2	
Net income	8.8	7.7	14.2	14.8
Less:				
Net income attributable to DCP Midstream Partners Predecessor		(7.7)		(14.8)
General partner interest in net income	(0.2)		(0.3)	
Net income allocable to limited partners	$ 8.6	$	$ 13.9	$
Net income per limited partner unit basic and diluted	$ 0.47	$	$ 0.79	$
Weighted average limited partners units outstanding basic and diluted	17.5		17.5	

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	($ in millions)			
Net income	$ 8.8	$ 7.7	$ 14.2	$ 14.8
Other comprehensive loss:				
Net unrealized losses on cash flow hedges	(2.4)		(2.8)	
Reclassification of cash flow hedges into earnings	(0.5)		(0.7)	
Total other comprehensive loss	(2.9)		(3.5)	
Total comprehensive income	$ 5.9	$ 7.7	$ 10.7	$ 14.8

See accompanying notes to condensed consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	($ in millions)	
OPERATING ACTIVITIES:		
Net income	$ 14.2	$ 14.8
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	5.9	5.9
Undistributed earnings from equity method investments	(0.1)	(0.3)
Other, net	(1.3)	
Change in operating assets and liabilities which provided (used) cash:		
Accounts receivable	47.2	(1.8)
Net unrealized losses (gains) on non-trading derivative and hedging transactions	0.5	(0.1)
Inventories	0.1	
Accounts payable	(57.3)	0.2
Accrued interest	(0.2)	
Other current assets and liabilities	1.8	(0.9)
Other non-current assets and liabilities		0.1
Net cash provided by operating activities	10.8	17.9
INVESTING ACTIVITIES:		
Capital expenditures	(6.9)	(2.9)
Proceeds from sales of assets	0.1	0.1
Purchases of available-for-sale securities	(4,249.8)	
Proceeds from sales of available-for-sale securities	4,248.8	
Net cash used in investing activities	(7.8)	(2.8)
FINANCING ACTIVITIES:		
Payment on long-term debt	(20.1)	
Distributions to partners	(8.0)	
Contributions from Duke Energy Field Services, LLC	3.2	
Net change in advances from Duke Energy Field Services, LLC		(15.1)
Net cash used in financing activities	(24.9)	(15.1)
Net change in cash and cash equivalents	(21.9)	
Cash and cash equivalents, beginning of period	42.2	
Cash and cash equivalents, end of period	$ 20.3	$
Supplementary cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ 5.4	$

See accompanying notes to condensed consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Description of Business and Basis of Presentation

We are engaged in the business of gathering, compressing, treating, processing, transporting and selling natural gas and producing, transporting and selling natural gas liquids, or NGLs.

Our partnership includes our North Louisiana system assets, or Minden, Ada and PELICO, our NGL transportation pipeline, or Seabreeze, and our 45% equity method investment in the Black Lake Pipe Line Company, or Black Lake, that were contributed to us on December 7, 2005 by Duke Energy Field Services, LLC, or DEFS. DEFS is owned 50% by Duke Energy Corporation, or Duke Energy, and 50% by ConocoPhillips. The condensed consolidated financial statements include a 50% equity interest in Black Lake for the period beginning January 1, 2005 through June 30, 2005. Upon closing of our initial public offering on December 7, 2005, DEFS retained a 5% interest in Black Lake. An affiliate of BP owns the remaining interest and is the operator of Black Lake.

We closed our initial public offering of 10,350,000 common units at a price of $21.50 per unit on December 7, 2005. Proceeds from the initial public offering were $206.4 million, net of offering costs. Concurrent with the initial public offering, DEFS contributed the assets described above to us and retained (i) a 2% general partner interest; (ii) 7,142,857 subordinated units; and (iii) 7,143 common units, representing in aggregate an approximate 42% interest in our partnership. Our general partner is DCP Midstream GP, LP, a wholly-owned subsidiary of DEFS. See Note 4 for information related to the distribution rights of the common and subordinated unitholders and the incentive distribution rights held by the general partner.

DEFS directs our business operations through its ownership and control of our general partner. DEFS and its affiliates employees provide administrative support to us and operate our assets.

The condensed consolidated financial statements include our accounts, and prior to December 7, 2005 the assets, liabilities and operations contributed to us by DEFS and its wholly-owned subsidiaries, which we refer to as DCP Midstream Partners Predecessor, upon the closing of our initial public offering, and have been prepared in accordance with accounting principles generally accepted in the United States of America. The condensed consolidated financial statements of DCP Midstream Partners Predecessor have been prepared from the separate records maintained by DEFS and may not necessarily be indicative of the conditions that would have existed or the results of operations if DCP Midstream Partners Predecessor had been operated as an unaffiliated entity. All significant intercompany balances and transactions have been eliminated in consolidation. Transactions between us and other DEFS operations have been identified in the condensed consolidated financial statements as transactions between affiliates (see Note 6).

The accompanying unaudited condensed consolidated financial statements in this quarterly report on Form 10-Q have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission. Accordingly these condensed consolidated financial statements reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective interim periods. Certain information and notes normally included in our annual financial statements have been condensed in or omitted from these interim financial statements pursuant to such rules and regulations. These condensed consolidated financial statements and other information included in this quarterly report on Form 10-Q should be read in conjunction with the consolidated financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2005.

2. Summary of Significant Accounting Policies

Use of Estimates Conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the amounts reported in the financial statements and notes. Although these estimates are based on management s best available knowledge of current and expected future events, actual results could differ from those estimates.

Short-Term and Restricted Investments Short-term investments were $2.8 million at June 30, 2006. There were no short-term investments at December 31, 2005. Restricted investments were $100.0 million and $100.4 million at June 30, 2006 and December 31, 2005, respectively. These investments primarily consist of commercial paper and various other high-grade debt securities. The restricted investments are used as collateral to secure the term loan portion of the credit facility and are to be used only for future capital or acquisition expenditures. Both the restricted and short-term investments are classified as available-for-sale securities under Statement of Financial Accounting Standards, or SFAS, 115, *Accounting for Certain Investments in Debt* *and Equity Securities,* as management does not intend to hold them to maturity nor are they bought or sold with the objective of generating profits on short-term differences in prices. These investments are recorded at fair value with changes in fair value recorded as unrealized holding gains or losses in accumulated other comprehensive (loss) income, or AOCI. At both June 30, 2006 and December 31, 2005, no amounts related to these investments were deferred in AOCI. Due to the short-term, highly liquid nature of the securities held by us and as interest rates are re-set on a daily, weekly or monthly basis, the cost, including accrued interest on investments, approximates fair value.

Accounting for Risk Management and Hedging Activities and Financial Instruments Each derivative not qualifying for the normal purchases and normal sales exception under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* or SFAS 133, as amended, is recorded on a gross basis in the condensed consolidated balance sheets at its fair value as unrealized gains or unrealized losses on non-trading derivative and hedging transactions. Derivative assets and liabilities remain classified in our condensed consolidated balance sheets as unrealized gains or unrealized losses on non-trading derivative and hedging transactions at fair value until the contractual settlement period occurs.

All derivative activity reflected in the condensed consolidated financial statements for periods prior to December 7, 2005 was transacted by DEFS and its subsidiaries prior to our initial public offering and was transferred and/or allocated to us. All derivative activity reflected in the condensed consolidated financial statements from December 7, 2005 has been and will be transacted by us, although DEFS personnel execute various transactions on our behalf (see Note 6). Management designated each energy commodity derivative as non-trading. Certain non-trading derivatives are further designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or normal purchases or normal sales, while certain non-trading derivatives, which are related to asset-based activity, are designated as non-trading derivative activity. For the periods presented, we did not have any non-trading derivative activity. We did have cash flow and fair value hedge activity and normal purchases and normal sales activity included in these condensed consolidated financial statements. For each derivative, the accounting method and presentation of gains and losses or revenue and expense in the condensed consolidated statements of operations are as follows:

Classification of Contract	Accounting Method	Presentation of Gains & Losses or Revenue & Expense
Non-trading derivative activity	Mark-to-market (a)	Net basis in gains and losses from non-trading derivative activity
Cash flow hedge	Hedge method (b)	Gross basis in the same statement of operations category as the related hedged item
Fair value hedge	Hedge method (b)	Gross basis in the same statement of operations category as the related hedged item
Normal purchases or normal sales	Accrual method (c)	Gross basis upon settlement in the corresponding statement of operations category based on purchase or sale

(a) Mark-to-market An accounting method whereby the change in the fair value of the asset or liability is recognized in the results of operations in gains and losses from non-trading derivative activity during the current period.

(b) Hedge method An accounting method whereby the effective portion of the change in the fair value of the asset or liability is recorded as a balance sheet adjustment and there is no recognition in the results of operations for the effective portion until the service is provided or the associated delivery period occurs.

(c) Accrual method An accounting method whereby there is no recognition in the results of operations for changes in fair value of a contract until the service is provided or the associated delivery period occurs.

Cash Flow and Fair Value Hedges For derivatives designated as a cash flow hedge or a fair value hedge, management prepares formal documentation of the hedge in accordance with SFAS 133. In addition, management formally assesses, both at the inception of the hedge and on an ongoing basis, whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. All components of each derivative gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted.

The fair value of a derivative designated as a cash flow hedge is recorded in the condensed consolidated balance sheets as unrealized gains or unrealized losses on non-trading derivative and hedging transactions. The effective portion of the change in fair value of a derivative designated as a cash flow hedge is recorded in partners equity as AOCI and the ineffective portion is recorded in the condensed consolidated statements of operations. During the period in which the hedged transaction occurs, amounts in AOCI associated with the hedged transaction are reclassified to the condensed consolidated statements of operations in the same accounts as the item being hedged. Hedge accounting is discontinued prospectively when it is determined that the derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged transaction will occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the mark-to-market accounting method prospectively. The derivative continues to be carried on the condensed consolidated balance sheets at its fair value; however, subsequent changes in its fair value are recognized in current period earnings. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the hedged transaction occurs, unless it is probable that the hedged transaction will not occur, in which case, the gains and losses that were previously deferred in AOCI will be immediately recognized in current period earnings.

The fair value of a derivative designated as a fair value hedge is recorded in the condensed consolidated balance sheets as unrealized gains or unrealized losses on non-trading derivative and hedging transactions. We recognize the gain or loss on the derivative instrument, as well as the offsetting loss or gain on the hedged item in earnings in the current period. All derivatives designated and accounted for as fair value hedges are classified in the same category as the item being hedged in the results of operations.

Valuation When available, quoted market prices or prices obtained through external sources are used to verify a contract s fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected correlations with quoted market prices.

Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

Property, Plant and Equipment Property, plant and equipment are recorded at historical cost. Depreciation is computed using the straight-line method over the estimated useful lives of the assets. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

We have adopted SFAS No. 143, *Accounting for Asset Retirement Obligations,* or SFAS 143, and Financial Accounting Standards Board Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations,* or FIN 47, which address financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The standard and interpretation apply to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability increases due to the passage of time based on the time value of money until the obligation is settled. FIN 47 requires the recognition of a liability for a conditional asset retirement obligation as soon as the fair value of the liability can be reasonably estimated. A conditional asset retirement obligation is defined as an unconditional legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity.

Impairment of Long-Lived Assets Management periodically evaluates whether the carrying value of long-lived assets has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. This evaluation is based on undiscounted cash flow projections. The carrying amount is not recoverable if it exceeds the undiscounted sum of cash flows expected to result from the use and eventual disposition of the asset. Management considers various factors when determining if these assets should be evaluated for impairment, including but not limited to:

- significant adverse change in legal factors or in the business climate;

a current-period operating or cash flow loss combined with a history of operating or cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;

an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;

significant adverse changes in the extent or manner in which an asset is used or in its physical condition;

- a significant change in the market value of an asset; or
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset s carrying value over its fair value. Management assesses the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales, internally developed discounted cash flow analysis and analysis from outside advisors. Significant changes in market conditions resulting from events such as the condition of an asset or a change in management s intent to utilize the asset would generally require management to reassess the cash flows related to the long-lived assets.

Impairment of Equity Method Investment We evaluate our equity method investment for impairment when events or changes in circumstances indicate, in management s judgment, that the carrying value of such investment may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, management compares the estimated fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. Management assesses the fair value of its equity method investment using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales, internally developed discounted cash flow analysis and analysis from outside advisors. If the estimated fair value is less than the carrying value and management considers the decline in value to be other than temporary, the excess of the carrying value over the estimated fair value is recognized in the financial statements as an impairment.

Revenue Recognition Our primary types of sales and service activities reported as operating revenue include:

- sales of natural gas, NGLs and condensate;
- natural gas gathering, processing and transportation, from which we generate revenues primarily through the compression, gathering, treating, processing and transportation of natural gas; and
- NGL transportation from which we generate revenues from transportation fees.

Revenues associated with sales of natural gas, NGLs and condensate are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery occurs. Revenues associated with transportation and processing fees are recognized as the services are provided.

For gathering and processing services, we receive either fees or commodities from natural gas producers depending on the type of contract. Commodities received are in turn sold and recognized as revenue in accordance with the criteria outlined above. Under the percentage-of-proceeds contract type, we are paid for our services by keeping a percentage of the NGLs produced and a percentage of the residue gas resulting from processing the natural gas. Under the percentage-of-index contract type, we purchase wellhead natural gas and sell processed natural gas and NGLs to third parties.

We recognize revenues for non-trading derivative activity net in the condensed consolidated statements of operations as (losses) gains from non-trading derivative activity, in accordance with EITF Issue No. 02-03, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.* These activities include mark-to-market gains and losses on energy derivative contracts and the financial or physical settlement of energy derivative contracts.

We generally report revenues gross in the condensed consolidated statements of operations, in accordance with EITF Issue No. 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent.* Except for fee-based agreements, we act as the principal in these transactions, take title to the product, and incur the risks and rewards of ownership.

