UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended: June 30, 2007

or

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

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 ☐ Accelerated filer ☒ Non-accelerated filer ☐

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

As of August 3, 2007, there were outstanding 14,183,639 common limited partner units and 7,142,857 subordinated units.

DCP MIDSTREAM PARTNERS, LP
FORM 10-Q FOR THE QUARTER ENDED JUNE 30, 2007

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GLOSSARY OF TERMS

The following is a list of certain industry terms used throughout this report:

Bbls	barrels
Bbls/d	barrels per day
Frac spread	price differences, measured in energy units, between equivalent amounts of natural gas and NGLs
Fractionation	the process by which natural gas liquids are separated into individual components
MMBtu	million British thermal units, a measurement of energy
MMBtu/d	million British thermal units per day, a measurement of energy
MMcf/d	million cubic feet per day
NGLs	natural gas liquids
Throughput	the volume of product transported or passing through a pipeline or other facility

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,” “plan,” “forecast” and 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 this Quarterly Report on Form 10-Q and in our Annual Report on Form 10-K for the year ended December 31, 2006, as well as the following risks and uncertainties:

- the level and success of natural gas drilling around our assets, and our ability to connect supplies to our gathering and processing systems in light of competition;
- our ability to grow through acquisitions, contributions from affiliates, or organic growth projects, and the successful integration and future performance of such assets;
- our ability to access the debt and equity markets, which will depend on general market conditions, interest rates and our ability to effectively hedge such rates with derivative financial instruments to limit a portion of the adverse effects of potential changes in interest rates, and the credit ratings for our debt obligations;
- the extent of changes in commodity prices, our ability to effectively mitigate a portion of the adverse impact of potential changes in prices through derivative financial instruments, and the potential impact of price on natural gas drilling, demand for our services, and the volume of NGLs and condensate extracted;
- our ability to purchase propane from our principal suppliers for our wholesale propane logistics business;
- our ability to construct facilities in a timely fashion, which is partially dependent on obtaining required building, environmental and other permits issued by federal, state and municipal governments, or agencies thereof, the availability of specialized contractors and laborers, and the price of and demand for supplies;
- the creditworthiness of counterparties to our transactions;
- weather and other natural phenomena, including their potential impact on demand for the commodities we sell and our and third-party-owned infrastructure;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment or the increased regulation of our industry;
- industry changes, including the impact of consolidations, alternative energy sources, technological advances and changes in competition;
- the amount of collateral required to be posted from time to time in our transactions; 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, 2007	December 31, 2006
	($ in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 55.0	$ 46.2
Short-term investments	—	0.6
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.6 million and $0.3 million, respectively	40.2	43.4
Affiliates	30.4	34.8
Inventories	30.3	30.1
Unrealized gains on non-trading derivative and hedging instruments	3.2	4.2
Other	0.2	0.3
Total current assets	159.3	159.6
Restricted investments	—	102.0
Property, plant and equipment, net	370.7	194.7
Goodwill	29.3	29.3
Intangible assets, net	15.0	2.8
Equity method investments	6.4	5.9
Unrealized gains on non-trading derivative and hedging instruments	5.0	6.5
Other long-term assets	1.3	0.8
Total assets	$ 587.0	$ 501.6
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 70.7	$ 66.9
Affiliates	21.6	50.4
Unrealized losses on non-trading derivative and hedging instruments	4.4	0.7
Accrued interest payable	0.4	1.1
Other	7.3	7.4
Total current liabilities	104.4	126.5
Long-term debt	249.0	268.0
Unrealized losses on non-trading derivative and hedging instruments	10.3	2.7
Other long-term liabilities	2.3	1.0
Total liabilities	366.0	398.2
Commitments and contingent liabilities		
Partners' equity:		
Common unitholders (13,362,923 and 10,357,143 units issued and outstanding, respectively)	349.9	223.4
Class C unitholders (200,312 units issued and outstanding at both periods)	(20.7)	(20.7)
Subordinated unitholders (7,142,857 convertible units issued and outstanding at both periods)	(102.5)	(101.6)
General partner interest	(5.0)	(5.0)
Accumulated other comprehensive (loss) income	(0.5)	7.3
Total	221.2	103.4
Less treasury units, at cost (4,000 and 0, respectively)	(0.2)	—
Total partners' equity	221.0	103.4
Total liabilities and partners' equity	$ 587.0	$ 501.6

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	($ in millions, except per unit amounts)			
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 123.6	$ 107.5	$301.9	$291.6
Sales of natural gas, propane, NGLs and condensate to affiliates	62.0	46.1	116.6	121.0
Transportation and processing services	3.6	3.6	6.9	7.4
Transportation and processing services to affiliates	3.9	3.3	7.9	6.0
Losses from non-trading derivative activity, net	(5.8)	—	(5.8)	—
Losses from non-trading derivative activity — affiliates, net	(0.4)	(0.4)	(0.5)	(0.5)
Total operating revenues	186.9	160.1	427.0	425.5
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	129.5	113.8	292.6	324.3
Purchases of natural gas, propane and NGLs from affiliates	35.7	24.2	83.5	55.6
Operating and maintenance expense	6.3	5.1	12.9	11.5
Depreciation and amortization expense	4.5	3.1	7.9	6.4
General and administrative expense	4.5	2.7	7.0	5.5
General and administrative expense — affiliates	2.4	1.9	4.7	3.8
Total operating costs and expenses	182.9	150.8	408.6	407.1
Operating income	4.0	9.3	18.4	18.4
Interest income	0.8	1.5	2.5	3.0
Interest expense	(4.6)	(2.6)	(8.4)	(5.2)
Earnings from equity method investments	0.3	0.1	0.5	0.1
Net income	$ 0.5	$ 8.3	$ 13.0	$ 16.3
Less:				
Net loss (income) attributable to predecessor operations	—	0.5	—	(2.1)
General partner interest in net income	(0.3)	(0.2)	(0.6)	(0.3)
Net income allocable to limited partners	$ 0.2	$ 8.6	$ 12.4	$ 13.9
Net income per limited partner unit — basic and diluted	$ 0.01	$ 0.47	$ 0.60	$ 0.79
Weighted-average limited partner units outstanding — basic and diluted	18.0	17.5	17.8	17.5

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	($ in millions)			
Net income	$ 0.5	$ 8.3	$ 13.0	$ 16.3
Other comprehensive loss:				
Reclassification of cash flow hedge into earnings	(0.7)	(0.5)	(2.1)	(0.7)
Net unrealized losses on cash flow hedges	(0.4)	(2.4)	(5.7)	(2.8)
Total other comprehensive loss	(1.1)	(2.9)	(7.8)	(3.5)
Total comprehensive (loss) income	$ (0.6)	$ 5.4	$ 5.2	$ 12.8

See accompanying notes to condensed consolidated financial statements.

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

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	($ in millions)	
OPERATING ACTIVITIES:		
Net income	$ 13.0	$ 16.3
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	7.9	6.4
Undistributed earnings from equity method investments	(0.5)	(0.1)
Other, net	(0.4)	(1.4)
Change in operating assets and liabilities which provided (used) cash, net of effects from acquisitions:		
Accounts receivable	9.8	73.9
Inventories	(0.2)	12.4
Net unrealized losses on non-trading derivative and hedging instruments	6.2	0.9
Accounts payable	(14.2)	(83.0)
Accrued interest	(0.7)	(0.2)
Other current assets and liabilities	(0.2)	1.7
Other long-term assets and liabilities	0.6	—
Net cash provided by operating activities	21.3	26.9
INVESTING ACTIVITIES:		
Capital expenditures	(7.6)	(12.1)
Acquisition of assets	(191.3)	—
Payment of earnest deposit	(9.0)	—
Refund of earnest deposit	9.0	—
Proceeds from sales of assets	0.1	0.1
Purchases of available-for-sale securities	(6,427.7)	(4,249.8)
Proceeds from sales of available-for-sale securities	6,531.1	4,248.8
Net cash used in investing activities	(95.4)	(13.0)
FINANCING ACTIVITIES:		
Borrowings of debt	188.0	—
Repayments of debt	(207.0)	(20.1)
Proceeds from issuance of common units, net of offering costs	128.5	—
Payment of deferred financing costs	(0.5)	—
Purchase of treasury units	(0.2)	—
Excess purchase price over acquired assets	(9.9)	—
Net change in advances from DCP Midstream, LLC	—	(10.9)
Distributions to unitholders	(16.4)	(8.0)
Contributions from unitholders	0.4	3.2
Net cash provided by (used in) financing activities	82.9	(35.8)
Net change in cash and cash equivalents	8.8	(21.9)
Cash and cash equivalents, beginning of period	46.2	42.2
Cash and cash equivalents, end of period	$ 55.0	$ 20.3
Supplementary disclosure of cash flow information:		
Cash paid for interest, net of capitalized interest	$ 10.0	$ 5.4

See accompanying notes to condensed consolidated financial statements.

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

1. Description of Business and Basis of Presentation

DCP Midstream Partners, LP, with its consolidated subsidiaries, or us, we or our, is engaged in the business of gathering, compressing, treating, processing, transporting and selling natural gas and the business of producing, transporting and selling propane and natural gas liquids, or NGLs.

We are a Delaware master limited partnership that was formed in August 2005. We completed our initial public offering on December 7, 2005. Our partnership includes: our Northern Louisiana system assets; our Southern Oklahoma system (which was acquired in May 2007); our NGL transportation pipelines; and our wholesale propane logistics business (which was acquired in November 2006).

Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as the General Partner, which is wholly-owned by DCP Midstream, LLC. DCP Midstream, LLC is owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by ConocoPhillips.

The condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. We refer to the assets, liabilities and operations of our wholesale propane logistics business prior to our acquisition from DCP Midstream, LLC in November 2006, as our "predecessor." The condensed consolidated financial statements of our predecessor have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessor had been operated as an unaffiliated entity. All significant intercompany balances and transactions have been eliminated. Transactions between us and other DCP Midstream, LLC operations have been identified in the condensed consolidated financial statements as transactions between affiliates.