Equity-Based Compensation Under our long term incentive plan, or the Plan, equity-based instruments may be granted to our key employees. DCP Midstream GP, LLC adopted the Plan for employees, consultants and directors of DCP Midstream GP, LLC and its affiliates who perform services for us. The Plan provides for the grant of unvested units, phantom units, unit options and substitute awards and the grant of distribution equivalent rights. Subject to adjustment for certain events, an aggregate of

850,000 common units may be delivered pursuant to awards under the Plan. Awards that are canceled, forfeited or are withheld to satisfy DCP Midstream GP, LLC s tax withholding obligations are available for delivery pursuant to other awards. The Plan is administered by the compensation committee of DCP Midstream GP, LLC s board of directors. We first granted awards under the Plan during the three months ended March 31, 2006.

Effective January 1, 2006, we adopted the provisions of SFAS No. 123 (Revised 2004), or SFAS 123R, *Share-Based Payment.* SFAS 123R establishes accounting for stock-based awards exchanged for employee and non-employee services. Accordingly, equity classified stock-based compensation cost is measured at grant date, based on the estimated fair value of the award, and is recognized as expense over the vesting period. Liability classified stock-based compensation cost is remeasured at each reporting date and is recognized over the requisite service period. Compensation expense for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award. Awards granted to non-employees are accounted for under the provisions of EITF No. 96-18, *Accounting for Equity Instruments That Are Issued to Other Than Employees for Acquiring, or in Conjunction with Selling, Goods or Services.*

Since no equity-based awards were outstanding or granted during the three and six months ended June 30, 2005, pro forma disclosures are not necessary relating to what earnings available for limited partners, basic earnings per limited partner unit and diluted earnings per limited partner unit would have been if we had applied the fair value recognition provisions of SFAS 123R to all equity-based compensation awards.

Net Income per Limited Partner Unit Basic and diluted net income per limited partner unit is calculated by dividing limited partners interest in net income, less any applicable pro forma general partner incentive distributions under EITF Issue No. 03-6, *Participating Securities and the Two-Class Method Under FASB Statement No. 128,* or EITF 03-6, by the weighted average number of outstanding limited partner units during the period (see Note 5).

3. Recent Accounting Pronouncements

SFAS No. 154, or SFAS 154, Accounting Changes and Error Corrections. In June 2005, the FASB issued SFAS 154, a replacement of APB Opinion No. 20, *Accounting Changes,* and FASB Statement No. 3, *Reporting Accounting Changes in Interim Financial Statements.* Among other changes, SFAS 154 requires that a voluntary change in accounting principle be applied retrospectively with all prior period financial statements presented on the new accounting principle, unless it is impracticable to do so. SFAS 154 also provides that (1) a change in method of depreciating or amortizing a long-lived nonfinancial asset be accounted for as a change in estimate (prospectively) that was effected by a change in accounting principle, and (2) carried forward without change the guidance within Opinion 20 for reporting the correction of an error in previously issued financial statements and a change in accounting estimate. The adoption of SFAS 154 on January 1, 2006 did not have an impact on our consolidated results of operations, cash flows or financial position.

Emerging Issues Task Force Issue No. 04-13, or EITF 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty. In September 2005, the FASB ratified the EITF s consensus on Issue 04-13, which requires an entity to treat sales and purchases of inventory between the entity and the same counterparty as one transaction for purposes of applying APB Opinion No. 29, or APB 29, when such transactions are entered into in contemplation of each other. When such transactions are legally contingent on each other, they are considered to have been entered into in contemplation of each other. The EITF also agreed on other factors that should be considered in determining whether transactions have been entered into in contemplation of each other. EITF 04-13 is to be applied to new arrangements that we enter into in reporting periods beginning after March 15, 2006. The adoption of EITF 04-13 did not have a material impact on our consolidated results of operations, cash flows or financial position.

4. Partnership Equity and Distributions

General. Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date, as determined by the general partner.

Definition of Available Cash. Available cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

less the amount of cash reserves established by the general partner to:

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- provide for the proper conduct of our business;

- comply with applicable law, any of our debt instruments or other agreements; or

- provide funds for distributions to the unitholders and to the general partner for any one or more of the next four quarters;

plus, if the general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination of available cash for the quarter.

General Partner Interest and Incentive Distribution Rights. The general partner is entitled to 2% of all quarterly distributions that we make prior to its liquidation. This general partner interest is represented by 357,143 equivalent units. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner s initial 2% interest in these distributions will be reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest.

The incentive distribution rights held by the general partner entitles it to receive an increasing share of available cash when pre-defined distribution targets are achieved. The general partner s incentive distribution rights are not reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest. Please read the *Distributions of Available Cash during the Subordination Period and Distributions of Available Cash after the Subordination Period* sections below for more details about the distribution targets and their impact on the general partner s incentive distribution rights.

Subordinated Units. All of the subordinated units are held by DEFS. The partnership agreement provides that, during the subordination period, the common units will have the right to receive distributions of available cash each quarter in an amount equal to $0.35 per common unit, or the Minimum Quarterly Distribution , plus any arrearages in the payment of the Minimum Quarterly Distribution on the common units from prior quarters, before any distributions of available cash may be made on the subordinated units. These units are deemed subordinated because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the Minimum Quarterly Distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units. The subordination period will end, and the subordinated units will convert to common units, on a one for one basis, when certain distribution requirements, as defined in the partnership agreement, have been met. The earliest date at which the subordination period may end is December 31, 2008 and 50% of the subordinated units may convert to common units as early as December 31, 2007. The rights of the subordinated unitholders, other than the distribution rights described above, are substantially the same as the rights of the common unitholders.

Distributions of Available Cash during the Subordination Period. The partnership agreement requires that we make distributions of available cash for any quarter during the subordination period in the following manner:

- *first,* 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to the Minimum Quarterly Distribution for that quarter;

- *second,* 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the Minimum Quarterly Distribution on the common units for any prior quarters during the subordination period;

- *third,* 98% to the subordinated unitholders, pro rata, and 2% to the general partner, until we distribute for each subordinated unit an amount equal to the Minimum Quarterly Distribution for that quarter; and

- *fourth,* 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder receives a total of $0.4025 per unit for that quarter (the First Target Distribution);

fifth, 85% to all unitholders, pro rata, and 15% to the general partner, until each unitholder receives a total of $0.4375 per unit for that quarter (the Second Target Distribution);

sixth, 75% to all unitholders, pro rata, and 25% to the general partner, until each unitholder receives a total of $0.525 per unit for that quarter (the Third Target Distribution); and

thereafter, 50% to all unitholders, pro rata, and 50% to the general partner (the Fourth Target Distribution).

Distributions of Available Cash after the Subordination Period. The partnership agreement requires that we make distributions of available cash from operating surplus for any quarter after the subordination period in the following manner:

first, 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder receives a total of $0.4025 per unit for that quarter;

second, 85% to all unitholders, pro rata, and 15% to the general partner, until each unitholder receives a total of $0.4375 per unit for that quarter;

third, 75% to all unitholders, pro rata, and 25% to the general partner, until each unitholder receives a total of $0.525 per unit for that quarter; and

thereafter, 50% to all unitholders, pro rata, and 50% to the general partner.

In February 2006, we paid a cash distribution of $0.095 per unit to unitholders of record on February 3, 2006. That distribution represented the pro rata portion of our Minimum Quarterly Distribution of $0.35 per unit for the period December 7, 2005, the closing of our initial public offering, through December 31, 2005.

In May 2006, we paid a cash distribution of $0.35 per unit to unitholders of record on May 5, 2006.

On July 27, 2006, the board of directors of DCP Midstream Partners general partner declared a quarterly distribution of $0.38 per unit, payable on August 14, 2006 to unitholders of record on August 4, 2006.

5. Net Income per Limited Partner Unit

Our net income is allocated to the general partner and the limited partners, including the holders of the subordinated units, in accordance with their respective ownership percentages, after giving effect to incentive distributions paid to the general partner.

EITF 03-6 addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock.

EITF 03-6 requires that securities that meet the definition of a participating security be considered for inclusion in the computation of basic earnings per unit using the two-class method. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of the partnership agreement, regardless of whether the general partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the general partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

EITF 03-6 does not impact our overall net income or other financial results; however, in periods in which aggregate net income exceeds the First Target Distribution level, it will have the impact of reducing net income per limited partner unit. This result occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the incentive distribution rights of the general partner, even though we make distributions on the basis of available cash and not earnings. In periods in which our aggregate net income per unit does not exceed the First Target Distribution level, EITF 03-6 does not have any impact on our calculation of earnings per limited partner unit. During the three months ended June 30, 2006, our aggregate net income per unit exceeded the Second Target Distribution level, and as a result we allocated $0.3 million in additional earnings to the general partner in accordance with EITF 03-6. During the six months ended June 30, 2006, our aggregate net income per unit was less than the First Target Distribution level and EITF 03-6 did not impact earnings per unit.

Basic and diluted net income per limited partner unit is calculated by dividing limited partners interest in net income, less pro forma general partner incentive distributions under EITF 03-6, by the weighted average number of outstanding limited partner units during the period.

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The following table illustrates our calculation of net income per limited partner unit for the three and six months ended June 30, 2006 ($ in millions):

	Three Months Ended June 30, 2006	Six Months Ended June 30, 2006
Net income	$ 8.8	$ 14.2
Less: General partner interest in net income	(0.2)	(0.3)
Limited partners interest in net income (Note 4)	8.6	13.9
Additional earnings allocation to general partner	(0.3)	
Net income available to limited partners under EITF 03-6	$ 8.3	$ 13.9
Net income per limited partner unit basic and diluted	$ 0.47	$ 0.79

6. Agreements and Transactions with Affiliates

DEFS

Omnibus Agreement

Upon the closing of our initial public offering, we entered into an Omnibus Agreement with DEFS. Under the Omnibus Agreement, we are required to pay DEFS for salaries of operating personnel and employee benefits for DEFS employees operating our assets as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DEFS on our behalf, associated with our assets. We also pay an annual fee of $4.8 million to DEFS. The annual fee is for centralized corporate functions performed by DEFS on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. In the second quarter of 2006, we amended the Omnibus Agreement. The amendment clarifies that the annual fee of $4.8 million under the agreement is fixed at such amount, subject to annual increases in the consumer price index and increases in connection with the expansion of our operations through the acquisition or construction of new assets or businesses.

For the six months ended June 30, 2005, our share of general and administrative expenses and employee retirement and medical plans and other service fees was allocated based on our proportionate net investment (consisting of property, plant and equipment, net, equity method investment, and intangible assets, net) compared to DEFS net investment. In management s estimation, the allocation methodologies used are reasonable and result in an allocation to us of our costs of doing business borne by DEFS. Further details regarding the Omnibus Agreement are included in Note 7 in our annual report on Form 10-K for the year ended December 31, 2005.

Other Agreements and Transactions with DEFS

Prior to our initial public offering on December 7, 2005, we participated in DEFS cash management program. As a result, we had no cash balances prior to December 7, 2005 and all cash management activity was managed by DEFS on our behalf, including collection of receivables, payment of payables, and the settlement of sales and purchases transactions between us and DEFS, which were recorded as parent advances and included in accounts receivable affiliates or accounts payable affiliates. Subsequent to the initial public offering, we maintain separate cash accounts, which are managed by DEFS.

DEFS owns certain assets and is party to certain contractual relationships around our PELICO system that are periodically used for the benefit of PELICO. DEFS is able to source natural gas upstream of PELICO and deliver it to the inlet of the PELICO system, and is able to take natural gas from the outlet of the PELICO system and market it downstream of PELICO. Because of DEFS ability to move natural gas around PELICO, there are certain contractual relationships around PELICO that define how natural gas is bought and sold between DEFS and DCP.

Effective December 2005, we entered into a contract with a subsidiary of DEFS that provides that DEFS will purchase natural gas and transport it to the PELICO system where we will buy the gas from DEFS at its weighted average cost delivered to the PELICO system plus a contractually agreed to marketing fee and other related adjustments. In addition, for a significant portion of the gas that we sell out of our PELICO system, DEFS will purchase that natural gas from us and transport it to a sales point at a price equal to its net weighted average sales price less a contractually agreed to marketing fee and other related adjustments. We generally report revenues and purchases associated with these activities gross in the condensed consolidated statements of operations as sales of natural gas, NGLs and condensate to affiliates and purchases of natural gas and NGLs from affiliates.

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The above agreement was amended and restated effective February 2006 in response to DEFS securing additional access to natural gas for our PELICO system. The revised agreement is described below:

The revised agreement requires that DEFS supply PELICO s system requirements that exceed its on-system supply. Accordingly, DEFS purchases natural gas and transports it to our PELICO system where we buy the gas from DEFS at the actual acquisition cost plus transportation service charges incurred. We generally report purchases associated with these activities gross in the condensed consolidated statements of operations as purchases of natural gas, NGLs and condensate from affiliates.

If our PELICO system has volumes in excess of the on-system demand, DEFS will purchase the excess natural gas from us and transport it to sales points at an index based price less a contractually agreed to marketing fee. We generally report revenues associated with these activities gross in the condensed consolidated statements of operations as sales of natural gas, NGLs and condensate to affiliates.

In addition, DEFS may purchase other excess natural gas volumes at certain PELICO outlets for a price that equals the original PELICO purchase price from DEFS plus a portion of the index differential between upstream sources to certain downstream indices with a maximum differential and a minimum differential plus a fixed fuel charge and other related adjustments. We generally report revenues and purchases associated with these activities net in the condensed consolidated statements of operations as transportation and processing services to affiliates.

Effective December 2005, we entered into a contractual arrangement with a subsidiary of DEFS that provides that for certain industrial end-user customers of the PELICO system we may sell aggregated natural gas to a subsidiary of DEFS which in turn would resell natural gas to these customers. The sales price to the subsidiary of DEFS is equal to that subsidiary of DEFS net weighted average sales price delivered from the PELICO system less a contractually agreed to marketing fee, which is recorded in the condensed consolidated statements of operations as sales of natural gas, NGLs and condensate to affiliates.

Effective December 2005, we entered into a contractual arrangement with a subsidiary of DEFS that provides that DEFS will purchase the NGLs that were historically purchased by the Seabreeze pipeline, and DEFS will pay us to transport the NGLs pursuant to a fee-based rate that will be applied to the volumes transported. We have entered into this fee-based contractual arrangement with the objective of generating approximately the same operating income per barrel transported that we realized when we were the purchaser and seller of NGLs. We do not take title to the products transported on the NGL pipeline; rather, the shipper retains title and the associated commodity price risk. DEFS is the sole shipper on the Seabreeze pipeline under a 17-year transportation agreement expiring in 2022. The Seabreeze pipeline records primarily fee-based transportation revenue under this agreement recorded as transportation and processing services to affiliates.

We sell NGLs and condensate from our Minden and Ada processing plants and condensate from our PELICO system to a subsidiary of DEFS equal to that subsidiary of DEFS net weighted average sales price adjusted for transportation and other charges from the tailgate of the respective asset, which is recorded in the condensed consolidated statements of operations as sales of natural gas, NGLs and condensate to affiliates.

Management anticipates continuing to purchase these commodities from and sell these commodities to DEFS in the ordinary course of business.

In the second quarter of 2006, we entered into a letter agreement with DEFS whereby DEFS will make capital contributions to us as reimbursement for capital projects which were forecasted to be completed prior to our initial public offering, but were not completed by that date. Pursuant to the letter agreement, DEFS made capital contributions to us in the second quarter of 2006 of $3.2 million to reimburse us for the capital costs we incurred in the first and second quarters of 2006 for these capital projects. Included in our consolidated balance sheet as of June 30, 2006 as accounts receivable affiliates is approximately $0.1 million from DEFS for reimbursable capital costs. DEFS will make additional capital contributions to us in the future until all these projects have been completed.

Duke Energy

We charge transportation fees to Duke Energy and its affiliates. Management anticipates continuing to provide transportation services to Duke Energy and its affiliates in the ordinary course of business.

ConocoPhillips

We have multiple agreements covering a variety of services provided to ConocoPhillips and its affiliates by us. The agreements include fee-based and percentage of proceeds gathering and processing arrangements and gas purchase and gas sales agreements. Management anticipates continuing to purchase from and sell these commodities to ConocoPhillips and its affiliates in the ordinary course of business. In addition, we may be reimbursed by ConocoPhillips for certain capital projects where the work is performed by us. We received $1.2 million and $0.1 million of capital reimbursements during the six months ended June 30, 2006 and 2005, respectively.

The following table summarizes the transactions with DEFS, Duke Energy and ConocoPhillips as described above ($ in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
Duke Energy Field Services:				
Sales of natural gas, NGLs and condensate	$46.0	$14.3	$115.2	$29.2
Transportation and processing services	$ 1.3	$	$ 2.5	$
Purchases of natural gas and NGLs	$ 4.8	$ 0.3	$ 16.4	$ 0.3
General and administrative expense	$ 1.4	$ 2.0	$ 2.8	$ 3.6
Duke Energy:				
Transportation and processing services	$	$ 0.1	$	$ 0.2
Purchases of natural gas and NGLs	$	$ 1.6	$	$ 1.6
ConocoPhillips:				
Sales of natural gas, NGLs and condensate	$ 0.1	$ 3.0	$ 0.1	$ 4.5
Transportation and processing services	$ 2.0	$ 3.0	$ 3.5	$ 5.1
Purchases of natural gas and NGLs	$ 1.9	$ 3.7	$ 5.2	$ 8.2

We had accounts receivable and accounts payable with affiliates as follows ($ in millions):

	June 30, 2006	**December 31, 2005**
Duke Energy Field Services:		
Accounts receivable	$1.5	$ 53.5
Accounts payable	$1.6	$ 39.5
Duke Energy:		
Accounts receivable	$	$ 0.4
Accounts payable	$1.1	$
ConocoPhillips:		
Accounts receivable	$4.0	$ 2.6
Accounts payable	$0.7	$ 2.5

7. Risk Management and Hedging Activities, Credit Risk and Financial Instruments

Commodity price risk Our principal operations of gathering, processing, and transportation of natural gas, and the accompanying operations of producing, transporting and marketing of NGLs create commodity price risk due to market fluctuations in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil. As an owner and operator of natural gas processing and other midstream assets, we have an inherent exposure to market variables and commodity price risk. The amount and type of price risk is dependent on the underlying natural gas contracts entered into to purchase and process raw natural gas. Risk is also dependent on the types and mechanisms for sales of natural gas and NGLs and related products produced, processed, transported or stored.

Credit risk In the Natural Gas Services segment, we sell natural gas to marketing affiliates of natural gas pipelines, marketing affiliates of integrated oil companies, marketing affiliates of DEFS, national wholesale marketers, industrial end-users and gas-fired power plants. In the NGL Logistics segment, our principal customers include an affiliate of DEFS, producers and marketing companies. This concentration of credit risk may affect our overall credit risk in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, management analyzes the counterparties financial condition prior to entering into an agreement, establishes credit limits and monitors the appropriateness of these limits on an ongoing basis. We operate under DEFS corporate credit policy. DEFS corporate credit policy prescribes the use of master collateral agreements to mitigate credit exposure. Collateral agreements provide for a counterparty to post cash or letters of credit for exposure in excess of an established threshold. The threshold amount represents an open credit limit, determined in accordance with DEFS credit policy. The collateral agreements also provide that the inability to post collateral is sufficient cause to terminate a contract and liquidate all positions. In addition, our standard natural gas and NGL sales contracts contain adequate assurance provisions which allow us to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment in a form satisfactory to us.

Commodity cash flow hedges In September 2005, we executed a series of derivative financial transactions which have been designated as cash flow hedges of the price risk associated with our forecasted sales of natural gas, NGLs and condensate. As a result of those transactions, we hedged approximately 80% of our expected natural gas and NGL commodity price risk effective January 1, 2006 relating to our percentage of proceeds gathering and processing contracts and 80% of our expected condensate commodity price risk relating to condensate recovered from gathering operations through 2010.

In June 2006, we executed a derivative financial transaction which has been designated as a cash flow hedge of the price risk associated with our 2011 forecasted sales of condensate. As a result of this transaction, we hedged approximately 60% of our expected 2011 condensate commodity price risk relating to condensate recovered from gathering operations.

We use natural gas and crude oil swaps to hedge the impact of market fluctuations in the price of NGLs, natural gas and condensate. The effective portion of the change in fair value of a derivative designated as a cash flow hedge is accumulated in AOCI, and the ineffective portion is recorded in the condensed consolidated statements of operations. For the three and six months ended June 30, 2006, we recognized losses of approximately $0.1 million and $0.5 million, respectively, due to the ineffectiveness of these cash flow hedges. For the three and six months ended June 30, 2006, gains of $0.5 million and $0.7 million, respectively, were reclassified into earnings as a result of settlements. For both the three and six months ended June 30, 2006, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring or due to a derivative no longer qualifying as an effective hedge. All components of each derivative s gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted.

During the period in which the hedged transaction occurs, amounts in AOCI associated with the hedged transaction will be reclassified to the condensed consolidated statements of operations in the same accounts as the item being hedged. As of June 30, 2006 and December 31, 2005, there was a net deferred loss of $4.4 million and a net deferred gain of $0.4 million, respectively, related to commodity cash flow hedge derivative contracts in AOCI. As of June 30, 2006, $1.2 million of deferred net losses on derivative instruments in AOCI are expected to be reclassified into earnings during the next 12 months as the hedged transactions occur; however, due to the volatility of the commodities markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings.

Commodity fair value hedges We use fair value hedges to hedge exposure to changes in the fair value of an asset or a liability (or an identified portion thereof) that is attributable to fixed price risk. We may hedge producer price locks (fixed price gas purchases) to reduce our exposure to fixed price risk by swapping the fixed price risk for a floating price position (New York Mercantile Exchange or index-based).

For the three and six months ended June 30, 2006 and 2005, the gains or losses representing the ineffective portion of our fair value hedges were not significant. All components of each derivative s gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted. During the three and six months ended June 30, 2006 and 2005, there were no firm commitments that no longer qualified as fair value hedge items and therefore, we did not recognize an associated gain or loss.

Commodity non-trading derivative activity The marketing of energy related products and services exposes us to the fluctuations in the market values of exchanged instruments. Our marketing program is designed to realize margins related to fluctuations in commodity prices and differences in natural gas prices at various receipt and delivery points across the system for our Natural Gas Services segment. DEFS manages our marketing portfolios in accordance with our Risk Management Policy which limits exposure to market risk.

Interest rate cash flow hedge On March 14, 2006, we entered into interest rate swap agreements to hedge the variable interest rate on a portion of the balance outstanding under our credit agreement. The interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in AOCI in the accompanying condensed consolidated balance sheet. As of June 30, 2006, a gain of $1.3 million was deferred in AOCI related to these swaps. As of June 30, 2006, $0.3 million of deferred net gains on derivative instruments in AOCI are expected to be reclassified into earnings during the next 12 months as the hedged transactions occur; however, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings. Ineffective portions of changes in fair value are recognized in earnings. The agreements reprice prospectively approximately every 90 days and expire on December 7, 2010. Under the terms of the interest rate swap agreements, we pay a fixed rate of 5.08% and receive interest payments based on 3-month LIBOR on a total notional amount of $75.0 million. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense. The agreements are with major financial institutions, which are expected to fully perform under the terms of the agreements.

8. Debt

Credit Facility with Financial Institutions On December 7, 2005, we entered into a 5-year credit agreement, or the Credit Agreement, providing a $250.0 million revolving credit facility and a $100.1 million term loan facility. The unused portion of the revolving credit facility may be used for letters of credit. The Credit Agreement matures on December 7, 2010. The Credit Agreement prohibits us from making distributions of available cash to unitholders if any default or event of default (as defined in the Credit Agreement) exists. The Credit Agreement requires us to maintain at all times (commencing with the quarter ending March 31, 2006) a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Credit Agreement) of less than or equal to 4.75 to 1.0 (and on a temporary basis for not more than three consecutive quarters following the acquisition of assets in the midstream energy business of not more than 5.25 to 1.0); and maintain at the end of each fiscal quarter an interest coverage ratio (defined to be the ratio of adjusted EBITDA, as defined by the Credit Agreement to be earnings before interest, taxes and depreciation and amortization and other non-cash adjustments, for the four most recent quarters to interest expense for the same period) of greater than or equal to 3.0 to 1.0. The term loan bears interest at a rate equal to either LIBOR plus 0.15%, the Federal Funds rate plus 0.5%, or the Wachovia Bank prime rate. The term loan s interest rate as of June 30, 2006 was 5.39%. The revolving credit facility bears interest at a rate equal to LIBOR plus an applicable margin, which ranges from 0.27% to 1.025% based on leverage level or credit rating, or the higher of the federal funds rate plus 0.50% or Wachovia Bank s prime rate plus an applicable margin of 0% to 0.025% based on leverage level. The revolving credit facility s weighted average interest rate as of June 30, 2006 was 5.80%. The revolving credit facility incurs an annual facility fee of 0.08% to 0.35% depending on the applicable leverage level or debt rating. This fee is paid on drawn and undrawn portions of the revolving credit facility. At June 30, 2006, we paid facility fees at a rate of 0.15% per annum.

At June 30, 2006, there was $90.0 million outstanding on the revolving credit facility and $100.0 million outstanding on the term loan facility, which is fully collateralized by high-grade securities. There were no letters of credit outstanding as of June 30, 2006. In December 2005, we incurred $0.7 million of debt issuance costs associated with the Credit Agreement. These expenses are deferred as other non-current assets in the accompanying condensed consolidated balance sheets and will be amortized over the term of the Credit Agreement.

9. Commitments and Contingent Liabilities

Litigation We are not a party to any significant legal proceedings but are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business. Management currently believes that the ultimate resolution of these matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect upon our future financial position, operations and cash flows.

In June 2006, a DEFS customer whose plant is served by our Seabreeze pipeline notified DEFS that the filters on their amine treater were clogging. Our Seabreeze pipeline transports NGLs owned by DEFS that are delivered to the customer under the terms of a transportation agreement. The customer has sent a letter to DEFS claiming that the

NGLs delivered to their facility contained iron oxide, which clogged their filters and caused other damages to their plant facility. This incident is currently under investigation by all parties. Management does not believe the ultimate resolution of this issue will have a material adverse impact on our consolidated financial position, results of operations or cash flows.

Insurance In 2005, DEFS carried insurance coverage, which included our assets and operations, with an affiliate of Duke Energy. Beginning in 2006, DEFS elected to carry our property and excess liability insurance coverage with an affiliate of Duke Energy and an affiliate of ConocoPhillips. DEFS provides our remaining insurance coverage with a third party insurer. DEFS insurance coverage includes (1) commercial general public liability insurance for liabilities arising to third parties for bodily injury and property damage resulting from operations; (2) workers compensation liability coverage to required statutory limits; (3) automobile liability insurance for all owned, non-owned and hired vehicles covering liabilities to third parties for bodily injury and property damage; (4) excess liability insurance above the established primary limits for commercial general liability and automobile liability insurance; (5) property insurance covering the replacement value of all real and personal property damage, including damages arising from boiler and machinery breakdowns, windstorms, earthquake, flood damage and business interruption/extra expense; and (6) directors and officers insurance covering our directors and officers for acts related to our activities. All coverages are subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations. Effective July 2006, our property insurance deductibles declined from $5.0 million to $0.2 million per occurrence. DEFS also maintains excess liability insurance coverage above the established primary limits for commercial general liability and automobile liability insurance. The cost of our insurance coverages increased significantly over the past year reflecting the adverse conditions of the property insurance markets.

A portion of the insurance costs described above are allocated by DEFS to us through the allocation methodology described in Note 7 of the annual report on Form 10-K for the year ended December 31, 2005.

Environmental The operation of pipelines, plants and other facilities for gathering, transporting, processing, treating, or storing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Indemnification DEFS has indemnified us for three years after the closing of our initial public offering against certain potential environmental claims, losses and expenses associated with the operation of the assets and occurring before the closing of our initial public offering, on December 7, 2005. DEFS maximum liability for this indemnification obligation is $15.0 million and DEFS does not have any obligation under this indemnification until our aggregate losses exceed $250,000. DEFS has no indemnification obligations with respect to environmental claims made as a result of additions to or modifications of environmental laws promulgated after the closing date of our initial public offering. We have agreed to indemnify DEFS against environmental liabilities related to our assets to the extent DEFS is not required to indemnify us.