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, or SEC. 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 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, 2006.

2. Summary of Significant Accounting Policies

Use of Estimates — Conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the condensed consolidated 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.

Restricted Investments — Restricted investments consisted of $102.0 million in investments in commercial paper and various other high-grade debt securities as of December 31, 2006. These investments were used as collateral to secure the term loan portion of our credit facility and to finance gathering and compression asset acquisitions. There were no restricted investments as of June 30, 2007.

Accounting for Risk Management and Hedging Activities and Financial Instruments — Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. We will use the mark-to-market method of accounting for all commodity cash flow hedges beginning in July 2007. As a result, the remaining net loss of $2.0 million deferred in accumulated other comprehensive income, or AOCI, as of June 30, 2007 will be reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the hedged transactions impact earnings.

Revenue Recognition — We generate the majority of our revenues from gathering, processing, compressing, transporting, and fractionating natural gas and NGLs, and from trading and marketing of natural gas and NGLs. We realize revenues either by selling the residue natural gas and NGLs, or by receiving fees from the producers.

We obtain access to commodities and provide our midstream services principally under contracts that contain a combination of one or more of the following 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; and transporting NGLs. 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, generally the same as the transportation fees we would otherwise charge for transportation of natural gas from the wellhead location to the delivery point. The revenues we earn are directly related to the volume of natural gas or NGLs that flows through our systems and are 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/index arrangements* — Under percentage-of-proceeds/index arrangements, we generally purchase natural gas from producers at the wellhead, or other receipt points, gather the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and NGLs based on index prices from 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. Certain of these arrangements may also result in our returning all or a portion of the residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. Our revenues under percentage-of-proceeds/index arrangements correlate directly with the price of natural gas and/or NGLs.

- *Propane sales arrangements* — Under propane sales arrangements, we generally purchase propane from natural gas processing plants and fractionation facilities, and crude oil refineries. We sell propane on a wholesale basis to retail propane distributors, who in turn resell to their retail customers. Our sales of propane are not contingent upon the resale of propane by propane distributors to their retail customers.

Our marketing of natural gas and NGLs consists of physical purchases and sales, as well as positions in derivative instruments.

We generally report revenues gross in the condensed consolidated statements of operations, as we typically act as the principal in these transactions, take custody to the product, and incur the risks and rewards of ownership. Effective April 1, 2006, any new or amended contracts for certain sales and purchases of inventory with the same counterparty, when entered into in contemplation of one another, are reported net as one transaction.

3. Recent Accounting Pronouncements

***Statement of Financial Accounting Standards, or SFAS, No. 159, The Fair Value Option for Financial Assets and Financial Liabilities—including an amendment of FAS 115*, or SFAS 159** — In February 2007, the Financial Accounting Standards Board, or FASB, issued SFAS 159, which allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item's fair value in subsequent reporting periods must be recognized in current earnings. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between entities that elect different measurement attributes for similar assets and liabilities. SFAS 159 is effective for us on January 1, 2008. We have not assessed the impact of SFAS 159 on our consolidated results of operations, cash flows or financial position.

***SFAS No. 157, Fair Value Measurements*, or SFAS 157** — In September 2006, the FASB issued SFAS 157, which provides guidance for using fair value to measure assets and liabilities. The standard also responds to investors' requests for more information about: (1) the extent to which companies measure assets and liabilities at fair value; (2) the information used to measure fair value; and (3) the effect that fair value measurements have on earnings. SFAS 157 will apply whenever another standard requires (or permits) assets or liabilities to be measured at fair value. SFAS 157 does not expand the use of fair value to any new circumstances. SFAS 157 is effective for us on January 1, 2008. We have not assessed the impact of SFAS 157 on our consolidated results of operations, cash flows or financial position.

***FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes—An Interpretation of FASB Statement 109*, or FIN 48** — In July 2006, the FASB issued FIN 48, which clarifies the accounting for uncertainty in income taxes recognized in financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The provisions of FIN 48 were effective for us on January 1, 2007, and the adoption of FIN 48 did not have a material impact on our consolidated results of operations, cash flows or financial position.

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4. Acquisitions

Gathering and Compression Assets

On July 1, 2007, we acquired a 25% limited liability company interest in DCP East Texas Holdings, LLC, a 40% limited liability company interest in Discovery Producer Services LLC and a derivative instrument from DCP Midstream, LLC for aggregate consideration consisting of $244.7 million in cash, the issuance of 620,404 common units valued at $27.0 million and the issuance of 12,661 general partner equivalent units valued at $0.6 million.

In May 2007, we agreed to acquire certain subsidiaries of Momentum Energy Group Inc., or MEG, from DCP Midstream, LLC for $165.0 million, subject to closing adjustments. This transaction is expected to close in the third quarter of 2007, but is contingent upon DCP Midstream, LLC closing their acquisition of the stock of MEG. On May 21, 2007, in connection with this acquisition, we entered into a common unit purchase agreement, which is contingent on the closing of the MEG acquisition, with certain institutional investors to sell 2,380,952 common limited partner units in a private placement at $42.00 per unit, or approximately $100.0 million in the aggregate. In connection with this common unit purchase agreement, we have a registration obligation that is contingent upon closing of the MEG acquisition.

In May 2007, we acquired certain gathering and compression assets located in Southern Oklahoma, as well as related commodity purchase contracts, from Anadarko Petroleum Corporation for approximately $181.1 million, subject to customary purchase price adjustments.

In April 2007, we acquired certain gathering and compression assets located in Northern Louisiana from Laser Gathering Company, LP for approximately $10.2 million, subject to customary purchase price adjustments.

The results of operations for these acquired assets have been included prospectively, from the dates of acquisition, as part of the Natural Gas Services segment.

Wholesale Propane Logistics Business

On November 1, 2006, we acquired our wholesale propane logistics business from DCP Midstream, LLC for aggregate consideration of approximately $82.9 million, which consisted of $77.3 million in cash ($9.9 million of which was paid in January 2007), and the issuance of 200,312 Class C units valued at approximately $5.6 million. Included in the aggregate consideration was $10.5 million of costs incurred through October 31, 2006, which were associated with the construction of a new pipeline terminal.

The transfer of assets between DCP Midstream, LLC and us represents a transfer of assets between entities under common control. Transfers of net assets or exchanges of shares between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retroactively adjusted to furnish comparative information similar to the pooling method.

The following tables present the impact on our unaudited condensed consolidated statement of operations, adjusted for the acquisition of our wholesale propane logistics business from DCP Midstream, LLC, for the three and six months ended June 30, 2006 ($ in millions):

Three Months Ended June 30, 2006

	DCP Midstream Partners, LP	Wholesale Propane Logistics Business	Combined DCP Midstream Partners, LP
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 88.1	$ 65.5	$ 153.6
Transportation and other	6.9	(0.4)	6.5
Total operating revenues	95.0	65.1	160.1
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	75.7	62.3	138.0
Operating and maintenance expense	3.0	2.1	5.1
Depreciation and amortization expense	2.9	0.2	3.1
General and administrative expense	3.6	1.0	4.6
Total operating costs and expenses	85.2	65.6	150.8
Operating income	9.8	(0.5)	9.3
Interest expense, net	(1.1)	—	(1.1)
Earnings from equity method investments	0.1	—	0.1
Net income	$ 8.8	$ (0.5)	$ 8.3

Six Months Ended June 30, 2006

	DCP Midstream Partners, LP	Wholesale Propane Logistics Business	Combined DCP Midstream Partners, LP
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 201.6	$ 211.0	$ 412.6
Transportation and other	13.4	(0.5)	12.9
Total operating revenues	215.0	210.5	425.5
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	177.8	202.1	379.9
Operating and maintenance expense	7.3	4.2	11.5
Depreciation and amortization expense	5.9	0.5	6.4
General and administrative expense	7.7	1.6	9.3
Total operating costs and expenses	198.7	208.4	407.1
Operating income	16.3	2.1	18.4
Interest expense, net	(2.2)	—	(2.2)
Earnings from equity method investments	0.1	—	0.1
Net income	$ 14.2	$ 2.1	$ 16.3

5. Agreements and Transactions with Affiliates

DCP Midstream, LLC

DCP Midstream, LLC provided centralized corporate functions on behalf of our predecessor operations, 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. The predecessor's share of those costs was allocated based on the predecessor's proportionate net investment (consisting of property, plant and equipment, net, equity method investments, and intangible assets, net) as compared to DCP Midstream, LLC's net investment. In management's estimation, the allocation methodologies used were reasonable and resulted in an allocation to the predecessors of their respective costs of doing business, which were borne by DCP Midstream, LLC.

Omnibus Agreement

We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee for centralized corporate functions performed by DCP Midstream, LLC 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. The Omnibus Agreement: (1) states that the annual fee of $4.8 million for the initial assets under the agreement was fixed at such amount for 2006, subject to annual increases in the Consumer Price Index, which increased to $5.0 million for 2007; (2) effective November 2006, includes an additional annual fee of $2.0 million related to the acquisition of our wholesale propane logistics business from DCP Midstream, LLC, subject to the same conditions noted above; and (3) effective May 2007, includes an additional annual fee of $0.2 million related to the Southern Oklahoma asset acquisition, subject to the same conditions noted above.

The Omnibus Agreement addresses the following matters:

- our obligation to reimburse DCP Midstream, LLC for the payment of operating expenses, including salary and benefits of operating personnel, it incurs on our behalf in connection with our business and operations;
- our obligation to reimburse DCP Midstream, LLC for providing us with general and administrative services with respect to our business and operations, which is $7.2 million in 2007, subject to an increase for 2008 based on increases in the Consumer Price Index and subject 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 the General Partner's board of directors;

- our obligation to reimburse DCP Midstream, LLC for insurance coverage expenses it incurs with respect to our business and operations and with respect to director and officer liability coverage;
- DCP Midstream, LLC's obligation to indemnify us for certain liabilities and our obligation to indemnify DCP Midstream, LLC for certain liabilities;
- DCP Midstream, LLC's obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to derivative financial instruments, such as commodity price hedging contracts, to the extent that such credit support arrangements were in effect as of the closing of our initial public offering in December 2005, until the earlier to occur of the fifth anniversary of the closing of our initial public offering or such time as we obtain an investment grade credit rating from either Moody's Investor Services, Inc. or Standard & Poor's Ratings Group with respect to any of our unsecured indebtedness; and
- DCP Midstream, LLC's obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to commercial contracts with respect to its business or operations that were in effect at the closing of our initial public offering until the expiration of such contracts.