Additionally, DEFS will indemnify us for three years after the closing for losses attributable to title defects, certain retained assets and liabilities (including preclosing legal actions relating to contributed assets) and income taxes attributable to pre-closing operations. We will indemnify DEFS for all losses attributable to the postclosing operations of the assets contributed to us, to the extent not subject to DEFS indemnification obligations. In addition, DEFS has agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions required to be made by us to Black Lake associated with any repairs to the Black Lake pipeline that are determined to be necessary as a result of the currently ongoing pipeline integrity testing occurring from 2005 through 2007. DEFS has also agreed to indemnify us for up to $4.0 million of the costs associated with any repairs to the Seabreeze pipeline that are determined to be necessary as a result of the scheduled pipeline integrity testing occurring in 2006 and 2007.

10. Equity-Based Compensation

Performance Units During the quarter ended June 30, 2006, we granted 40,560 Performance Units to certain employees. Performance Units generally cliff vest at the end of a three year performance period. The number of Performance Units which will ultimately vest range from 0 to 60,840 depending on the achievement of specified performance targets over a three year period ending on December 31, 2008. The final performance payout is determined by the Compensation Committee of our board of directors. Each Performance Unit includes a distribution equivalent right, which will be paid at the end of the performance period. The grant date fair value and measurement date fair value of these Performance Units was approximately $1.1 million. We recorded approximately $0.1 million of expense related to the Performance Units during the quarter ended June 30, 2006. At June 30, 2006, there was approximately $1.1 million of unrecognized compensation expense related to the Performance Units that is expected to be recognized over a weighted-average period of 2.5 years. There was no compensation expense related to Performance Units prior to the quarter ended June 30, 2006.

The estimate of Performance Units that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate and achievement of performance targets. Therefore the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our condensed consolidated statements of operations.

Phantom Units During the quarter ended March 31, 2006, we granted 35,900 Phantom Units to certain employees. Of these Phantom Units 23,900 will vest upon the three year anniversary of the grant date and the remaining 12,000 units vest ratably over three years. Each phantom unit includes a distribution equivalent right which are paid quarterly in arrears. The grant date fair value of the Phantom Units awarded during the quarter ended March 31, 2006 was approximately $0.9 million and the measurement date fair value was approximately $1.0 million. We recorded approximately $0.1 million of expense related to the Phantom Units during each of the quarters ended March 31, 2006 and June 30, 2006. At June 30, 2006 there was approximately $0.8 million of unrecognized compensation expense related to the Phantom Units that is expected to be recognized over a weighted-average period of 2.2 years. There was no compensation expense related to Phantom Units prior to January 1, 2006.

The estimate of Phantom Units that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate. Therefore the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our condensed consolidated statements of operations.

We intend to settle the Performance Units and Phantom Units, or Awards, which are accounted for as liability awards, in cash upon vesting. Compensation expense is recognized ratably over each vesting period, and will be remeasured quarterly for all Awards outstanding until the units are vested. The fair value of all Awards is determined based on the closing price of DCP Midstream Partners common units at each measurement date. During both the three and six months ended June 30, 2006, no awards were forfeited, vested or settled.

11. Business Segments

Our operations are located in the United States and are organized into two reporting segments: (1) Natural Gas Services; and (2) NGL Logistics.

Natural Gas Services The Natural Gas Services segment consists of the North Louisiana system assets, an integrated gas gathering, compression, treating, processing, and transportation system located in northern Louisiana and southern Arkansas that includes the Minden and Ada natural gas processing plants and gathering systems and the PELICO intrastate natural gas gathering and transportation pipeline.

NGL Logistics The NGL Logistics segment consists of the Seabreeze NGL transportation pipeline located along the Gulf Coast area of southeastern Texas and an equity interest in the Black Lake FERC-regulated interstate NGL pipeline located in northern Louisiana and southeastern Texas.

These segments are monitored separately by management for performance against its internal forecast and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. Gross margin is a performance measure utilized by management to monitor the business of each segment. The accounting policies for the segments are the same as those described in Note 2.

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The following tables set forth our segment information.

Three months ended June 30, 2006 ($ in millions):

	Natural Gas Services	NGL Logistics	Other(b)	Total
Total operating revenues	$ 93.6	$ 1.4	$	$ 95.0
Gross margin (a)	$ 18.2	$ 1.1	$	$ 19.3
Operating and maintenance expense	(2.9)	(0.1)		(3.0)
Depreciation and amortization expense	(2.7)	(0.2)		(2.9)
General and administrative expense			(2.2)	(2.2)
General and administrative expense affiliates			(1.4)	(1.4)
Earnings from equity method investment		0.1		0.1
Interest income			1.5	1.5
Interest expense			(2.6)	(2.6)
Net income (loss)	$ 12.6	$ 0.9	$ (4.7)	$ 8.8
Capital expenditures	$ 2.4	$ 1.0	$	$ 3.4

Three months ended June 30, 2005 ($ in millions):

	Natural Gas Services	NGL Logistics	Other(b)	Total
Total operating revenues	$ 108.0	$ 42.2	$	$ 150.2
Gross margin (a)	$ 14.3	$ 1.1	$	$ 15.4
Operating and maintenance expense	(2.9)			(2.9)
Depreciation and amortization expense	(2.7)	(0.2)		(2.9)
General and administrative expense affiliates			(2.0)	(2.0)
Earnings from equity method investment		0.1		0.1
Net income (loss)	$ 8.7	$ 1.0	$ (2.0)	$ 7.7
Capital expenditures	$ 1.6	$	$	$ 1.6

Six months ended June 30, 2006 ($ in millions):

	Natural Gas Services	NGL Logistics	Other(b)	Total
Total operating revenues	$ 212.4	$ 2.6	$	$ 215.0
Gross margin (a)	$ 35.2	$ 2.0	$	$ 37.2
Operating and maintenance expense	(7.0)	(0.3)		(7.3)
Depreciation and amortization expense	(5.5)	(0.4)		(5.9)
General and administrative expense			(4.9)	(4.9)
General and administrative expense affiliates			(2.8)	(2.8)
Earnings from equity method investment		0.1		0.1
Interest income			3.0	3.0

Interest expense			(5.2)	(5.2)
Net income (loss)	$ 22.7	$ 1.4	$ (9.9)	$ 14.2
Capital expenditures	$ 5.9	$ 1.0	$	$ 6.9

Six months ended June 30, 2005 ($ in millions):

	Natural Gas Services	NGL Logistics	Other(b)	Total
Total operating revenues	$ 196.6	$ 81.0	$	$ 277.6
Gross margin (a)	$ 28.5	$ 2.0	$	$ 30.5
Operating and maintenance expense	(6.4)	(0.1)		(6.5)
Depreciation and amortization expense	(5.5)	(0.4)		(5.9)
General and administrative expense affiliates			(3.6)	(3.6)
Earnings from equity method investment		0.3		0.3
Net income (loss)	$ 16.6	$ 1.8	$ (3.6)	$ 14.8
Capital expenditures	$ 2.9	$	$	$ 2.9

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The following table sets forth our segment assets ($ in millions):

	June 30, 2006	December 31, 2005
Segment long-term assets:		
Natural Gas Services	$ 152.5	$ 152.8
NGL Logistics	24.9	23.5
Other (c)	106.3	106.5
Total long-term assets	283.7	282.8
Current assets	61.4	124.5
Total assets	$ 345.1	$ 407.3

(a) Gross margin consists of total operating revenues less purchases of natural gas and NGLs. Gross margin is viewed as a non-Generally Accepted Accounting Principles, or non-GAAP, measure under the rules of the Securities and Exchange Commission, or SEC, but is included as a supplemental disclosure because it is a primary performance measure used by management as it represents the results of product sales versus product purchases. As an indicator of our operating performance, gross margin should not be considered an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP. Our gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner.

(b) Other consists of general and administrative expense, interest income and interest expense.

(c) Other long-term assets not allocable to segments consist of restricted investments, unrealized gains on non-trading derivative and hedging transactions and other non-current assets.

12. Income Taxes

We are structured as a master limited partnership which is a pass-through entity for U.S. income tax purposes. In May 2006, the State of Texas enacted a new margin-based franchise tax into law that replaces the existing franchise tax. This new tax is commonly referred to as the Texas margin tax. Corporations, limited partnerships, limited liability companies, limited liability partnerships and joint ventures are examples of the types of entities that are subject to the new tax. The tax is considered an income tax for purposes of adjustments to the deferred tax liability. The tax is determined by applying a tax rate to a base that considers both revenues and expenses. The Texas margin tax becomes effective for franchise tax reports due on or after January 1, 2008. The 2008 tax will be based on revenues earned during the 2007 fiscal year.

The Texas margin tax is assessed at 1% of taxable margin apportioned to Texas. We have computed taxable margin as the total revenue less cost of goods sold. The deferred tax liabilities associated with the Texas margin tax were insignificant.

13. Subsequent Events

On July 27, 2006, the board of directors of DCP Midstream Partners general partner declared a quarterly distribution of $0.38 per unit, payable on August 14, 2006 to unitholders of record on August 4, 2006.

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

The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our condensed consolidated financial statements and notes included elsewhere in this Form 10-Q and in our annual report on Form 10-K for the year ended December 31, 2005. We refer to the assets, liabilities and operations contributed to us by Duke Energy Field Services, LLC and its wholly-owned subsidiaries upon the closing of our initial public offering as DCP Midstream Partners Predecessor.

Overview

We are a Delaware limited partnership recently formed by Duke Energy Field Services, LLC, or DEFS, to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We operate two business segments:

- our Natural Gas Services segment, which consists of our North Louisiana natural gas gathering, processing and transportation system; and

- our NGL Logistics segment, which consists of our interests in two NGL pipelines.

The historical financial statements of DCP Midstream Partners Predecessor included in this quarterly report and discussed elsewhere herein include DCP Midstream Partners Predecessor s 50% ownership interest in Black Lake Pipe Line Company, or Black Lake. However, effective December 7, 2005, DEFS retained a 5% interest and we own a 45% interest in Black Lake.

Factors That Significantly Affect Our Results

The results of operations for our Natural Gas Services segment are impacted by increases and decreases in the volume of natural gas that we gather and transport through our systems, which we refer to as throughput volume. Throughput volumes and capacity utilization rates generally are driven by wellhead production and our competitive position on a regional basis and more broadly by demand for natural gas, NGLs and condensate.

Our results of operations for our Natural Gas Services segment are also impacted by the fees we receive and the margins we generate. Our processing contractual arrangements can have a significant impact on our profitability. Because of the volatility of the prices for natural gas, NGLs and condensate, as of January 1, 2006 we have hedged approximately 80% of our commodity price risk associated with our gathering and processing arrangements through 2010 with natural gas and crude oil swaps, and as of June 30, 2006, we have hedged approximately 60% of our currently anticipated 2011 condensate price risk with crude oil swaps. With these swaps, we have substantially reduced our exposure to commodity price movements with respect to those volumes under these types of contractual arrangements for this period. For additional information regarding our hedging activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies in our annual report on Form 10-K for the year ended December 31, 2005. Actual contract terms will be based upon a variety of factors, including natural gas quality, geographic location, the competitive commodity and pricing environment at the time the contract is executed and customer requirements. Our gathering and processing contract mix and, accordingly, our exposure to natural gas, NGL and condensate prices, may change as a result of producer preferences, our expansion in regions where some types of contracts are more common and other market factors.

Our results of operations for our NGL Logistics segment are impacted by the throughput volumes of the NGLs we transport on our two NGL pipelines. Both of these NGL pipelines transport NGLs exclusively on a fee basis.

Upon the closing of our initial public offering, DEFS contributed to us the assets, liabilities and operations reflected in the historical financial statements other than the accounts receivable of DCP Midstream Partners Predecessor, certain liabilities and a 5% interest in Black Lake, which were not contributed to us. The historical financial statements of DCP Midstream Partners Predecessor do not give effect to various items that affected our results of operations and liquidity following the closing of our initial public offering, including the items described below:

- the indebtedness we incurred at the closing of our initial public offering increased our interest expense;

we have entered into long-term hedging arrangements for approximately 80% of our expected natural gas, NGL and condensate commodity price risk relating to our gathering and processing arrangements through 2010, and

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approximately 60% of our expected condensate commodity price risk relating to our gathering and processing arrangements in 2011; and

we anticipate incurring approximately $9.5 million of general and administrative expense during the year ending December 31, 2006 relating to operating as a separate publicly held limited partnership, some of which will be allocated to us by DEFS. These public limited partnership expenses include compensation and benefit expenses of the personnel who provide direct support to our operations, costs associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, costs associated with the Sarbanes-Oxley Act of 2002, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and director compensation.

As a result of pipeline integrity testing scheduled during 2006, it is reasonably possible that we may experience lower volumes and increased operating costs on the Seabreeze pipeline. The Black Lake pipeline is currently experiencing increased operating costs due to pipeline integrity testing that commenced in 2005 and will continue into 2007. We expect that our results of operations related to our non-controlling interest in Black Lake will benefit in 2007 from the completion of this pipeline integrity testing, although it is possible that the integrity testing will result in the need for pipeline repairs, in which case the operations of this pipeline may be interrupted while the repairs are being made. DEFS has agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions required to be made by us to Black Lake associated with repairing the Black Lake pipeline that are determined to be necessary as a result of the pipeline integrity testing and up to $4.0 million of the costs associated with any repairs to the Seabreeze pipeline that are determined to be necessary as a result of the pipeline integrity testing.

Finally, we intend to make cash distributions to our unitholders and our general partner. Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect that we will rely upon external financing sources, including other debt and common unit issuances, to fund our acquisition and expansion capital expenditures, as well as our working capital needs.

Recent Events

In February 2006, we announced plans to construct a new 37-mile NGL pipeline to connect a DEFS gas processing plant to the Seabreeze pipeline for a cost of approximately $12 million. The project is estimated to be completed during the fourth quarter of 2006 and is supported by a 10-year NGL product dedication by DEFS. Volumes from DEFS are estimated to be approximately 5,300 barrels per day, or Bbls/d.