Any or all of the provisions of the Omnibus Agreement, other than the indemnification provisions, will be terminable by DCP Midstream, LLC at its option if the general partner is removed without cause and units held by the general partner and its affiliates are not voted in favor of that removal. The Omnibus Agreement will also terminate in the event of a change of control of us, the general partner (DCP Midstream GP, LP) or the General Partner (DCP Midstream GP, LLC).

Indemnification

Under the Omnibus Agreement, DCP Midstream, LLC will indemnify 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 date of our initial public offering. DCP Midstream, LLC's maximum liability for this indemnification obligation does not exceed $15.0 million and DCP Midstream, LLC does not have any obligation under this indemnification until our aggregate losses exceed $250,000. DCP Midstream, LLC 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 DCP Midstream, LLC against environmental liabilities related to our assets to the extent DCP Midstream, LLC is not required to indemnify us.

Additionally, DCP Midstream, LLC will indemnify us for losses attributable to title defects, retained assets and liabilities (including preclosing litigation relating to contributed assets) and income taxes attributable to pre-closing operations. We will indemnify DCP Midstream, LLC for all losses attributable to the postclosing operations of the assets contributed to us, to the extent not subject to DCP Midstream, LLC's indemnification obligations. In addition, DCP Midstream, LLC 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 Pipe Line Company, or 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. DCP Midstream, LLC had also agreed to indemnify us for up to $4.0 million of the costs associated with any repairs to the Seabreeze pipeline that were determined to be necessary as a result of pipeline integrity testing that occurred in 2006. Pipeline integrity testing and repairs were our responsibility and were recognized as operating and maintenance expense. Reimbursement of these expenses from DCP Midstream, LLC were not significant and were recognized by us as capital contributions.

Other Agreements and Transactions with DCP Midstream, LLC

DCP Midstream, LLC owns certain assets and is party to certain contractual relationships around our Pelico system that are periodically used for the benefit of Pelico. DCP Midstream, LLC 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 DCP Midstream, LLC's ability to move natural gas around Pelico, there are certain contractual relationships around Pelico that define how natural gas is bought and sold between us and DCP Midstream, LLC. The agreement is described below:

- DCP Midstream, LLC will supply Pelico's system requirements that exceed its on-system supply. Accordingly, DCP Midstream, LLC purchases natural gas and transports it to our Pelico system, where we buy the gas from DCP Midstream, LLC 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, propane and NGLs from affiliates.

- If our Pelico system has volumes in excess of the on-system demand, DCP Midstream, LLC 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, propane and NGLs to affiliates.
- In addition, DCP Midstream, LLC may purchase other excess natural gas volumes at certain Pelico outlets for a price that equals the original Pelico purchase price from DCP Midstream, LLC, 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.

In addition, we sell NGLs and condensate from our Minden and Ada processing plants, and condensate from our Pelico system to a subsidiary of DCP Midstream, LLC equal to that subsidiary's 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, propane, NGLs and condensate to affiliates. We also sell propane to a subsidiary of DCP Midstream, LLC.

We also have a contractual arrangement with a subsidiary of DCP Midstream, LLC that provides that DCP Midstream, LLC will pay us to transport NGLs over our Seabreeze pipeline, pursuant to a fee-based rate that will be applied to the volumes transported. DCP Midstream, LLC is the sole shipper on the Seabreeze pipeline under a 17-year transportation agreement expiring in 2022. We generally report revenues associated with these activities in the condensed consolidated statements of operations as transportation and processing services to affiliates.

In December 2006, we completed construction of our Wilbreeze pipeline, which connects a DCP Midstream, LLC gas processing plant to our Seabreeze pipeline. The project is supported by a 10-year NGL product dedication agreement with DCP Midstream, LLC. We generally report revenues, which are earned pursuant to a fee-based rate applied to the volumes transported on this pipeline, in the condensed consolidated statements of operations as transportation and processing services to affiliates.

We anticipate continuing to purchase commodities from and sell commodities to DCP Midstream, LLC in the ordinary course of business.

DCP Midstream, LLC was a significant customer during the three and six months ended June 30, 2007 and 2006.

Duke Energy

Prior to December 31, 2006, we charged transportation fees, sold a portion of our residue gas to, and purchased raw natural gas from, Duke Energy Corporation, or Duke Energy, and its affiliates.

ConocoPhillips

We have multiple agreements whereby we provide a variety of services to ConocoPhillips and its affiliates. The agreements include fee-based and percentage-of-proceeds gathering and processing arrangements, gas purchase and gas sales agreements. We anticipate 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 $1.5 million and $1.2 million of capital reimbursements during the six months ended June 30, 2007 and 2006, respectively.

The following table summarizes the transactions with affiliates ($ in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
DCP Midstream, LLC:				
Sales of natural gas, propane, NGLs and condensate	$ 59.3	$ 46.0	$113.9	$120.9
Transportation and processing services	$ 1.3	$ 1.3	$ 2.9	$ 2.5
Purchases of natural gas, propane and NGLs	$ 30.0	$ 20.1	$ 70.0	$ 48.0
Losses from non-trading derivative activity, net	$ (0.4)	$ (0.4)	$ (0.5)	$ (0.5)
General and administrative expense	$ 2.4	$ 1.9	$ 4.7	$ 3.8
Duke Energy:				
Purchases of natural gas, propane and NGLs	$ —	$ 1.7	$ —	$ 1.9
ConocoPhillips:				
Sales of natural gas, propane, NGLs and condensate	$ 2.7	$ 0.1	$ 2.7	$ 0.1
Transportation and processing services	$ 2.6	$ 2.0	$ 5.0	$ 3.5
Purchases of natural gas, propane and NGLs	$ 5.7	$ 2.4	$ 13.5	$ 5.7

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

	June 30, 2007	December 31, 2006
DCP Midstream, LLC:		
Accounts receivable	$ 19.9	$ 30.0
Accounts payable	$ 19.5	$ 46.6
Spectra Energy:		
Accounts receivable	$ 0.3	$ —
Duke Energy:		
Accounts receivable	$ —	$ 0.2
Accounts payable	$ —	$ 1.8
ConocoPhillips:		
Accounts receivable	$ 10.2	$ 4.6
Accounts payable	$ 2.1	$ 2.0

6. Intangible Assets

Intangible assets consist primarily of commodity purchase contracts. The gross carrying amount and accumulated amortization for the commodity purchase contracts and other intangible assets are included in the accompanying condensed consolidated balance sheets as intangible assets, net, and were as follows ($ in millions):

	June 30, 2007	December 31, 2006
Gross carrying amount	$ 16.9	$ 4.4
Accumulated amortization	(1.9)	(1.6)
Intangible assets, net	$ 15.0	$ 2.8

Intangible assets increased in May 2007 as a result of the Southern Oklahoma asset acquisition, through which $12.5 million of net commodity purchase contracts were acquired. These intangible assets have a life of 15 years and are being amortized through 2022.

For the three and six months ended June 30, 2007, we recorded amortization expense associated with these intangibles of $0.2 million and $0.3 million, respectively. For the three and six months ended June 30, 2006, we recorded amortization expense associated with these intangibles of $0.1 million and $0.3 million, respectively.

7. Debt

Long-term debt was as follows ($ in millions):

	Principal Amount	
	June 30, 2007	December 31, 2006
Revolving credit facility, weighted-average interest rate of 5.77% at June 30, 2007, due June 21, 2012	$249.0	$ 168.0
Term loan facility	—	100.0
Total long-term debt	$249.0	$ 268.0

Credit Agreements

On June 21, 2007, we entered into the Amended and Restated Credit Agreement, or the Amended Credit Agreement, that replaced our existing credit agreement, or the Credit Agreement, which consists of:

- a $600.0 million revolving credit facility; and
- a $250.0 million term loan facility.

At June 30, 2007, we had $0.2 million of letters of credit outstanding. Outstanding balances under the term loan facility are fully collateralized by investments in high-grade securities, which are classified as restricted investments in the accompanying condensed consolidated balance sheet as of December 31, 2006. In June 2007, we incurred $0.5 million of debt issuance costs associated with the Amended Credit Agreement. These expenses are deferred as other long-term assets in the condensed consolidated balance sheet and will be amortized over the term of the Amended Credit Agreement.

Under the Amended Credit Agreement, indebtedness under the revolving credit facility bears interest at either: (1) the higher of Wachovia Bank's prime rate or the federal funds rate plus 0.50%; or (2) LIBOR plus an applicable margin, which ranges from 0.23% to 0.575% dependent upon our leverage level or credit rating. As of June 30, 2007, the weighted-average interest rate on our revolving credit facility was 5.77% per annum. The revolving credit facility incurs an annual facility fee of 0.07% to 0.175% depending on our applicable leverage level or debt rating. This fee is paid on drawn and undrawn portions of the revolving credit facility. The term loan facility bears interest at a rate equal to either: (1) LIBOR plus 0.10%; or (2) the higher of Wachovia Bank's prime rate or the federal funds rate plus 0.50%.

The Amended 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 Amended Credit Agreement) of not more than 5.75 to 1.0 through and including the quarter ended June 30, 2007 and 5.0 to 1.0 thereafter, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of asset acquisitions in the midstream energy business of not more than 5.50 to 1.0. The Amended 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 Amended Credit Agreement) of equal or greater than 2.5 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination.