In March 2006, we announced that we had entered into agreements with ConocoPhillips to expand the current gathering and transportation services relationship between us. The new agreements will add acreage and extend the terms of the existing dedication through 2011. Upon execution of a successful ConocoPhillips drilling program, approximately 20 to 40 new wells may be added to our system in 2006 with additional volumes possible over the next three years.

In the second quarter of 2006, we amended our Omnibus Agreement with DEFS in which we receive certain general and administrative services from DEFS for an annual fee of $4.8 million through 2008. The amendment clarifies that the annual fee of $4.8 million under the agreement is fixed at such amount, subject to annual increases in the consumer price index and increases in connection with expansion of our operations through the acquisition or construction of new assets or businesses.

Effective December 2005, we entered into a contract with a subsidiary of DEFS that provides that DEFS will purchase natural gas and transport it to the PELICO system where we will buy the gas from DEFS at its weighted average cost delivered to the PELICO system plus a contractually agreed to marketing fee and other related adjustments. In addition, for a significant portion of the gas that we sell out of our PELICO system, DEFS will purchase that natural gas from us and transport it to a sales point at a price equal to its net weighted average sales price less a contractually agreed to marketing fee and other related adjustments.

The above agreement was amended and restated effective February 2006. The revised agreement requires that DEFS supply PELICO s system requirements that exceed its on-system supply. Accordingly, DEFS purchases natural gas and transports it to our PELICO system where we buy the gas from DEFS at the actual acquisition cost plus transportation service charges incurred. If our PELICO system has volumes in excess of the on-system demand, DEFS will purchase the excess natural gas from us and transport it to sales points at an index based price less a contractually agreed to marketing fee. In addition, DEFS may purchase other excess natural gas volumes at certain PELICO outlets for a price that equals the original PELICO purchase price from

DEFS plus a portion of the index differential between upstream sources to certain downstream indices with a maximum differential and a minimum differential plus a fixed fuel charge and other related adjustments.

On July 27, 2006, the board of directors of DCP Midstream Partners general partner declared a quarterly distribution of $0.38 per unit, payable on August 14, 2006 to unitholders of record on August 4, 2006.

In the second quarter of 2006, we entered into a letter agreement with DEFS whereby DEFS will make capital contributions to us to reimburse for capital projects which were forecasted to be completed prior to our initial public offering, but were not completed by that date. Pursuant to the letter agreement, DEFS made capital contributions to us in the second quarter of 2006 of approximately $3.2 million to reimburse us for the capital costs we incurred in the first and second quarters of 2006 for these capital projects. This amount is comprised of $1.0 million in maintenance capital and $2.2 million in growth capital. Included in our condensed consolidated balance sheet as of June 30, 2006 as accounts receivable affiliates is approximately $0.1 million from DEFS for reimbursable capital costs. DEFS will make additional capital contributions to us in the future until all these projects have been completed.

Our Operations

We manage our business and analyze and report our results of operations on a segment basis. Our operations are divided into our Natural Gas Services segment and our NGL Logistics segment.

Natural Gas Services Segment

Results of operations from our Natural Gas Services segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, transported and sold through our gathering, processing and pipeline systems; the volumes of NGLs and condensate sold; and the level of our realized natural gas, NGL and condensate prices. We generate our revenues and our gross margins for our Natural Gas Services segment principally under the following types of contractual arrangements:

Fee-based arrangements. Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compressing, treating, processing or transporting natural gas. Our fee-based arrangements include natural gas purchase arrangements pursuant to which we purchase natural gas at the wellhead or other receipt points at an index related price at the delivery point less a specified amount, which specified amount is generally the same as the transportation fees we would otherwise charge for transportation of natural gas from the wellhead location to the delivery point. Revenues associated with these arrangements may be included as sales of natural gas, NGLs and condensate or transportation and processing services. The revenue we earn is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices. To the extent a sustained decline in commodity prices results in a decline in volumes, however, our revenues from these arrangements would be reduced.

Percentage-of-proceeds arrangements. Under percentage-of-proceeds arrangements, we generally purchase natural gas from producers at the wellhead, transport the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and NGLs at index prices based on published index market prices. We remit to the producers either an agreed upon percentage of the actual proceeds that we receive from our sales of the residue natural gas and NGLs or an agreed upon percentage of the proceeds based on index related prices for the natural gas and the NGLs, regardless of the actual amount of the sales proceeds we receive. Under these types of arrangements, our revenues correlate directly with the price of natural gas and NGLs.

As of January 1, 2006, we have hedged approximately 80% of our currently anticipated natural gas and NGL commodity price risk associated with our percentage-of-proceeds arrangements through 2010 with natural gas and crude oil swaps. With these swaps, we expect our exposure to commodity price movements to be substantially reduced. Additionally, as part of our gathering operations, we recover and sell condensate. The margins we earn from condensate sales are directly correlated with crude oil prices. As of January 1, 2006, we have hedged approximately 80% of our currently anticipated condensate price risk through 2010 with crude oil swaps. As of June 30, 2006, we have hedged approximately 60% of our currently anticipated condensate price risk during 2011 with crude oil swaps. For additional information regarding our hedging activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies in our annual report on Form 10-K for the year ended

December 31, 2005.

We also purchase a small portion of our natural gas under percentage-of-index arrangements. Under percentage-of-index arrangements, we purchase natural gas from the producers at the wellhead at a price that is either at a fixed percentage of the index price for the natural gas that they produce or at an index based price less a fixed fee to gather, compress, treat and/or process their natural gas. We then gather, compress, treat and/or process the natural gas and then sell the residue natural gas and NGLs at index related prices. Under these types of arrangements, our cost to purchase the natural gas from the producer is based on the price of natural gas. As a result, our gross margin under these arrangements increases as the price of NGLs increases relative to the price of natural gas, and our gross margin under these arrangements decreases as the price of natural gas increases relative to the price of NGLs.

The natural gas supply for the gathering pipelines and processing plants in our North Louisiana system is derived primarily from natural gas wells located in five parishes in northern Louisiana. The PELICO system also receives natural gas produced in east Texas through its interconnect with other pipelines that transport natural gas from east Texas into western Louisiana. This five parish area has experienced significant levels of drilling activity, providing us with opportunities to access newly developed natural gas supplies. Our primary suppliers of natural gas to the North Louisiana system are Anadarko Petroleum Corporation and ConocoPhillips (one of our affiliates), which collectively represented approximately 64% of the 303 MMcf/d of natural gas supplied to this system during the six months ended June 30, 2006. We actively seek new supplies of natural gas, both to offset natural declines in the production from connected wells and to increase throughput volume. We obtain new natural gas supplies in our operating areas by contracting for production from new wells, connecting new wells drilled on dedicated acreage, or by obtaining natural gas that has been released from other gathering systems.

We sell natural gas to marketing affiliates of natural gas pipelines, marketing affiliates of integrated oil companies, marketing affiliates of DEFS, national wholesale marketers, industrial end-users and gas-fired power plants. We typically sell natural gas under market index related pricing terms. In addition, under our merchant arrangements, we use a subsidiary of DEFS as our agent to purchase natural gas from third parties at pipeline interconnect points, as well as residue gas from our Minden and Ada processing plants, and then resell the aggregated natural gas to third parties. We also have entered into a contractual arrangement with a subsidiary of DEFS that requires that DEFS supply PELICO s system requirements that exceed its on-system supply. Accordingly, DEFS purchases natural gas and transports it to our PELICO system where we buy the gas from DEFS at the actual acquisition cost plus transportation service charges incurred. If our PELICO system has volumes in excess of the on-system demand, DEFS will purchase the excess natural gas from us and transport it to sales points at an index based price less a contractually agreed to marketing fee. In addition, DEFS may purchase other excess natural gas volumes at certain PELICO outlets for a price that equals the original PELICO purchase price from DEFS plus a portion of the index differential between upstream sources to certain downstream indices with a maximum differential and a minimum differential plus a fixed fuel charge and other related adjustments. To the extent possible, we match the pricing of our supply portfolio to our sales portfolio in order to lock in value and reduce our overall commodity price risk. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. As a service to our customers, we may enter into physical fixed price natural gas purchases and sales, utilizing financial derivatives to swap this fixed price risk back to market index. We account for such a physical fixed price transaction and the related financial derivative as a fair value hedge. We occasionally will enter into financial derivatives to lock in price differentials across the PELICO system to maximize the value of pipeline capacity. These financial derivatives are accounted for using mark-to-market accounting. We also gather, process and transport natural gas under fee-based transportation contracts.

The NGLs extracted from the natural gas at the Minden processing plant are sold at market index prices to an affiliate of DEFS and transported to the Mont Belvieu hub via the Black Lake pipeline. The NGLs extracted from the natural gas at the Ada processing plant are sold at market index prices to third parties and are delivered to the third parties trucks at the tailgate of the plant.

NGL Logistics Segment

Historically, we have gathered and transported NGLs either under fee-based transportation contracts or through purchasing the NGLs at the inlet of the pipeline and selling the NGLs at the outlet. In conjunction with our formation, we entered into a contractual arrangement with DEFS that requires DEFS to purchase the NGLs that were historically purchased by us, and to pay us to transport the NGLs pursuant to a fee-based rate that is applied to the volumes transported. We entered into this fee-based contractual arrangement with the objective of generating approximately the same operating income per barrel transported that we realized when we were the purchaser and seller of NGLs.

Our pipelines provide transportation services to customers on a fee basis. Therefore, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers. We will not take title to the products transported on our NGL pipelines; rather, the shipper retains title and the associated commodity price risk. For the Seabreeze pipeline, we are responsible for any line loss or gain in NGLs. For the Black Lake pipeline, any line loss or gain in NGLs is allocated to the shipper. The volumes of NGLs transported on our pipelines are dependent on the level of production of NGLs from processing plants connected to our NGL pipelines. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost of separating the mixed NGLs from the natural gas. As a result, we have experienced periods in the past, and will likely experience periods in the future, in which higher natural gas prices reduce the volume of natural gas processed at plants connected to our NGL pipelines and, in turn, lower the NGL throughput on our assets. In the markets we serve, our pipelines are the sole pipeline facility transporting NGLs from the supply source.

How We Evaluate Our Operations

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include the following: (1) volumes, (2) gross margin, including segment gross margin, (3) operating and maintenance expense and general and administrative expense, (4) EBITDA and (5) distributable cash flow. Gross margin, segment gross margin, EBITDA and distributable cash flow measurements are non-Generally Accepted Accounting Principles, or non-GAAP, financial measures.

Volumes. We view throughput volumes on our North Louisiana system and the Seabreeze and Black Lake pipelines as an important factor affecting our profitability. We gather and transport some of the natural gas and NGLs under fee-based transportation contracts. Revenue from these contracts is derived by applying the rates stipulated to the volumes transported. Pipeline throughput volumes from existing wells connected to our pipelines will naturally decline over time as wells deplete. Accordingly, to maintain or to increase throughput levels on these pipelines and the utilization rate of the North Louisiana system s natural gas processing plants, we must continually obtain new supplies of natural gas and NGLs. Our ability to maintain existing supplies of natural gas and NGLs and obtain new supplies are impacted by (1) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our pipelines and (2) our ability to compete for volumes from successful new wells in other areas. The throughput volumes of NGLs on our Seabreeze pipeline and the Black Lake pipeline are substantially dependent upon the quantities of NGLs produced at our processing plants as well as NGLs produced at other processing plants that have pipeline connections with the NGL pipelines. We regularly monitor producer activity in the areas served by the North Louisiana system and the Seabreeze and Black Lake pipelines and pursue opportunities to connect new supply to these pipelines.

Gross Margin. We view our gross margin as an important performance measure of the core profitability of our operations. We review our gross margin monthly for consistency and trend analysis.

We define gross margin as total operating revenues less purchases of natural gas and NGLs, and we define segment gross margin for each segment as total operating revenues for that segment less purchases of natural gas and NGLs for that segment. Our gross margin equals the sum of our segment gross margins. Gross margin is included as a supplemental disclosure because it is a primary performance measure used by management as it represents the results of product sales and purchases, a key component of our operations. As an indicator of our operating performance, gross margin should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP.

With respect to our Natural Gas Services segment, we calculate our gross margin as our total operating revenue for this segment less purchases of natural gas and NGLs. Operating revenue consists of sales of natural gas, NGLs and condensate resulting from our gathering, compression, treating, processing and transportation activities, fees associated with the gathering of natural gas, and any gains and losses realized from our non-trading derivative activity related to our natural gas asset-based marketing. Purchases include the cost of natural gas and NGLs purchased by us. Our gross margin is impacted by our contract portfolio. We purchase the wellhead natural gas from the producers under fee-based arrangements, percentage-of-proceeds arrangements or percentage-of-index arrangements. Our gross margin generated from percentage-of-proceeds gathering and processing contracts is directly correlated to the price of natural gas and NGLs. Under percentage-of-index arrangements, our gross margin is adversely affected when the price of NGLs falls in relation to the price of natural gas. Generally, our contract structure allows for us to allocate fuel costs and other measurement losses to the producer or shipper and, therefore, does not

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impact gross margin. Additionally, as part of our gathering operations, we recover and sell condensate. The margins we earn from condensate sales are directly correlated with crude oil prices.

Our gross margin and segment gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin and segment gross margin in the same manner.

Reconciliation of Non-GAAP Measures

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	($ in millions)			
Reconciliation of net income to gross margin:				
Net income	$ 8.8	$ 7.7	$ 14.2	$ 14.8
Less:				
Interest income	1.5		3.0	
Earnings from equity method investment	0.1	0.1	0.1	0.3
Add:				
Interest expense	2.6		5.2	
Operating and maintenance expense	3.0	2.9	7.3	6.5
Depreciation and amortization expense	2.9	2.9	5.9	5.9
General and administrative expense	3.6	2.0	7.7	3.6
Gross margin	$ 19.3	$ 15.4	$ 37.2	$ 30.5
Reconciliation of segment net income to segment gross margin:				
Natural Gas Services segment:				
Segment net income	$ 12.6	$ 8.7	$ 22.7	$ 16.6
Add:				
Depreciation and amortization expense	2.7	2.7	5.5	5.5
Operating and maintenance expense	2.9	2.9	7.0	6.4
Segment gross margin	$ 18.2	$ 14.3	$ 35.2	$ 28.5
NGL Logistics segment:				
Segment net income	$ 0.9	$ 1.0	$ 1.4	$ 1.8
Add:				
Depreciation and amortization expense	0.2	0.2	0.4	0.4
Operating and maintenance expense	0.1		0.3	0.1
Less:				
Earnings from equity method investment	0.1	0.1	0.1	0.3
Segment gross margin	$ 1.1	$ 1.1	$ 2.0	$ 2.0

Operating and Maintenance Expense and General and Administrative Expense. Operating and maintenance expenses are costs associated with the operation of a specific asset. Direct labor, ad valorem taxes, repairs and maintenance, utilities and contract services comprise the most significant portion of our operating and maintenance expense. These expenses are relatively independent of the volumes through our systems but may fluctuate slightly depending on the activities performed during a specific period.