Bridge Loan

In May 2007, we entered into a two-month bridge loan, or the Bridge Loan, which provided for borrowings up to $100.0 million, and had terms and conditions substantially similar to those of our Credit Agreement. In conjunction with our entering into the Bridge Loan, our Credit Agreement was amended to provide for additional unsecured indebtedness, of an amount not to exceed $100.0 million, which was due and payable no later than August 9, 2007.

We used borrowings on the Bridge Loan of $88.0 million to partially fund the Southern Oklahoma asset acquisition. The remaining $12.0 million available for borrowing on the Bridge Loan was not utilized. We used a portion of the net proceeds of a private placement of limited partner units to extinguish the $88.0 million outstanding on the Bridge Loan.

8. 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 (defined below) to unitholders of record on the applicable record date, as determined by our general partner.

In April 2007, we filed with the SEC a universal shelf registration statement on Form S-3 with a maximum aggregate offering price of $1.5 billion, which will, upon effectiveness, allow us to register and issue additional partnership units and debt obligations.

On June 22, 2007, we entered into a private placement agreement, or the Private Placement Agreement, with a group of institutional investors for $130.0 million, representing 3,005,780 common limited partner units at a price of $43.25 per unit, and received proceeds of $128.5 million, net of offering costs. In connection with the Private Placement Agreement, we entered into a registration rights agreement with institutional investors that requires us to file a shelf registration statement with the Securities and Exchange Commission, or SEC, to register the units by the earlier of within 120 days of the close of the private placement or when a shelf registration statement is filed to register the units to be issued and sold by us under a common unit purchase agreement, which is contingent on the closing of the MEG acquisition. In addition the registration rights agreement requires us to use our commercially reasonable efforts to cause the registration statement to become effective within 210 days of the closing of the private placement, or we will be liable to the institutional investors for liquidated damages of 0.25% of the product of the purchase price times the number of registrable securities held by the institutional investors per 30-day period for the first 60 days following the 210th day, increasing by an additional 0.25% of the product of the purchase price times the number of registrable securities held by the institutional investors per 30-day period for each subsequent 60 days, up to a maximum of 1.00% of the product of the purchase price times the number of registrable securities held by the institutional investors per 30-day period.

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:
  - 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 our general partner for any one or more of the next four quarters;
- plus, if our 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 — Prior to June 22, 2007, the general partner was entitled to 2% of all quarterly distributions that we make prior to our liquidation. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its general partner interest. The general partner's 2% interest in these distributions was reduced to 1.7% on June 22, 2007 as a result of the issuance of the 3,005,780 common limited partner units in conjunction with the Private Placement Agreement.

The incentive distribution rights held by the general partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. The general partner's incentive distribution rights were not reduced as a result of the Private Placement Agreement, and will not 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 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.

Class C Units — The Class C units have the same liquidation preference, rights to cash distributions and voting rights as the common units. On July 2, 2007, the Class C units were converted to common units.

Subordinated Units — All of the subordinated units are held by DCP Midstream, LLC. Our 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 subordination period has an early termination provision that permits 50% of the subordinated units to convert to common units on the second business day following the first quarter distribution in 2008 and the other 50% of the subordinated units to convert to common units on the second business day following the first quarter distribution in 2009, provided the tests for ending the subordination period contained in the partnership agreement are satisfied. The rights of the subordinated unitholders, other than the distribution rights described above, are substantially the same as the rights of the common unitholders.

Treasury Units — In March 2007, we purchased 4,000 units on the open market, at an average cost of $39.16 per unit. These units were held as treasury units at June 30, 2007, and will be used for director compensation pursuant to the DCP Midstream Partners, LP Long-Term Incentive Plan, or LTIP.

Distributions of Available Cash during the Subordination Period — Our partnership agreement, after adjustment for the general partner's relative ownership level, currently 1.7%, requires that we make distributions of Available Cash for any quarter during the subordination period in the following manner:

- *first,* to the common unitholders and the general partner, in accordance with their pro rata interest, until we distribute for each outstanding common unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *second,* to the common unitholders and the general partner, in accordance with their pro rata interest, 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,* to the subordinated unitholders and the general partner, in accordance with their pro rata interest, until we distribute for each subordinated unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *fourth,* to all unitholders and the general partner, in accordance with their pro rata interest, until each unitholder receives a total of $0.4025 per unit for that quarter (the First Target Distribution);
- *fifth,* 13% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.4375 per unit for that quarter (the Second Target Distribution);
- *sixth,* 23% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.525 per unit for that quarter (the Third Target Distribution); and
- *thereafter,* 48% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders (the Fourth Target Distribution).

Distributions of Available Cash after the Subordination Period — Our partnership agreement after adjustment for the general partner's relative ownership level requires that we make distributions of Available Cash from operating surplus for any quarter after the subordination period in the following manner:

- *first,* to all unitholders and the general partner, in accordance with their pro rata interest, until each unitholder receives a total of $0.4025 per unit for that quarter;
- *second,* 13% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.4375 per unit for that quarter;
- *third,* 23% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.525 per unit for that quarter; and
- *thereafter,* 48% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders.

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The following table presents our cash distributions paid in 2007 and 2006 ($ in millions, except per unit distribution amounts):

Payment Date	Per Unit Distribution	Total Cash Distribution
May 15, 2007	$ 0.465	$ 8.6
February 14, 2007	0.430	7.8
November 14, 2006	0.405	7.4
August 14, 2006	0.380	6.7
May 15, 2006	0.350	6.3
February 13, 2006 (a)	0.095	1.7

(a) Represents 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.

9. Risk Management and Hedging Activities

The impact of our derivative activity on our results of operations and financial position is summarized below ($ in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Commodity cash flow hedges:				
Losses due to ineffectiveness	$ —	$ (0.1)	$ —	$ (0.5)
Gains reclassified into earnings as a result of settlements	$ 0.6	$ 0.5	$ 1.8	$ 0.7
Commodity non-trading derivative activity:				
Losses from non-trading derivative activity	$ (6.2)	$ (0.4)	$ (6.3)	$ (0.5)
Interest rate cash flow hedges:				
Gains reclassified into earnings as a result of settlements	$ 0.1	$ —	$ 0.3	$ —

	June 30, 2007	December 31, 2006
Commodity cash flow hedges:		
Net deferred (losses) gains in AOCI	$ (2.0)	$ 6.9
Interest rate cash flow hedges:		
Net deferred gains in AOCI	$ 1.5	$ 0.4

For the three and six months ended June 30, 2007 and 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.

Commodity Cash Flow Hedges — We use natural gas and crude oil swaps to mitigate the risk 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 as sales of natural gas, propane, NGLs and condensate. 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 impacts earnings, 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, 2007, $0.2 million of deferred net gains on derivative instruments in AOCI will be reclassified into earnings during the next 12 months as the hedged transactions impact earnings.

Commodity Fair Value Hedges — We use fair value hedges to mitigate risk 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, 2007 and 2006 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, 2007 and 2006, 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 — Our operations of gathering, processing, and transporting natural gas, and the accompanying operations of 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. 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. We occasionally will enter into financial derivatives to lock in price variability across the Pelico system to maximize the value of pipeline capacity. These financial derivatives are accounted for using mark-to-market accounting with changes in fair value recognized in current period earnings.

Our wholesale propane logistics business is generally designed to establish stable margins by entering into supply arrangements that specify prices based on established floating price indices and by entering into sales agreements that provide for floating prices that are tied to our variable supply costs plus a margin. Occasionally, we may enter into fixed price sales agreements in the event that a retail propane distributor desires to purchase propane from us on a fixed price basis. We manage this risk with both physical and financial transactions, sometimes using non-trading derivative instruments, which generally allow us to swap our fixed price risk to market index prices that are matched to our market index supply costs. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories. These financial derivatives are accounted for using mark-to-market accounting with changes in fair value recognized in current period earnings. We manage our asset-based activities in accordance with our risk management policy, which limits exposure to market risk and requires regular reporting to management of potential financial exposure. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories.

In May 2007, we executed a series of financial derivatives to mitigate a portion of the commodity exposure associated with the Southern Oklahoma asset acquisition. We entered into natural gas swap contracts for 1,500 MMBtu/d at $7.54 per MMBtu and into crude oil swap contracts for 650 Bbls/d at $67.60 per Bbl for a term from June 2007 through December 2013. In June 2007, we executed a series of financial derivatives to mitigate a portion of the commodity price exposure associated with our Northern Louisiana system assets. We entered into crude oil swap contracts for 250 Bbls/d at $71.35/Bbl for 2011, 600 Bbls/d at $71.00/Bbl for 2012 and 600 Bbls/d at $71.20/Bbl for 2013. These financial derivatives are accounted for using mark-to-market accounting with changes in fair value recognized in current period earnings.

Interest Rate Cash Flow Hedges — During 2006, we entered into interest rate swap agreements to hedge the variable interest rate on $125.0 million of the indebtedness outstanding under our revolving credit facility. 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 condensed consolidated balance sheets. As of June 30, 2007, $0.4 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 impact earnings; 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 fixed rates ranging from 4.68% to 5.08%, and receive interest payments based on the three-month LIBOR. 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.

10. Equity-Based Compensation

Total compensation cost for equity-based arrangements was as follows ($ in millions):

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Performance Units	$ 0.4	$ 0.1	$ 0.5	$ 0.1
Phantom Units	0.3	0.1	0.4	0.2
Total compensation cost	$ 0.7	$ 0.2	$ 0.9	$ 0.3

On November 28, 2005, the board of directors of the General Partner adopted the LTIP for employees, consultants and directors of the General Partner and its affiliates who perform services for us, effective as of December 7, 2005. Under the LTIP, equity-based instruments may be granted to our key employees. The LTIP provides for the grant of LPUs, phantom units, unit options and substitute awards, and, with respect to unit options and phantom units, the grant of distribution equivalent rights, or DERs. Subject to adjustment for certain events, an aggregate of 850,000 LPUs may be delivered pursuant to awards under the LTIP. Awards that are canceled, forfeited or withheld to satisfy the General Partner's tax withholding obligations are available for delivery pursuant to other awards. The LTIP is administered by the compensation committee of the General Partner's board of directors.

Performance Units — We have awarded phantom LPUs, or Performance Units, pursuant to the LTIP to certain employees. Performance Units generally vest in their entirety at the end of a three year performance period. The number of Performance Units that will ultimately vest range from 0% to 150% of the outstanding Performance Units, depending on the achievement of specified performance targets over three year performance periods. The final performance payout is determined by the compensation committee of the board of directors of the General Partner. Each Performance Unit includes a DER, which will be paid in cash at the end of the performance period.

At June 30, 2007, there was approximately $1.8 million of unrecognized compensation expense related to the Performance Units that is expected to be recognized over a weighted-average period of 2.1 years. The following table presents information related to the Performance Units:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at December 31, 2006	23,090	$ 26.96	
Granted	29,610	$ 37.23	
Outstanding at June 30, 2007	52,700	$ 32.73	$ 46.62
Expected to vest	52,700	$ 32.73	$ 46.62

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 — In conjunction with our initial public offering, in January 2006 the General Partner's board of directors awarded phantom LPUs, or Phantom Units, to key employees, and to directors who are not officers or employees of affiliates of the General Partner. Of these Phantom Units, 16,700 units will vest upon the three year anniversary of the grant date, and 5,332 units vest ratably over two years. Each Phantom Unit includes a DER, which is paid quarterly in arrears.

In May 2007, we granted 4,000 Phantom Units under the LTIP to directors who are not officers or employees of affiliates of the General Partner as part of their annual director fees for 2007. These Phantom Units will fully vest six months following the grant date. Each Phantom Unit includes a DER, which is paid quarterly in arrears.

At June 30, 2007, there was approximately $0.6 million of unrecognized compensation expense related to the Phantom Units that is expected to be recognized over a weighted-average period of 1.1 years. The following table presents information related to the Phantom Units:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at December 31, 2006	24,700	$ 24.05	
Granted	4,000	$ 42.69	
Vested or paid in cash	(2,668)	$ 24.05	
Outstanding at June 30, 2007	26,032	$ 26.91	$ 46.62
Expected to vest	26,032	$ 26.91	$ 46.62

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 awards issued under the LTIP in cash upon vesting, with the exception of the units granted in May 2007. 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 our common units at each measurement date. During the six months ended June 30, 2007, 2,668 awards vested and were settled in cash for $0.1 million. No awards were vested or settled during the three and six months ended June 30, 2006.

11. 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.

Securities that meet the definition of a participating security are required to 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.

These required disclosures do 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 LPU. 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 does not exceed the First Target Distribution Level, there is no impact on our calculation of earnings per LPU. During the three months ended June 30, 2007, our aggregate net income per LPU was less than the First Target Distribution level, and as a result there was no impact on our calculation of earnings per LPU. During the six months ended June 30, 2007, our aggregate net income per LPU exceeded the Third Target Distribution level, and as a result we allocated $1.8 million in additional earnings to the general partner. During the three months ended June 30, 2006, our aggregate net income per LPU exceeded the Second Target Distribution level, and as a result we allocated $0.3 million in additional earnings to the general partner. During the six months ended June 30, 2006, our aggregate net income per LPU was less than the First Target Distribution level, and as a result there was no impact on our calculation of earnings per LPU.

Basic and diluted net income per LPU is calculated by dividing limited partners' interest in net income, less pro forma general partner incentive distributions as described above, by the weighted-average number of outstanding LPUs during the period.

The following table illustrates our calculation of net income per LPU ($ in millions):

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Net income	$ 0.5	$ 8.3	$ 13.0	$ 16.3
Less:				
Net loss (income) attributable to predecessor operations	—	0.5	—	(2.1)
Net income attributable to the partnership	0.5	8.8	13.0	14.2
Less: General partner interest in net income	(0.3)	(0.2)	(0.6)	(0.3)
Limited partners' interest in net income	0.2	8.6	12.4	13.9
Less: Additional earnings allocation to general partner	—	(0.3)	(1.8)	—
Net income available to limited partners	$ 0.2	$ 8.3	$ 10.6	$ 13.9
Net income per LPU — basic and diluted	$ 0.01	$ 0.47	$ 0.60	$ 0.79

12. Commitments and Contingent Liabilities

Litigation

El Paso — In December 2006, El Paso E&P Company, L.P., or El Paso, filed a lawsuit against one of our subsidiaries, DCP Assets Holding, LP and an affiliate of our general partner, DCP Midstream GP, LP, in District Court, Harris County, Texas. The litigation stems from an ongoing commercial dispute involving our Minden processing plant that dates back to August 2000, which is prior to our ownership of this asset. El Paso claims damages, including interest, in the amount of $5.7 million in the litigation, the bulk of which stems from audit claims under our commercial contract for historical periods prior to our ownership of this asset. We will only be responsible for potential payments, if any, for claims that involve periods of time after the date we acquired this asset from DCP Midstream, LLC in December 2005. It is not possible to predict whether we will incur any liability or to estimate the damages, if any, we might incur in connection with this matter. Management does not believe the ultimate resolution of this issue will have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Other — We are not a party to any other significant legal proceedings, but are a party to various administrative and regulatory proceedings and commercial disputes that have arisen in the ordinary course of our business. Management currently believes that the ultimate resolution of the foregoing 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 consolidated results of operations, financial position, or cash flows.

Indemnification — DCP Midstream, LLC 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. See the "Indemnification" section of Note 5 for additional details.

13. Business Segments

Our operations are located in the United States and are organized into three reporting segments: (1) Natural Gas Services; (2) Wholesale Propane Logistics; and (3) NGL Logistics.

Natural Gas Services — The Natural Gas Services segment consists of the Northern Louisiana system assets, an integrated gas gathering, compression, treating, processing, and transportation system located in northern Louisiana, as well as the Southern Oklahoma system that was acquired in May 2007.

Wholesale Propane Logistics — The Wholesale Propane Logistics segment consists of six owned propane rail terminals located in the Midwest and northeastern United States, one leased propane marine terminal located in Providence, Rhode Island, one propane pipeline terminal in Midland, Pennsylvania and access to several open access pipeline terminals.

NGL Logistics — The NGL Logistics segment consists of the Seabreeze and Wilbreeze NGL transportation pipelines, which are located along the Gulf Coast area of southeastern Texas, and a non-operated 45% equity interest in the Black Lake interstate NGL pipeline located in northern Louisiana and southeastern Texas. The Wilbreeze transportation pipeline was not operational until December 2006.

These segments are monitored separately by management for performance against our 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 following tables set forth our segment information ($ in millions):

Three Months Ended June 30, 2007

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(b)	Total
Total operating revenue	$ 110.0	$ 75.2	$ 1.7	$ —	$ 186.9
Gross margin (a)	$ 16.9	$ 3.8	$ 1.0	$ —	$ 21.7
Operating and maintenance expense	(3.9)	(2.1)	(0.3)	—	(6.3)
Depreciation and amortization expense	(3.8)	(0.2)	(0.5)	—	(4.5)
General and administrative expense	—	—	—	(6.9)	(6.9)
Earnings from equity method investments	—	—	0.3	—	0.3
Interest income	—	—	—	0.8	0.8
Interest expense	—	—	—	(4.6)	(4.6)
Net income (loss)	$ 9.2	$ 1.5	$ 0.5	$ (10.7)	$ 0.5
Capital expenditures	$ 2.3	$ 1.4	$ 0.5	$ —	$ 4.2

Three Months Ended June 30, 2006

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(b)	Total
Total operating revenues	$ 93.6	$ 65.1	$ 1.4	$ —	$ 160.1
Gross margin (a)	$ 18.2	$ 2.8	$ 1.1	$ —	$ 22.1
Operating and maintenance expense	(2.9)	(2.1)	(0.1)	—	(5.1)
Depreciation and amortization expense	(2.7)	(0.2)	(0.2)	—	(3.1)
General and administrative expense	—	—	—	(4.6)	(4.6)
Earnings from equity method investments	—	—	0.1	—	0.1
Interest income	—	—	—	1.5	1.5
Interest expense	—	—	—	(2.6)	(2.6)
Net income (loss)	$ 12.6	$ 0.5	$ 0.9	$ (5.7)	$ 8.3
Capital expenditures	$ 2.4	$ 4.0	$ 1.0	$ —	$ 7.4

Six Months Ended June 30, 2007

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(b)	Total
Total operating revenue	$ 196.4	$ 227.0	$ 3.6	$ —	$ 427.0
Gross margin (a)	$ 34.0	$ 14.6	$ 2.3	$ —	$ 50.9
Operating and maintenance expense	(7.2)	(5.3)	(0.4)	—	(12.9)
Depreciation and amortization expense	(6.7)	(0.4)	(0.8)	—	(7.9)
General and administrative expense	—	—	—	(11.7)	(11.7)
Earnings from equity method investments	—	—	0.5	—	0.5
Interest income	—	—	—	2.5	2.5
Interest expense	—	—	—	(8.4)	(8.4)
Net income (loss)	$ 20.1	$ 8.9	$ 1.6	$ (17.6)	$ 13.0
Capital expenditures	$ 4.1	$ 2.6	$ 0.9	$ —	$ 7.6

Six Months Ended June 30, 2006

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(b)	Total
Total operating revenues	$ 212.4	$ 210.5	$ 2.6	$ —	$425.5
Gross margin (a)	$ 35.2	$ 8.4	$ 2.0	$ —	$ 45.6
Operating and maintenance expense	(7.0)	(4.2)	(0.3)	—	(11.5)
Depreciation and amortization expense	(5.5)	(0.5)	(0.4)	—	(6.4)
General and administrative expense	—	—	—	(9.3)	(9.3)
Earnings from equity method investments	—	—	0.1	—	0.1
Interest income	—	—	—	3.0	3.0
Interest expense	—	—	—	(5.2)	(5.2)
Net income (loss)	$ 22.7	$ 3.7	$ 1.4	$ (11.5)	$ 16.3
Capital expenditures	$ 5.9	$ 5.2	$ 1.0	$ —	$ 12.1

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

	June 30, 2007	December 31, 2006
Segment long-term assets:		
Natural Gas Services (c)	$334.5	$ 147.4
Wholesale Propane Logistics	51.8	50.2
NGL Logistics	35.4	35.1
Other (d)	6.0	109.3
Total long-term assets	427.7	342.0
Current assets	159.3	159.6
Total assets	$587.0	$ 501.6

(a) Gross margin consists of total operating revenues less purchases of natural gas, propane and NGLs. Gross margin is viewed as a non-GAAP measure under the rules of the 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) Long-term assets for our Natural Gas Services segment increased as of June 30, 2007 as a result of our Southern Oklahoma asset acquisition of approximately $181.1 million in May 2007.