A substantial amount of our general and administrative expense is incurred through DEFS. For the three and six months ended June 30, 2006, our general and administrative expenses were $3.6 million and $7.7 million, respectively. Under our Omnibus Agreement with DEFS, as amended, we will pay DEFS $4.8 million annually for 2006, for the provision by DEFS or its affiliates of various general and administrative services to us. For 2007 and 2008, the fee will be increased by the percentage increase in the consumer price index for the applicable year. In addition, our general partner will have the right to agree to further increases in connection with expansions of our operations through the acquisition or construction of new assets or businesses with the concurrence of the special committee of our board of directors. We also reimburse DEFS for our allocable share of insurance expenses related to our businesses and properties as well as insurance expenses related to director and officer liability coverage.

We expect that our allocable share of these insurance expenses will be approximately $1.4 million in 2006. These insurance expenses were $0.3 million and $0.7 million for the three and six months ended June 30, 2006, respectively.

We anticipate incurring approximately $9.5 million of general and administrative expense during the year ending December 31, 2006 related to operating as a separate publicly held limited partnership, some of which will be allocated to us by DEFS. These public limited partnership expenses are related to compensation and benefit expenses of the personnel who provide direct support to our operations. Also included in the public limited partnership expenses are expenses associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, costs associated with the Sarbanes-Oxley Act of 2002, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and director compensation.

EBITDA and Distributable Cash Flow. We define EBITDA as net income less interest income plus interest expense and depreciation and amortization expense. EBITDA is used as a supplemental liquidity measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness, make cash distributions to our unitholders and general partner and finance maintenance capital expenditures. EBITDA is also a financial measurement that is reported to our lenders and used as a gauge for compliance with our financial covenants under our credit facility, which requires us to maintain 1) a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the credit agreement) of not more than 4.75 to 1.0 and on a temporary basis for not more than three consecutive quarters following the consummation of asset acquisitions in the midstream energy business, not more than 5.25 to 1.0; and 2) an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, in each case as is defined by the credit agreement) of greater than or equal to 3.0 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination. Our EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate EBITDA in the same manner.

EBITDA is also used as a supplemental performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess:

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to those of other companies in the midstream energy industry, without regard to financing methods or capital structure; and
- viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

EBITDA should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP as measures of operating performance, liquidity or ability to service debt obligations.

We define distributable cash flow as EBITDA, plus interest income, less interest expense, maintenance capital expenditures, net of reimbursable projects, earnings from equity method investment and adjustments for non-cash hedge ineffectiveness. In the first six months of 2006, we also adjusted for a post-closing reimbursement from DEFS for maintenance capital expenditures. Maintenance capital expenditures are capital expenditures made to replace partially or fully depreciated assets, to maintain the existing operating capacity of our assets and to extend their useful lives, or other capital expenditures that are incurred in maintaining existing system volumes and related cash flows. Non-cash hedge ineffectiveness refers to the ineffective portion of our cash flow hedges, which is recorded in earnings in the current period. This amount is considered to be non-cash for the purpose of computing distributable cash because settlement will not occur until future periods and will be impacted by future changes in commodity prices. Distributable cash flow is used as a supplemental financial measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and other, to assess our ability to make cash distributions to our unitholders and our general partner.

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Reconciliation of Non-GAAP Measures	**Three Months Ended June 30, 2006**	**Six Months Ended June 30, 2006**
	($ in millions)	
Reconciliation of net income to EBITDA and net cash provided by operating activities:		
Net income	$ 8.8	$ 14.2
Interest income	(1.5)	(3.0)
Interest expense	2.6	5.2
Depreciation and amortization expense	2.9	5.9
EBITDA	12.8	22.3
Interest income	1.5	3.0
Interest expense	(2.6)	(5.2)
Earnings from equity method investment	(0.1)	(0.1)
Net changes in operating assets and liabilities	3.3	(7.9)
Other, net	(0.6)	(1.3)
Net cash provided by operating activities	$ 14.3	$ 10.8

	Three Months Ended June 30, 2005	**Six Months Ended June 30, 2005**
	($ in millions)	
Net income	$ 7.7	$ 14.8
Depreciation and amortization	2.9	5.9
EBITDA	10.6	20.7
Earnings from equity method investment	(0.1)	(0.3)
Net changes in operating assets and liabilities	(8.8)	(2.5)
Net cash provided by operating activities	$ 1.7	$ 17.9

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are described in Item 7 of our annual report on Form 10-K for the year ended December 31, 2005. The accounting policies and estimates used in preparing our interim condensed consolidated financial statements for the three and six months ended June 30, 2006 are the same as those described in our annual report on Form 10-K for the year ended December 31, 2005.

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Results of Operations

Consolidated Overview

The following table and discussion is a summary of our condensed consolidated results of operations for the three and six months ended June 30, 2006 and 2005. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	($ in millions)			
Operating revenues:				
Sales of natural gas, NGLs and condensate	$ 88.1	$ 144.7	$ 201.6	$ 266.8
Transportation and processing services	6.9	5.5	13.4	10.8
Total operating revenues	95.0	150.2	215.0	277.6
Purchases of natural gas and NGLs	75.7	134.8	177.8	247.1
Gross margin (a)	19.3	15.4	37.2	30.5
Operating and maintenance expense	(3.0)	(2.9)	(7.3)	(6.5)
General and administrative expense	(3.6)	(2.0)	(7.7)	(3.6)
Earnings from equity method investment (b)	0.1	0.1	0.1	0.3
EBITDA (c)	12.8	10.6	22.3	20.7
Depreciation and amortization expense	(2.9)	(2.9)	(5.9)	(5.9)
Interest income	1.5		3.0	
Interest expense	(2.6)		(5.2)	
Net income	$ 8.8	$ 7.7	$ 14.2	$ 14.8
Segment financial and operating data:				
Natural Gas Services Segment				
Financial data:				
Segment gross margin (a)	$ 18.2	$ 14.3	$ 35.2	$ 28.5
Operating data:				
Natural gas throughput (MMcf/d)	386	340	375	330
NGL gross production (Bbls/d)	5,320	4,858	5,141	4,965
NGL Logistics Segment				
Financial data:				
Segment gross margin (a)	$ 1.1	$ 1.1	$ 2.0	$ 2.0
Operating data:				
Seabreeze throughput (Bbls/d)	19,702	14,599	19,365	14,462
Black Lake throughput (Bbls/d) (c)	4,767	5,044	4,582	5,138

(a) Gross margin consists of total operating revenues less purchases of natural gas and

NGLs and segment gross margin for each segment consists of total operating revenues for that segment less purchases of natural gas and NGLs for that segment. Please read How We Evaluate Our Operations above.

(b) Represents 50% of the throughput volumes and earnings of Black Lake for the three and six months ended June 30, 2005. Upon closing of our initial public offering on December 7, 2005, DEFS retained a 5% interest in Black Lake. We own a 45% interest in Black Lake.

(c) EBITDA consists of net income plus net interest expense and depreciation and amortization expense. Please read How We Evaluate Our Operations above.

Three Months Ended June 30, 2006 vs. Three Months Ended June 30, 2005

Total Operating Revenues Total operating revenues decreased $55.2 million, or 37%, to $95.0 million in 2006 from $150.2 million in 2005. This decrease was primarily due to the following factors:

- $41.9 million decrease primarily attributable to lower sales volume for our Seabreeze pipeline primarily due to a change in contract terms in December 2005 from a purchase and sale arrangement to a fee-based contractual transportation arrangement; and

- $14.8 million decrease attributable primarily to lower natural gas sales volumes, a decrease in natural gas prices and a change in the reporting of certain PELICO revenues from a gross presentation to a net presentation as a result of an amendment to a contract with an affiliate, offset by an increase in NGL and condensate prices and an increase in NGL sales volumes; offset by

- $1.1 million increase in transportation revenue attributable to the Seabreeze pipeline change in contract terms in December 2005 from a purchase and sale arrangement to a fee-based contractual transportation arrangement; and

- $0.4 million increase related to commodity hedging which increased operating revenues during the second quarter of 2006.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs decreased $59.1 million, or 44%, to $75.7 million in 2006 from $134.8 million in 2005. This decrease was primarily due to the following factors:

- $40.8 million decrease attributable to lower purchased volume for our Seabreeze pipeline primarily due to a change in contract terms in December 2005 from a purchase and sale arrangement to a fee-based contractual transportation arrangement; and

- $18.3 million decrease attributable to lower cost of raw natural gas supply primarily driven by lower natural gas prices and a change in the reporting of certain PELICO purchases from a gross presentation to a net presentation as a result of an amendment to a contract with an affiliate.

Gross Margin Gross margin increased $3.9 million, or 25%, to $19.3 million in 2006 from $15.4 million in 2005 primarily attributable to higher NGL and condensate prices, an increase in natural gas throughput volumes and an increase in marketing activity and throughput across our PELICO system due to atypical differences in natural gas prices at various receipt and delivery points across the system. The market conditions causing the differentials in natural gas prices may not continue in the future, nor can we assure our ability to capture upside margin if these market conditions do occur.

Operating and Maintenance Expense Operating and maintenance expense remained relatively constant at $3.0 million in 2006 and $2.9 million in 2005.

General and Administrative Expense General and administrative expense increased $1.6 million, or 80%, to $3.6 million in 2006 from $2.0 million in 2005. This increase was primarily the result of the following:

- higher public limited partnership expenses of approximately $1.1 million primarily attributable to tax return and Schedule K-1 preparation and distribution, independent auditor fees, costs associated with the Sarbanes-Oxley Act of 2002, and incremental director and officer liability insurance costs;

- higher labor, benefits and employee expenses of approximately $0.9 million; and

- higher allocated costs for insurance premiums from DEFS of approximately $0.3 million; offset by

- lower general and administrative expense primarily from DEFS of approximately $0.7 million.

Earnings from Equity Method Investment Earnings from equity method investment remained constant at $0.1 million in 2006 and 2005.

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Six Months Ended June 30, 2006 vs. Six Months Ended June 30, 2005

Total Operating Revenues Total operating revenues decreased $62.6 million, or 23%, to $215.0 million in 2006 from $277.6 million in 2005. This decrease was primarily due to the following factors:

$80.5 million decrease primarily attributable to lower sales volume for our Seabreeze pipeline primarily due to a change in contract terms in December 2005 from a purchase and sale arrangement to a fee-based contractual transportation arrangement; offset by

$15.8 million increase attributable primarily to higher commodity prices, offset by lower natural gas sales volumes and a change in the reporting of certain PELICO revenues from a gross presentation to a net presentation as a result of an amendment to a contract with an affiliate; and

$2.1 million increase in transportation revenue attributable to the Seabreeze pipeline change in contract terms in December 2005 from a purchase and sale arrangement to a fee-based contractual transportation arrangement.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs decreased $69.3 million, or 28%, to $177.8 million in 2006 from $247.1 million in 2005. This decrease was primarily due to the following factors:

$78.4 million decrease attributable to lower purchased volume for our Seabreeze pipeline primarily due to a change in contract terms in December 2005 from a purchase and sale arrangement to a fee-based contractual transportation arrangement; offset by

$9.1 million increase attributable to higher costs of raw natural gas supply driven by higher commodity prices and increased purchased volumes, offset by a change in the reporting of certain PELICO purchases from a gross presentation to a net presentation as a result of an amendment to a contract with an affiliate.

Gross Margin Gross margin increased $6.7 million, or 22%, to $37.2 million in 2006 from $30.5 million in 2005 primarily attributable to higher commodity prices and an increase in marketing activity and throughput across our PELICO system due to atypical differences in natural gas prices at various receipt and delivery points across the system. The market conditions causing the differentials in natural gas prices may not continue in the future, nor can we assure our ability to capture upside margin if these market conditions do occur.

Operating and Maintenance Expense Operating and maintenance expense increased $0.8 million, or 12%, to $7.3 million in 2006 from $6.5 million in 2005. This increase was primarily the result of higher direct labor and costs for outside services, parts and supplies for maintenance and pipeline integrity testing on our Minden gathering system.

General and Administrative Expense General and administrative expense increased $4.1 million, or 114%, to $7.7 million in 2006 from $3.6 million in 2005. This increase was primarily the result of the following:

higher public limited partnership expenses of approximately $2.3 million primarily attributable to tax return and Schedule K-1 preparation and distribution, independent auditor fees, costs associated with the Sarbanes-Oxley Act of 2002, and incremental director and officer liability insurance costs;

higher labor, benefits and employee expenses of approximately $1.9 million; and

higher allocated costs for insurance premiums from DEFS of approximately $0.7 million; offset by

lower general and administrative expense primarily from DEFS of approximately $0.8 million.

Earnings from Equity Method Investment Earnings from equity method investment decreased $0.2 million to $0.1 million in 2006 from $0.3 million in 2005. This decrease was primarily due to an increase in Black Lake operating costs as a result of pipeline integrity testing during the first quarter of 2006.