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

14. Subsequent Events

On July 25, 2007, the board of directors of the General Partner declared a quarterly distribution of $0.53 per unit, payable on August 14, 2007 to unitholders of record on August 7, 2007. This distribution of $0.53 per unit exceeds the Fourth Target Distribution level (see Note 8 for discussion of distributions of available cash).

On July 1, 2007, we acquired a 25% limited liability company interest in DCP East Texas Holdings, LLC, a 40% limited liability company interest in Discovery Producer Services LLC and a derivative instrument from DCP Midstream, LLC for aggregate consideration consisting of $244.7 million in cash, the issuance of 620,404 common units valued at $27.0 million and the issuance of 12,661 general partner equivalent units valued at $0.6 million. We financed the cash portion of this transaction with borrowings under our amended credit facility.

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. We will use the mark-to-market method of accounting for all commodity cash flow hedges beginning in July 2007. As a result, the remaining net loss of $2.0 million deferred in AOCI as of June 30, 2007 will be reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the hedged transactions impact earnings.

In August 2007, we entered into interest rate swap agreements to convert $200.0 million of the indebtedness on our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. All interest rate swaps commence on September 21, 2007, expire on June 21, 2012 and re-price prospectively approximately every 90 days. 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.

In August 2007, our Omnibus Agreement with DCP Midstream, LLC was amended to increase the annual fee by $0.6 million for general and administrative expenses payable to DCP Midstream, LLC under the agreement to account for additional services provided to us and extend the term for all general and administrative expenses under the agreement through December 31, 2009.

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 the consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2006, or 2006 Form 10-K.

Overview

We are a Delaware limited partnership formed by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We operate in three business segments:

- our Natural Gas Services segment, which consists of our Northern Louisiana natural gas gathering, processing and transportation system and the Southern Oklahoma system that was acquired in May 2007;
- our Wholesale Propane Logistics segment, which consists of six owned rail terminals, one leased marine terminal, one pipeline terminal, and access to several open access pipeline terminals; and
- our NGL Logistics segment, which consists of our interests in three NGL pipelines.

The financial information contained herein includes, for each period presented, our accounts, and the assets, liabilities and operations of our wholesale propane logistics business, which we acquired in November 2006 from DCP Midstream, LLC in a transaction among entities under common control.

Recent Events

In August 2007, our Omnibus Agreement with DCP Midstream, LLC was amended to increase the annual fee by $0.6 million for general and administrative expenses payable to DCP Midstream, LLC under the agreement to account for additional services provided to us and extend the term for all general and administrative expenses under the agreement through December 31, 2009.

In August 2007, we entered into interest rate swap agreements to convert $200.0 million of the indebtedness on our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. All interest rate swaps commence on September 21, 2007, expire on June 21, 2012 and re-price prospectively approximately every 90 days. 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.

On July 25, 2007, the board of directors of the General Partner declared a quarterly distribution of $0.53 per unit, payable on August 14, 2007 to unitholders of record on August 7, 2007. This distribution of $0.53 per unit exceeds the Fourth Target Distribution level (see Note 12 in our 2006 Form 10-K for discussion of distributions of available cash).

On July 1, 2007, we acquired a 25% limited liability company interest in DCP East Texas Holdings, LLC, a 40% limited liability company interest in Discovery Producer Services LLC and a derivative instrument from DCP Midstream, LLC for aggregate consideration consisting of $244.7 million in cash, the issuance of 620,404 common units valued at $27.0 million and the issuance of 12,661 general partner equivalent units valued at $0.6 million. We financed the cash portion of this transaction with borrowings under our credit facility, which was amended on June 22, 2007 as described below.

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. We will use the mark-to-market method of accounting for all commodity cash flow hedges beginning in July 2007. As a result, the remaining net loss of $2.0 million deferred in accumulated other comprehensive income as of June 30, 2007 will be reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the hedged transactions impact earnings.

On June 22, 2007, we entered into a private placement agreement with a group of institutional investors for $130.0 million, representing 3,005,780 common limited partner units at a price of $43.25 per unit, and received proceeds of $128.5 million, net of offering costs. We used a portion of the net proceeds of this private placement to pay down a portion of the debt associated with our Southern Oklahoma asset acquisition, and will use the remaining portion of the net proceeds to fund future capital expenditures including the Momentum Energy Group Inc., or MEG, acquisition described below. In connection with this private placement agreement, we entered into a registration rights agreement with institutional investors that requires us to file a shelf registration statement with the Securities and Exchange Commission, or SEC, to register the units by the earlier of within 120 days of the close of the private placement or when a shelf registration statement is filed to register the units to be issued in connection with the MEG acquisition described below. In addition the registration rights agreement requires us to use our commercially reasonable efforts to cause the registration statement to become effective within 210 days of the closing of the private placement, or we will be liable to the institutional investors for liquidated damages of 0.25% of the product of the purchase price times the number of registrable securities held by the institutional investors per 30-day period for the first 60 days following the 210th day, increasing by an additional 0.25% of the product of the purchase price times the number of registrable securities held by the institutional investors per 30-day period for each subsequent 60 days, up to a maximum of 1.00% of the product of the purchase price times the number of registrable securities held by the institutional investors per 30-day period.

On June 21, 2007, we entered into an Amended and Restated Credit Agreement, or the Amended Credit Agreement, which amended our existing credit agreement, or the Credit Agreement. This new 5-year Amended Credit Agreement consists of a $600.0 million revolving credit facility and a $250.0 million term loan facility, and matures on June 21, 2012. The amendment also improved pricing and certain other terms or conditions of the Credit Agreement. See the Liquidity and Capital Resources—Description of Amended Credit Agreement section below for additional information.

In June 2007, we executed a series of financial derivatives to mitigate a portion of the commodity price exposure associated with our Northern Louisiana system assets. We entered into crude oil swap contracts for 250 Bbls/d at $71.35/Bbl for 2011, 600 Bbls/d at $71.00/Bbl for 2012 and 600 Bbls/d at $71.20/Bbl for 2013.

In May 2007, we agreed to acquire certain subsidiaries of MEG from DCP Midstream, LLC for $165.0 million, subject to closing adjustments. This transaction is expected to close in the third quarter of 2007, but is contingent upon DCP Midstream, LLC closing their acquisition of the stock of MEG. The subsidiaries we intend to acquire include assets in the Piceance Basin, including a 70% operated interest in the 31-mile Collbran Valley Gas Gathering system joint venture in western Colorado, assets in the Powder River Basin, including a 1,324-mile Douglas gas gathering system, and other facilities in Wyoming. We plan to finance this transaction with a $100.0 million private placement of common limited partner units described below, $32.0 million of the net proceeds from the June private placement, the issuance of 275,735 common limited partner units to DCP Midstream valued at approximately $12.0 million, $20.0 million in borrowings under our credit facility and approximately $1.0 million of available cash. On May 21, 2007, in connection with this acquisition, we entered into a common unit purchase agreement, which is contingent on the closing of the MEG acquisition, with certain institutional investors to sell 2,380,952 common limited partner units in a private placement at $42.00 per unit, or approximately $100.0 million in the aggregate. In connection with this common unit purchase agreement, we have a registration obligation that is contingent upon closing of the MEG acquisition.

In May 2007, we acquired certain gathering and compression assets located in Southern Oklahoma, as well as related commodity purchase contracts, from Anadarko Petroleum Corporation, for approximately $181.1 million, subject to customary purchase price adjustments. In April 2007, we acquired certain gathering and compression assets located in northern Louisiana for approximately $10.2 million, subject to customary purchase price adjustments. The results of operations from these acquired assets are included in our Natural Gas Services segment, prospectively from the dates of acquisition.

In May 2007, we executed a series of financial derivatives to mitigate a portion of the commodity exposure associated with the Southern Oklahoma asset acquisition. We entered into natural gas swap contracts for 1,500 MMBtu/d at $7.54 per MMBtu and into crude oil swap contracts for 650 Bls/d at $67.60 per Bbl for a term from June 2007 through December 2013.

In May 2007, we entered into a two-month bridge loan, or the Bridge Loan, which provided for borrowings of up to $100.0 million, and had terms and conditions substantially similar to those of our Credit Agreement. In conjunction with our entering into the Bridge Loan, our Credit Agreement was amended to provide for additional unsecured indebtedness, of an amount not to exceed $100.0 million, which was due and payable no later than August 9, 2007. We used borrowings on the Bridge Loan of $88.0 million to partially fund the Southern Oklahoma asset acquisition. The remaining $12.0 million available for borrowing on the Bridge Loan was not utilized. We used a portion of the net proceeds of a private placement of limited partner units to extinguish the $88.0 million outstanding on the Bridge Loan.

In April 2007, we filed with the Securities and Exchange Commission a universal shelf registration statement on Form S-3 with a maximum aggregate offering price of $1.5 billion, which will, upon effectiveness, allow us to register and issue additional partnership units and debt obligations.

Factors That Significantly Affect Our Results

Our 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 contract arrangements can have a significant impact on our profitability. Because of the volatility of the prices for natural gas, NGLs and condensate, we have mitigated a significant portion of our anticipated commodity price risk associated with our gathering and processing arrangements through 2013 with natural gas and 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. We will continue to have direct commodity price risk associated with the remainder of our natural gas supply, and production of NGLs and condensate from our processing plants. For additional information regarding our derivative activities, please read "— Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk — Hedging Strategies" in our 2006 Form 10-K. 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.