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Results of Operations   Natural Gas Services Segment

This segment consists of our North Louisiana system, which includes our PELICO system and our Minden and Ada processing plants and gathering systems.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	($ in millions)			
Operating revenues:				
Sales of natural gas, NGLs and condensate	$ 87.8	$ 102.5	$ 201.1	$ 185.8
Transportation and processing services	5.8	5.5	11.3	10.8
Total operating revenues	93.6	108.0	212.4	196.6
Purchases of natural gas and NGLs	75.4	93.7	177.2	168.1
Segment gross margin (a)	18.2	14.3	35.2	28.5
Operating and maintenance expense	(2.9)	(2.9)	(7.0)	(6.4)
Depreciation and amortization expense	(2.7)	(2.7)	(5.5)	(5.5)
Natural Gas Services segment net income	$ 12.6	$ 8.7	$ 22.7	$ 16.6
Operating data:				
Natural gas throughput (MMcf/d)	386	340	375	330
NGL gross production (Bbls/d)	5,320	4,858	5,141	4,965

(a) Segment gross margin for each segment consists of total operating revenues for that segment less purchases of natural gas and NGLs for that segment. Please read How We Evaluate Our Operations above.

Three Months Ended June 30, 2006 vs. Three Months Ended June 30, 2005

Total Operating Revenues   Total operating revenues decreased $14.4 million, or 13%, to $93.6 million in 2006 from $108.0 million in 2005. This decrease was primarily due to the following factors:

$20.1 million decrease primarily attributable to lower natural gas sales volumes and a change in the reporting of certain PELICO revenues from a gross presentation to a net presentation as a result of an amendment to a contract with an affiliate; and

$2.1 million decrease attributable to a decrease in natural gas prices; offset by

$5.8 million increase attributable to an increase in NGL and condensate prices;

$1.3 million increase attributable to an increase in NGL sales volumes;

$0.4 million increase related to commodity hedging which increased operating revenues during the second quarter of 2006; and

$0.3 million increase in transportation revenue primarily attributable to an increase in natural gas throughput.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs decreased $18.3 million, or 20%, to $75.4 million in 2006 from $93.7 million in 2005. This decrease was due to lower cost of raw natural gas supply driven by lower natural gas prices and a change in the reporting of certain PELICO purchases from a gross presentation to a net presentation as a result of an amendment to a contract with an affiliate.

Segment Gross Margin Segment gross margin increased $3.9 million, or 27%, to $18.2 million in 2006 from $14.3 million in 2005, primarily as a result of the following factors:

$3.2 million increase attributable to higher NGL and condensate prices, offset by lower natural gas prices resulting in favorable frac spreads, which are the differences between the value of the NGLs extracted from processing and the value of the Btu equivalent of the residue natural gas;

$1.0 million increase primarily attributable to an increase in natural gas throughput volumes;

$0.9 million increase attributable to an increase in marketing activity and throughput across our PELICO system due to atypical differences in natural gas prices at various receipt and delivery points across the system. The market conditions causing the differentials in natural gas prices may not continue in the future, nor can we assure our ability to capture upside margin if these market conditions do occur; and

$0.4 million increase related to commodity hedging which increased operating revenues during the second quarter of 2006; offset by

$1.6 million decrease primarily attributable to a change in contract mix.

Operating and Maintenance Expense Operating and maintenance expense remained constant at $2.9 million in both 2006 and 2005.

NGL production in 2006 increased 462 barrels per day, or 10%, to 5,320 barrels per day from 4,858 barrels per day in 2005 due primarily to higher throughput volume at our Minden processing plant. Natural gas transported and/or processed during 2006 increased 46 MMcf/d, or 14%, to 386 MMcf/d from 340 MMcf/d in 2005 primarily as a result of higher natural gas volumes transported on our PELICO system.

Six Months Ended June 30, 2006 vs. Six Months Ended June 30, 2005

Total Operating Revenues Total operating revenues increased $15.8 million, or 8%, to $212.4 million in 2006 from $196.6 million in 2005. This increase was primarily due to the following factors:

$19.2 million increase attributable to an increase in natural gas prices;

$9.8 million increase attributable to an increase in NGL and condensate prices;

$3.9 million increase primarily attributable to increased throughput across the PELICO system due to an increase in marketing activity as a result of atypical and significant differences in natural gas prices at various receipt and delivery points across the system. The market conditions causing these significant differences in the natural gas prices at various receipt and delivery points across the PELICO system are unusual and are not expected to continue in the near future. If these market conditions do occur in future periods, our ability to capture this upside may be limited;

$1.0 million increase attributable to an increase in NGL sales volumes; and

$0.5 million increase in transportation revenue primarily attributable to an increase in natural gas throughput; offset by

$18.6 million decrease primarily attributable to lower natural gas sales volumes and a change in the reporting of certain PELICO revenues from a gross presentation to a net presentation as a result of an amendment to a contract with an affiliate.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs increased $9.1 million, or 5%, to $177.2 million in 2006 from $168.1 million in 2005. This increase was primarily due to higher costs of raw natural gas supply driven by higher commodity prices and increased purchased volumes, offset by a change in the reporting of certain PELICO purchases from a gross presentation to a net presentation as a result of an amendment to a contract with an affiliate.

Segment Gross Margin Segment gross margin increased $6.7 million, or 24%, to $35.2 million in 2006 from $28.5 million in 2005, primarily as a result of the following factors:

$4.6 million increase attributable to an increase in marketing activity and throughput across our PELICO system due to atypical differences in natural gas prices at various receipt and delivery points across the system. The market conditions

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causing the differentials in natural gas prices may not continue in the future, nor can we assure our ability to capture upside margin if these market conditions do occur;

$4.5 million increase attributable to higher commodity prices and favorable frac spreads; and

$1.2 million increase primarily attributable to an increase in natural gas throughput volumes; offset by

$1.8 million decrease attributable to higher netback prices paid to the producers at Minden and Ada;

$1.1 million decrease primarily attributable to a change in contract mix; and

$0.7 million decrease attributable to lower contractual fees charged to customers related to pipeline imbalances.

Operating and Maintenance Expense Operating and maintenance expense increased $0.6 million, or 9%, to $7.0 million in 2006 from $6.4 million in 2005. This increase was primarily the result of higher direct labor and costs for outside services, parts and supplies for maintenance and pipeline integrity testing on our Minden gathering system in the second quarter of 2006.

NGL production during 2006 increased 176 barrels per day, or 4%, to 5,141 barrels per day from 4,965 barrels per day in 2005 due primarily to higher throughput volume at our Minden processing plant. Natural gas transported and/or processed during 2006 increased 45 MMcf/d, or 14%, to 375 MMcf/d from 330 MMcf/d in 2005 primarily as a result of higher natural gas volumes transported on our PELICO system.

Results of Operations NGL Logistics Segment

This segment includes our NGL transportation pipelines, which includes our Seabreeze pipeline and our interest in Black Lake.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	($ in millions)			
Operating revenues:				
Sales of NGLs	$ 0.3	$ 42.2	$ 0.5	$ 81.0
Transportation and processing services	1.1		2.1	
Total operating revenues	1.4	42.2	2.6	81.0
Purchases of NGLs	0.3	41.1	0.6	79.0
Segment gross margin (a)	1.1	1.1	2.0	2.0
Operating and maintenance expense	(0.1)		(0.3)	(0.1)
Depreciation and amortization expense	(0.2)	(0.2)	(0.4)	(0.4)
Earnings from equity method investment	0.1	0.1	0.1	0.3
NGL Logistics segment net income	$ 0.9	$ 1.0	$ 1.4	$ 1.8
Operating data:				
Seabreeze throughput (Bbls/d)	19,702	14,599	19,365	14,462
Black Lake throughput (Bbls/d) (b)	4,767	5,044	4,582	5,138

(a) Segment gross margin for each segment consists of total operating revenues for that segment less purchases of natural gas and NGLs for that segment. Please read How We Evaluate Our Operations above.

(b) Represents 50% of the throughput volume of the Black Lake pipeline during the three and six months ended June 30, 2005. Upon closing of our initial public offering on December 7, 2005, DEFS retained a 5% interest in Black Lake. We own a 45% interest in Black Lake.

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Three Months Ended June 30, 2006 vs. Three Months Ended June 30, 2005

Total Operating Revenues Total operating revenues decreased $40.8 million, or 97%, to $1.4 million in 2006 from $42.2 million in 2005. This decrease was primarily due to the following factors:

$41.9 million decrease primarily attributable to lower sales volume for our Seabreeze pipeline primarily due to a change in contract terms in December 2005 from a purchase and sale arrangement to a fee-based contractual transportation arrangement; offset by

$1.1 million increase in transportation revenue attributable to the change in contract terms in December 2005, from a purchase and sale arrangement to a fee-based contractual transportation arrangement.

Purchases of NGLs Purchases of NGLs decreased $40.8 million, or 99%, to $0.3 million in 2006 from $41.1 million in 2005 attributable to lower purchased volume due to the change in contract terms in December 2005 from a purchase and sale arrangement to a fee-based contractual transportation arrangement.

Segment Gross Margin Segment gross margin remained constant at $1.1 million in 2006 and 2005.

Earnings from Equity Method Investment Earnings from equity method investment remained constant at $0.1 million in both 2006 and 2005.

Overall, our Seabreeze pipeline experienced an increase in throughput volume of 5,103 Bbls per day during the second quarter of 2006 as a result of a temporary disruption in supply from a third-party pipeline in 2005, which was restored in June 2005.

Six Months Ended June 30, 2006 vs. Six Months Ended June 30, 2005

Total Operating Revenues Total operating revenues decreased $78.4 million, or 97%, to $2.6 million in 2006 from $81.0 million in 2005. This decrease was primarily due to the following factors:

$80.5 million decrease primarily attributable to lower sales volume for our Seabreeze pipeline primarily due to a change in contract terms in December 2005 from a purchase and sale arrangement to a fee-based contractual transportation arrangement; offset by

$2.1 million increase in transportation revenue attributable to the change in contract terms in December 2005, from a purchase and sale arrangement to a fee-based contractual transportation arrangement.

Purchases of NGLs Purchases of NGLs decreased $78.4 million, or 99%, to $0.6 million in 2006 from $79.0 million in 2005 attributable to lower purchased volume due to the change in contract terms in December 2005 from a purchase and sale arrangement to a fee-based contractual transportation arrangement.

Segment Gross Margin Segment gross margin remained constant at $2.0 million in both 2006 and 2005.

Earnings from Equity Method Investment Earnings from equity method investment decreased $0.2 million to $0.1 million in 2006 from $0.3 million in 2005. This decrease was primarily due to an increase in Black Lake operating costs as a result of pipeline integrity testing during the first quarter of 2006.

Overall, our Seabreeze pipeline experienced an increase in throughput volume of 4,903 Bbls per day during the six months ended June 30, 2006 as a result of a temporary disruption in supply from a third-party pipeline in 2005, which was restored in June 2005.

Liquidity and Capital Resources

Historically, our sources of liquidity included cash generated from operations and funding from DEFS. Our cash receipts were deposited in DEFS bank accounts and all cash disbursements were made from these accounts. Thus, historically our financial statements have reflected no cash balances. Cash transactions handled by DEFS for us were reflected in partners equity as intercompany advances between DEFS and us. Following our initial public offering, we maintain our own bank accounts, which are managed by DEFS.

We expect our sources of liquidity to include:

- cash generated from operations;
- cash distributions from Black Lake;
- borrowings under our revolving credit facility;
- cash realized from the liquidation of securities that are pledged under our term loan facility;
- issuance of additional partnership units; and
- debt offerings.

We used a portion of our retained $206.4 million from our initial public offering to: 1) purchase $100.1 million of high-grade securities, which were used as collateral to secure the term loan portion of our credit facility, 2) pay approximately $4.0 million of expenses associated with our initial public offering and related formation transactions, 3) distribute approximately $8.6 million in cash to subsidiaries of DEFS as reimbursement for capital expenditures incurred by subsidiaries of DEFS prior to our initial public offering related to assets contributed to us upon the closing of our initial public offering, which distribution was made in partial consideration of the assets contributed to us upon the closing of our initial public offering, and 4) use the remaining amount of approximately $93.7 million to fund payables and future capital expenditures (including potential acquisitions), working capital and other general partnership purposes.

We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements, long-term capital expenditure requirements and quarterly cash distributions. Our hedging program may require us to post collateral depending on commodity price movements. DEFS has issued parental guarantees for our commodity hedging transactions that span through 2010, which may reduce our requirement to post collateral.

Changes in natural gas, NGL and condensate prices and the terms of our processing arrangements have a direct impact on our generation and use of cash from operations due to their impact on net income, along with the resulting changes in working capital. As of January 1, 2006, we have hedged approximately 80% of our share of anticipated natural gas and NGL price risk associated with our percentage-of-proceeds arrangements through 2010 with natural gas and crude oil swaps. Additionally, as part of our gathering operations, we recover and sell condensate. We have hedged approximately 80% of our share of anticipated condensate price risk associated with our gathering operations through 2010 with crude oil swaps. As of June 30, 2006, we have hedged approximately 60% of our currently anticipated condensate price risk during 2011 with crude oil swaps. For additional information regarding our hedging activities, please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies in our annual report on Form 10-K for the year ended December 31, 2005.

Working Capital Working capital is the amount by which current assets exceed current liabilities. Our working capital requirements are primarily driven by changes in accounts receivable and accounts payable. These changes are impacted by changes in the prices of commodities that we buy and sell. In general, our working capital requirements increase in periods of rising commodity prices and decline in periods of falling commodity prices. However, our working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by the same commodity prices. We had working capital of $21.5 million as of June 30, 2006, compared to working capital of $31.1 million as of December 31, 2005. During these periods, the decrease in working capital was primarily due to the timing of fluctuations in accounts receivable and accounts payable as described above. We expect that our future working capital requirements will be impacted by these same factors.

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Cash flow Net cash provided by operating activities, net cash used in investing activities and net cash used in financing activities for the six months ended June 30, 2006 and 2005 were as follows:

	Six Months Ended June 30,	
	2006	2005
	($ in millions)	
Net cash provided by operating activities	$ 10.8	$ 17.9
Net cash used in investing activities	$ (7.8)	$ (2.8)
Net cash used in financing activities	$(24.9)	$(15.1)

Net Cash Provided by Operating Activities The changes in net cash provided by operating activities are attributable to our net income adjusted for non-cash charges as presented in the condensed consolidated statements of cash flows and changes in working capital as discussed above.

Net Cash Used in Investing Activities Net cash used in investing activities during the six months ended June 30, 2006 and 2005 primarily consisted of capital expenditures, which generally consisted of expenditures for construction and expansion of our infrastructure in addition to well connections and other upgrades to our existing facilities. Included in net cash used in investing activities are purchases of available-for-sale securities and proceeds from sales of available-for-sale securities, each in the amount of approximately $4.2 billion during the six months ended June 30, 2006. These purchases and sales consist of short-term and restricted investments. Short-term investments are generally available for general corporate purposes and our restricted investments secure the term loan portion of the credit facility and are to be used only for future capital or acquisition expenditures.

Net Cash Used in Financing Activities Net cash used in financing activities during the six months ended June 30, 2006 represents the payment of $20.0 million on our revolving credit facility and $0.1 million on our term loan facility and $8.0 million of distributions to our unitholders and general partner, offset by $3.2 million of contributions from DEFS. Net cash used in financing activities during the six months ended June 30, 2005 represents the pass through of our net cash flows to DEFS under its cash management program as discussed above.

Capital Requirements

The midstream energy business can be capital intensive, requiring significant investment to maintain and upgrade existing operations. In our Natural Gas Services segment, a significant portion of the cost of constructing new gathering lines to connect to our gathering system is generally paid for by the natural gas producer. In this segment, our expansion capital expenditures may include the construction of new pipelines that would facilitate greater movement of natural gas from western Louisiana and eastern Texas to the market hub that the PELICO system is connected to near Perryville, Louisiana. This hub provides access to several intrastate and interstate pipelines, including pipelines that transport natural gas to the northeastern United States.

Our capital requirements have consisted primarily of, and we anticipate will continue to consist of the following:

- maintenance capital expenditures, which are cash expenditures where we add on to or improve capital assets owned or acquire or construct new capital assets if such expenditures are made to maintain, including over the long term, our operating capacity or revenues; and

- expansion capital expenditures, which are cash expenditures for acquisitions or capital improvements (where we add on to or improve the capital assets owned, or acquire or construct new gathering lines, treating facilities, processing plants, fractionation facilities, pipelines, terminals, docks, truck racks, tankage and other storage, distribution or transportation facilities and related or similar midstream assets) in each case if such addition, improvement, acquisition or construction is made to increase our operating capacity or revenues or that of our equity interests.

Given our objective of growth through acquisitions, expansion of existing assets and other internal growth projects, we anticipate that we will continue to invest significant amounts of capital to grow and acquire assets. We actively consider a variety of assets for potential acquisitions and expansion projects.

We have budgeted maintenance capital expenditures of $2.2 million and expansion capital expenditures of $23.6 million for the year ending December 31, 2006. During the six months ended June 30, 2006, our capital expenditures totaled $6.9 million, including maintenance capital expenditures of $2.0 million and expansion capital expenditures of $4.9 million. For the six months ended June 30, 2006, we had changes in receivables and collections from DEFS and producers of maintenance capital expenditures of approximately $0.8 million. As a result, our total maintenance capital expenditures net of reimbursements are approximately $1.2 million for the six months ended June 30, 2006. We expect our maintenance capital spending net of reimbursements from DEFS and producers for the year ending December 31, 2006 to be in line with our budget.

Annual maintenance capital expenditures in 2006 are expected to be lower than 2005 as a result of the completion of a 2005 project to add and modify compression and flow lines to increase volumes at the Ada processing plant. Annual expansion capital expenditures in 2006 are expected to increase as compared to 2005 as a result of the new NGL project, for which expansion capital expenditures are expected to be approximately $12.0 million, $0.9 million of which was expended during the six months ended June 30, 2006. We expect to fund future capital expenditures with restricted investments, funds generated from our operations, borrowings under our credit facility, the issuance of additional partnership units as appropriate given market conditions and the liquidation of high-grade securities that have been pledged under our credit facility.

Description of Credit Agreement. On December 7, 2005, we entered into a 5-year credit agreement that consists of:

a $250.0 million revolving credit facility; and

a $100.1 million term loan facility.

The revolving credit facility is available for general partnership purposes, including working capital, letters of credit, capital expenditures, acquisitions and cash distributions. We had outstanding indebtedness of $90.0 million under our revolving credit facility as of June 30, 2006.

We had outstanding indebtedness of $100.0 million under the term loan facility as of June 30, 2006. Amounts repaid under the term loan facility, which consist of $0.1 million during the second quarter of 2006, may not be reborrowed. The full balance on the term loan was collateralized, as required by the credit agreement, by investments in high-grade securities as of June 30, 2006 for future use in funding capital expenditures (including potential acquisitions) and in order to reduce our cost of borrowings under the term loan facility.

We have the option of increasing the size of the revolving credit facility to $550.0 million with the consent of the issuing lenders.

Our obligations under the revolving credit facility are unsecured and the term loan facility is secured at all times by high-grade securities in an amount equal to or greater than the outstanding principal amount of the term loan. We may sell any portion of the collateral for the term loan facility at any time as long as we use the proceeds from the sale to repay term loan borrowings. Upon any prepayment of term loan borrowings, the amount of our revolving credit facility will automatically increase to the extent that the repayment of our term loan facility is made in connection with an acquisition of assets in the midstream energy business.

We may prepay all loans at any time without penalty, subject to the reimbursement of lender breakage costs in the case of prepayment of London Interbank Offered Rate, or LIBOR, borrowings. Indebtedness under the revolving credit facility bears interest, at our option, at either (1) the higher of the federal funds rate plus 0.50% or Wachovia Bank s prime rate plus an applicable margin of 0% to 0.025% based on leverage level or (2) LIBOR plus an applicable margin which ranges from 0.27% to 1.025% dependent upon the leverage level or credit rating. As of June 30, 2006, the $100.0 million term loan facility bears interest at LIBOR plus a rate per annum of 0.15%. The revolving credit facility incurs an annual facility fee of 0.08% to 0.35% depending on the applicable leverage level or debt rating. This fee is paid on drawn and undrawn portions of the revolving credit facility. At June 30, 2006 we paid facility fees at a rate of 0.15% per annum.

The credit agreement prohibits us from making distributions of available cash to unitholders if any default or event of default (as defined in the credit agreement) exists. The credit agreement requires us to maintain a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the credit agreement) of not more than 4.75 to 1.0 and on a temporary basis for not more than three consecutive quarters following the consummation of asset acquisitions in the midstream energy business of not more than 5.25 to 1.0. The credit agreement also requires us to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, in each case as is defined by the credit

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agreement) of equal or greater than 3.0 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination.

Interest rate cash flow hedge On March 14, 2006, we entered into interest rate swap agreements to modify a portion of the variable rate line of credit to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. The interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in accumulated other comprehensive (loss) income in the accompanying condensed consolidated balance sheets. Ineffective portions of changes in fair value are recognized in earnings. The agreements expire on December 7, 2010 and reprice prospectively approximately every 90 days. Under the terms of the interest rate swap agreements, we pay a fixed rate of 5.08% and receive interest payments based on 3-month LIBOR on a total notional amount of $75.0 million. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense. The agreements are with major financial institutions, which are expected to fully perform under the terms of the agreements.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of June 30, 2006, is as follows:

	Payments Due By Period				
	Total	Remainder of 2006	2007-2008	2009-2010	2011 and Thereafter
	($ in millions)				
Long-term debt (a)	$ 190.0	$	$	$ 190.0	$
Operating lease obligations	0.2		0.1	0.1	
Purchase obligations (b)	2.3	2.3			
Other long-term liabilities (c)	0.4		0.1		0.3
Total	$ 192.9	$ 2.3	$ 0.2	$ 190.1	$ 0.3

(a) Interest payments on long-term debt are not included as they are based on floating interest rates and we cannot determine with accuracy the repayment date or the amount of the interest payment.

(b) Purchase obligations total $2.3 million of various non-cancelable commitments for capital projects expected to be completed in the remainder of 2006. Purchase obligations exclude $29.5 million of accounts payable, $0.6 million of accrued interest payable and $6.4 million of other current liabilities recognized on the June 30, 2006 condensed consolidated balance sheet. Purchase obligations also exclude $3.4 million of current and $7.8 million of long-term unrealized losses on non-trading derivative and hedging transactions included on the June 30, 2006 condensed consolidated balance sheet. These amounts represent the current fair value of various derivative contracts and do not represent future cash purchase obligations.

These contracts may be settled financially at the difference between the future market price and the contractual price and may result in cash payments or cash receipts in the future, but generally do not require delivery of physical quantities. In addition, many of our gas purchase contracts include short- and long-term commitments to purchase produced gas at market prices. These contracts, which have no minimum quantities, are excluded from the table.

(c) Other long-term liabilities include $0.3 million of asset retirement obligations and $0.1 million of environmental reserves recognized on the June 30, 2006 condensed consolidated balance sheet.

Recent Accounting Pronouncements

SFAS 154, Accounting Changes and Error Corrections In June 2005, the FASB issued SFAS 154, a replacement of APB Opinion No. 20, *Accounting Changes,* and FASB Statement No. 3, *Reporting Accounting*

Changes in Interim Financial Statements. Among other changes, SFAS 154 requires that a voluntary change in accounting principle be applied retrospectively with all prior period financial statements presented on the new accounting principle, unless it is impracticable to do so. SFAS 154 also provides that (1) a change in method of depreciating or amortizing a long-lived nonfinancial asset be accounted for as a change in estimate (prospectively) that was effected by a change in accounting principle, and (2) carried forward without change the guidance within Opinion 20 for reporting the correction of an error in previously issued financial statements and a change in accounting estimate. The new standard is effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005. SFAS 154 did not have a material impact on our consolidated results of operations, cash flows or financial position.

Emerging Issues Task Force Issue No. 04-13, or EITF 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty. In September 2005, the FASB ratified the EITF s consensus on Issue 04-13, which requires an entity to treat sales and purchases of inventory between the entity and the same counterparty as one transaction for purposes of applying APB Opinion No. 29, or APB 29, when such transactions are entered into in contemplation of each other. When such transactions are legally contingent on each other, they are considered to have been entered into in contemplation of each other. The EITF also agreed on other factors that should be considered in determining whether transactions have been entered into in contemplation of each other. EITF 04-13 is to be applied to new arrangements that we enter into in reporting periods beginning after March 15, 2006. The adoption of EITF 04-13 did not have a material impact on our consolidated results of operations, cash flows or financial position.

Item 3. *Quantitative and Qualitative Disclosures about Market Risk*

For an in-depth discussion of our market risks, see Quantitative and Qualitative Disclosures about Market Risk in our annual report on Form 10-K for the year ended December 31, 2005.

Risk Policies

Management has established comprehensive risk management policies and a risk management committee to monitor and manage market risks associated with commodity prices. Our risk management committee is composed of senior executives who receive regular briefings on positions and exposures, credit exposures and overall risk management in the context of market activities. The committee is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. The Risk Management Policy was adopted and the committee was formed effective with our board of directors approval effective February 8, 2006. Prior to the formation of the committee, we were utilizing DEFS risk management policies, procedures and risk management committee.

Interest Rate Risk

The interest rate markets have recently experienced 50-year record lows. As the overall economy strengthens, it is likely that monetary policy will continue to tighten further, resulting in higher interest rates to counter possible inflation. Interest rates on future credit facility draws and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Although this could limit our ability to raise funds in the debt capital markets, we expect to remain competitive with respect to acquisitions and capital projects, as our competitors would face similar circumstances. Based on the unhedged borrowings under our revolving credit facility as of June 30, 2006 of $15.0 million, a 0.5% movement in the base rate or LIBOR rate would result in an approximately $0.1 million annualized increase or decrease in interest expense.

On March 14, 2006, we entered into interest rate swap agreements to modify a portion of the variable rate line of credit to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. The agreements expire on December 7, 2010 and reprice prospectively approximately every 90 days. Under the terms of the interest rate swap agreements, we pay a fixed rate and receive interest payments based on 3-month LIBOR on a total notional amount of $75 million. The agreements are with major financial institutions, which are expected to fully perform under the terms of the agreements.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of our gathering, processing and sales activities. We employ established policies and procedures to manage our risks associated with these market fluctuations using various commodity derivatives, including forward contracts, swaps and futures. For the year ending December 31, 2006, we expect that a $1.00 per MMBtu decrease in the price of natural gas, a $0.10 per gallon decrease in NGL prices and a $5.00 per barrel decrease in condensate prices would decrease our gross margin by approximately $0.2 million, $0.3 million and $0.3 million, respectively. These sensitivities include the effect of our hedging strategies executed in September 2005. Please read Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk Hedging Strategies in our annual report on Form 10-K for the year ended December 31, 2005 for more information about these hedging strategies and our commodity price risk.

As of June 30, 2006, we have hedged approximately 80% of our expected natural gas, NGL and condensate commodity price risk through 2010 and approximately 60% of our expected condensate commodity price risk in 2011.

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Item 4. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

Our management, including the Chief Financial Officer and the Chief Executive Officer of DCP Midstream GP, LLC, have evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and concluded that, as of the end of the period covered by this report, the disclosure controls and procedures are effective in ensuring that all material information required to be filed in this quarterly report has been made known to them in a timely fashion. The required information was effectively recorded, processed, summarized and reported within the time period necessary to prepare this quarterly report. Our disclosure controls and procedures are effective in ensuring that information required to be disclosed in our reports under the Exchange Act are accumulated and communicated to management, including the Chief Financial Officer and the Chief Executive Officer of DCP Midstream GP, LLC, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the six months ended June 30, 2006 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

The information required for this item is provided in Note 9, Commitments and Contingent Liabilities, included in the notes to condensed consolidated financial statements included under Part I. Item 1, which information is incorporated by reference into this item.

Item 6. *Exhibits*

Exhibits

Exhibit Number	Description
10.6	First Amendment to Omnibus Agreement, dated April 1, 2006, among Duke Energy Field Services, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP and DCP Midstream Operating, LP.
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Denver, State of Colorado, on August 11, 2006.

DCP Midstream Partners, LP

By: DCP Midstream GP, LP
its General Partner

By: DCP Midstream GP, LLC
its General Partner

By: /s/ Thomas E. Long

Name: Thomas E. Long
Title: Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)

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