In December 2006, the Pelico system filed a new Section 311 rate case with the Federal Energy Regulatory Commission. The settlement in the rate case, which was approved on April 25, 2007, provided for an increase in the maximum transportation rate that the Pelico system can charge, to $0.2322 per MMBtu from $0.1965 per MMBtu, effective December 1, 2006. There were no other changes to the Pelico system's terms and conditions of service.

Our results of operations for our Natural Gas Services segment are impacted by market conditions causing variability in natural gas prices. In the past, we have benefited from marketing activities and increased throughput related to atypical and significant differences in natural gas prices at various receipt and delivery points on our Pelico intrastate pipeline system. The market conditions causing the variability 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.

Our results of operations for our Wholesale Propane Logistics segment are impacted by our ability to balance our purchases and sales of propane, which may increase our exposure to commodity price risks, and by the impact on volume and pricing from weather conditions in the Midwest and northeastern sections of the United States. Our sales of propane may decline when these areas experience periods of milder weather in the winter months, which is when the demand for propane is generally at its highest.

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

In November, 2006 we acquired our wholesale propane logistics business from DCP Midstream, LLC in a transaction among entities under common control. Accordingly, our financial information includes the historical results of our wholesale propane logistics business for each period presented. Prior to November 2006, our financial statements do not give effect to various items that affected our results of operations and liquidity following the acquisition of our wholesale propane logistics business, including the indebtedness we incurred in conjunction with the closing of the acquisition of our wholesale propane logistics business, which increased our interest expense from the interest expense reflected in our historical financial statements.

We completed pipeline integrity testing during 2006, resulting in increased operating costs on Seabreeze, one of our NGL transportation pipelines. The construction of Wilbreeze, an NGL transportation pipeline connecting a DCP Midstream, LLC gas processing plant to the Seabreeze pipeline, was completed in December 2006. The Black Lake pipeline is currently experiencing increased operating costs due to pipeline integrity testing that commenced in 2005 and has continued into 2007. We expect that our results of operations related to our equity interest in the Black Lake pipeline 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. DCP Midstream, LLC 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. Pipeline integrity testing and repairs are our responsibility and are recognized as operating and maintenance expense. Any reimbursement of these expenses from DCP Midstream, LLC will be recognized by us as a capital contribution. Seabreeze pipeline integrity testing was completed in 2006 and reimbursements related to these repairs were not significant.

During 2006, we entered into agreements with ConocoPhillips, which expanded the gathering and transportation services between us. As a result of these agreements, nine new wells were added during the six months ended June 30, 2007, and 17 new wells were added to our system during 2006.

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.

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, our Wholesale Propane Logistics 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 margin for our Natural Gas Services segment principally under percentage-of-proceeds arrangements and fee-based arrangements, as described in “Critical Accounting Policies and Estimates — Revenue Recognition” in our 2006 Form 10-K.

We have mitigated a significant portion of our currently anticipated natural gas and NGL commodity price risk associated with the percentage-of-proceeds arrangements through 2013 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. We have mitigated a significant portion of our condensate price risk through 2013 with crude oil swaps. For additional information regarding our derivative activities, please read “— Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk — Hedging Strategies” in our 2006 Form 10-K and “Item 3. Quantitative and Qualitative Disclosures about Market Risk” in this Quarterly Report on Form 10-Q.

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. We will use the mark-to-market method of accounting for all commodity cash flow hedges, which is expected to significantly increase the volatility of our results of operations as we will recognize, in current earnings, all non-cash gains and losses from the mark-to-market on non-trading derivative activity.

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 Northern Louisiana system is derived primarily from natural gas wells located in five parishes in northern Louisiana, and in our Southern Oklahoma system is derived primarily from natural gas wells located in three counties in southern Oklahoma. The Pelico system receives natural gas produced in eastern Texas through its interconnect with other pipelines that transport natural gas from eastern Texas into western Louisiana. These areas have experienced significant levels of drilling activity, providing us with opportunities to access newly developed natural gas supplies. We identify primary suppliers as those individually representing 10% or more of our total natural gas supply. Our primary suppliers of natural gas to the Northern Louisiana and Southern Oklahoma systems represented approximately 64% of the 325 MMcf/d of natural gas supplied to this system in the six months ended June 30, 2007. 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, 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 DCP Midstream, LLC 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 DCP Midstream, LLC that provides that DCP Midstream, LLC will purchase natural gas and transport it into our Pelico system, where we will buy the gas from DCP Midstream, LLC at the actual acquisition cost plus transportation service charges incurred. In addition, for a significant portion of the gas that we sell out of our Pelico system, we have entered into a contractual arrangement with DCP Midstream, LLC that provides that DCP Midstream, LLC will purchase that natural gas from us and transport it to a sales point at a price equal to their net weighted-average sales price less a contractually agreed-to marketing fee. 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 occasionally will enter into financial derivatives to lock in price variability across the Pelico system to maximize the value of pipeline capacity. 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 DCP Midstream, LLC 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 affiliates. The NGLs extracted from a third party that is processing natural gas in the Southern Oklahoma system are sold to third parties at market index prices.

Wholesale Propane Logistics Segment

We operate a wholesale propane logistics business in the Midwest and northeastern United States. We purchase large volumes of propane supply from natural gas processing plants and fractionation facilities, and crude oil refineries, primarily located in the Texas and Louisiana Gulf Coast area, Canada and other international sources, and transport these volumes of propane supply by pipeline, rail or ship to our terminals and storage facilities in the Midwest and the northeastern areas of the United States. We identify primary suppliers as those individually representing 10% or more of our total propane supply. Our primary suppliers of propane represented approximately 81% of our propane purchases in the six months ended June 30, 2007.We sell propane on a wholesale basis to retail propane distributors who in turn resell propane to their retail customers.

Due to our multiple propane supply sources, long-term propane supply purchase arrangements, significant storage capabilities, and multiple terminal locations for wholesale propane delivery, we are generally able to provide our retail propane distribution customers with reliable deliveries of propane during periods of tight supply, such as the winter months when their retail customers consume the most propane for home heating. In particular, we generally offer our customers the ability to obtain propane supply volumes from us in the winter months that are significantly greater than their purchase of propane from us in the summer. We believe these factors generally allow us to maintain our favorable relationship with our customers.

We manage our wholesale propane margins by selling propane to retail propane distributors under annual sales agreements negotiated each spring that specify floating price terms that provide us a margin in excess of our floating index-based supply costs under our supply purchase arrangements. In the event that a retail propane distributor desires to purchase propane from us on a fixed price basis, we sometimes enter into fixed price sales agreements with terms of generally up to one year, and we manage this commodity price risk by entering into either offsetting physical purchase agreements or financial derivative instruments, with either DCP Midstream, LLC or third parties, that generally match the quantities of propane subject to these fixed price sales agreements. Our portfolio of multiple supply sources and storage capabilities allows us to actively manage our propane supply purchases and to lower the aggregate cost of supplies. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories.

NGL Logistics Segment

Our pipelines provide transportation services to customers on a fee basis. We have entered into contractual arrangements with DCP Midstream, LLC that require DCP Midstream, LLC to pay us to transport the NGLs pursuant to a fee-based rate that is applied to the volumes transported. 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 do 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 and Wilbreeze pipelines, 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 NGLs extracted 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 not accounting principles generally accepted in the United States of America, or GAAP, financial measures. We provide reconciliations of these non-GAAP measures to their most directly comparable financial measures as calculated and presented in accordance with GAAP. Our gross margin, segment gross margin, EBITDA and distributable cash flow may not be comparable to a similarly titled measure of another company because other entities may not calculate these non-GAAP measures in the same manner.

Volumes — We view throughput volumes for our Natural Gas Services segment and our NGL Logistics segment, and sales volumes for our Wholesale Propane Logistics segment as important factors 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 our 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 pipelines 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 our NGL pipelines. We regularly monitor producer activity in the areas we serve and our 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, propane and NGLs, and we define segment gross margin for each segment as total operating revenues for that segment less commodity purchases 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 natural gas and NGL purchases. 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 from our non-trading derivative activity. 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 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 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. The following table sets forth our reconciliation of certain non-GAAP measures ($ in millions):

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Reconciliation of Non-GAAP Measures				
Reconciliation of net income to gross margin:				
Net income	$ 0.5	$ 8.3	$ 13.0	$ 16.3
Add:				
Interest expense	4.6	2.6	8.4	5.2
Operating and maintenance expense	6.3	5.1	12.9	11.5
Depreciation and amortization expense	4.5	3.1	7.9	6.4
General and administrative expense	6.9	4.6	11.7	9.3
Less:				
Interest income	(0.8)	(1.5)	(2.5)	(3.0)
Earnings from equity method investments	(0.3)	(0.1)	(0.5)	(0.1)
Gross margin	$ 21.7	$ 22.1	$ 50.9	$ 45.6
Reconciliation of segment net income to segment gross margin:				
Natural Gas Services segment:				
Segment net income	$ 9.2	$ 12.6	$ 20.1	$ 22.7
Add:				
Depreciation and amortization expense	3.8	2.7	6.7	5.5
Operating and maintenance expense	3.9	2.9	7.2	7.0
Segment gross margin	$ 16.9	$ 18.2	$ 34.0	$ 35.2
Wholesale Propane Logistics segment:				
Segment net income	$ 1.5	$ 0.5	$ 8.9	$ 3.7
Add:				
Depreciation and amortization expense	0.2	0.2	0.4	0.5
Operating and maintenance expense	2.1	2.1	5.3	4.2
Segment gross margin	$ 3.8	2.8	$ 14.6	8.4
NGL Logistics segment:				
Segment net income	$ 0.5	$ 0.9	$ 1.6	$ 1.4
Add:				
Depreciation and amortization expense	0.5	0.2	0.8	0.4
Operating and maintenance expense	0.3	0.1	0.4	0.3
Less: Earnings from equity method investments	(0.3)	(0.1)	(0.5)	(0.1)
Segment gross margin	$ 1.0	$ 1.1	$ 2.3	$ 2.0

Operating and Maintenance and General and Administrative Expense — Operating and maintenance expense are costs associated with the operation of a specific asset. Direct labor, ad valorem taxes, repairs and maintenance, lease expenses, 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 DCP Midstream, LLC. For the three months ended June 30, 2007 and 2006, our general and administrative expense was $6.9 million and $4.6 million, respectively. For the six months ended June 30, 2007 and 2006, our general and administrative expense was $11.7 million and $9.3 million, respectively. We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee for centralized corporate functions performed by DCP Midstream, LLC 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. The Omnibus Agreement: (1) states that the annual fee of $4.8 million for the initial assets under the agreement was fixed at such amount for 2006, subject to annual increases in the Consumer Price Index, which increased to $5.0 million for 2007; (2) effective November 2006, includes an additional annual fee of $2.0 million related to the acquisition of our wholesale propane logistics business from DCP Midstream, LLC, subject to the same conditions noted above; (3) effective May 2007, includes an additional annual fee of

$0.2 million related to the Southern Oklahoma asset acquisition, subject to the same conditions noted above; (4) effective July 2007, includes an additional annual fee of $0.1 million related to the acquisition of the 40% limited liability company interest in Discovery Producer Services LLC from DCP Midstream, LLC, subject to the same conditions noted above; and (5) effective August 2007, includes an additional fee of $0.6 million to account for additional services provided to us.

We incurred approximately $5.1 million and $8.2 million, and $3.4 million and $6.9 million, of other general and administrative expense during the three and six months ended June 30, 2007 and 2006, respectively, primarily relating to compensation and benefit expenses of the personnel who provide direct support to our operations. Also included are expenses associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, due diligence and acquisition costs, 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. These incremental expenses exclude $1.8 million and $3.5 million, and $1.2 million and $2.4 million, for the three and six ended June 30, 2007 and 2006, respectively, per the Omnibus Agreement, for other various general and administrative services.

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 Amended Credit Agreement) of not more than 5.75 to 1.0 through and including the quarter ended June 30, 2007 and 5.0 to 1.0 thereafter, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of asset acquisitions in the midstream energy business, of not more than 5.50 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 Amended Credit Agreement) of equal or greater than 2.5 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 net cash provided by operating activities, less maintenance capital expenditures, net of reimbursable projects, plus or minus adjustments for non-cash hedge ineffectiveness, non-cash mark-to-market of derivative instruments, net changes in operating assets and liabilities, and other adjustments to reconcile net cash provided by or used in operating activities (see "— Liquidity and Capital Resources" below for further definition of maintenance capital expenditures). In 2006, we also adjusted distributable cash flow for a post-closing reimbursement from DCP Midstream, LLC for maintenance capital expenditures. Maintenance capital expenditures are capital expenditures made 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. 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 flow 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 others, to assess our ability to make cash distributions to our unitholders and our general partner. Our distributable cash flow may not be comparable to a similarly titled measure of another company because other entities may not calculate distributable cash flow in the same manner. The following table sets forth our reconciliation of certain non-GAAP measures ($ in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Reconciliation of Non-GAAP Measures				
Reconciliation of net income to EBITDA:				
Net income	$ 0.5	$ 8.3	$ 13.0	$ 16.3
Interest income	(0.8)	(1.5)	(2.5)	(3.0)
Interest expense	4.6	2.6	8.4	5.2
Depreciation and amortization expense	4.5	3.1	7.9	6.4
EBITDA	$ 8.8	$ 12.5	$ 26.8	$ 24.9
Reconciliation of net cash provided by operating activities to EBITDA:				
Net cash provided by operating activities	$ 7.1	$ 18.7	$ 21.3	$ 26.9
Interest income	(0.8)	(1.5)	(2.5)	(3.0)
Interest expense	4.6	2.6	8.4	5.2
Undistributed earnings from equity method investments	0.3	0.1	0.5	0.1
Net changes in operating assets and liabilities	(2.3)	(8.1)	(1.3)	(5.7)
Other, net	(0.1)	0.7	0.4	1.4
EBITDA	$ 8.8	$ 12.5	$ 26.8	$ 24.9

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are described in Item 7 in our 2006 Form 10-K. The accounting policies and estimates used in preparing our interim condensed consolidated financial statements for the three and six months ended June 30, 2007 are the same as those described in our 2006 Form 10-K.

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three and six months ended June 30, 2007 and 2006. The results of operations by segment are discussed in further detail following this consolidated overview discussion ($ in millions, except operating data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Operating revenues:				
Natural Gas Services	$ 110.0	$ 93.6	$ 196.4	$ 212.4
Wholesale Propane Logistics	75.2	65.1	227.0	210.5
NGL Logistics	1.7	1.4	3.6	2.6
Total operating revenues	186.9	160.1	427.0	425.5
Gross margin (a):				
Natural Gas Services	16.9	18.2	34.0	35.2
Wholesale Propane Logistics	3.8	2.8	14.6	8.4
NGL Logistics	1.0	1.1	2.3	2.0
Total gross margin	21.7	22.1	50.9	45.6
Operating and maintenance expense	6.3	5.1	12.9	11.5
General and administrative expense	6.9	4.6	11.7	9.3
Earnings from equity method investments (b)	(0.3)	(0.1)	(0.5)	(0.1)
EBITDA (c)	8.8	12.5	26.8	24.9
Depreciation and amortization expense	4.5	3.1	7.9	6.4
Interest income	(0.8)	(1.5)	(2.5)	(3.0)
Interest expense	4.6	2.6	8.4	5.2
Net income	$ 0.5	$ 8.3	$ 13.0	$ 16.3
Operating data:				
Natural gas throughput (MMcf/d)	373	386	372	375
NGL gross production (Bbls/d)	6,620	5,320	5,962	5,141
Propane sales volume (Bbls/d)	16,179	14,837	25,715	24,664
NGL pipelines throughput (Bbls/d) (b)	28,376	24,469	27,917	23,947

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

(b) Includes 45% of the throughput volumes and earnings of Black Lake.

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

Three Months Ended June 30, 2007 vs. Three Months Ended June 30, 2006

Total Operating Revenues — Total operating revenues increased $26.8 million, or 17%, to $186.9 million in 2007 from $160.1 million in 2006, primarily due to the following:

- $21.7 million increase attributable primarily to higher commodity prices and an increase in natural gas, NGL and condensate sales volumes, including increases as a result of the Southern Oklahoma asset acquisition, for our Natural Gas Services segment;
- $10.1 million increase attributable to higher propane sales volumes and prices for our Wholesale Propane Logistics segment;

- $0.6 million increase in transportation and processing services revenue, primarily attributable to an increase in volumes in our Natural Gas Services segment; and
- $0.2 million increase due to an increase in NGL sales for our NGL Logistics segment; offset by
- $5.8 million decrease related to commodity hedging and non-trading derivative activity.

Gross Margin — Gross margin decreased $0.4 million, or 2%, to $21.7 million in 2007 from $22.1 million in 2006, primarily due to the following:

- $1.3 million decrease for our Natural Gas Services segment primarily due to decreases related to commodity hedging and non-trading derivative activity, offset by higher NGL and condensate production, as a result of the Southern Oklahoma asset acquisition; and
- $0.1 million decrease attributable to lower per unit margins as a result of changes in product mix at various receipt points, offset by higher throughput volumes for our NGL Logistics segment; offset by
- $1.0 million increase due to higher sales volumes and higher per unit margins as a result of changes in contract mix and the ability to capture lower priced supply sources for our Wholesale Propane Logistics segment,

Operating and Maintenance Expense — Operating and maintenance expense increased $1.2 million, or 24%, to $6.3 million in 2007 from $5.1 million in 2006, primarily as a result of higher labor and benefits, pipeline integrity costs and higher expenses as a result of the Southern Oklahoma asset acquisition in our Natural Gas Services segment and higher expenses as a result of the addition of our Wilbreeze pipeline in December 2006 in our NGL Logistics segment.

General and Administrative Expense — General and administrative expense increased $2.3 million, or 50%, to $6.9 million in 2007 from $4.6 million in 2006, primarily as a result of increased due diligence and acquisition costs, audit and legal fees, and labor and benefit costs.

Earnings from Equity Method Investments — Earnings from equity method investments increased to $0.3 million in 2007 from $0.1 million in 2006. This increase was as a result of higher transport volumes on our Black Lake pipeline.

Depreciation and Amortization Expense — Depreciation and amortization expense increased $1.4 million, or 45%, to $4.5 million in 2007 from $3.1 million in 2006, primarily as a result of asset acquisitions.

Six Months Ended June 30, 2007 vs. Six Months Ended June 30, 2006

Total Operating Revenues — Total operating revenues increased $1.5 million, or less than 1%, to $427.0 million in 2007 from $425.5 million in 2006, primarily due to the following:

- $16.7 million increase attributable to higher propane sales volumes and prices for our Wholesale Propane Logistics segment;
- $1.4 million increase in transportation and processing services revenue, primarily attributable to an increase in volumes in our Natural Gas Services segment; and
- $0.6 million increase due to an increase in NGL sales as well as the composition of inventory transactions at receipt versus delivery points for our NGL Logistics segment; offset by
- $13.1 million decrease attributable primarily to a decrease in commodity prices as well as a decrease in natural gas sales volumes, primarily as a result of an amendment to a contract with an affiliate in 2006, which resulted in a prospective change in the reporting of certain Pelico revenues from a gross presentation to a net presentation, offset by an increase in natural gas, NGL and condensate sales volumes as a result of the Southern Oklahoma asset acquisition in our Natural Gas Services segment; and
- $4.1 million decrease related to commodity hedging and non-trading derivative activity.

Gross Margin — Gross margin increased $5.3 million, or 12%, to $50.9 million in 2007 from $45.6 million in 2006, primarily due to the following:

- $6.2 million increase due to higher sales volumes, higher per unit margins as a result of changes in contract mix and the ability to capture lower priced supply sources, and non-cash lower of cost or market inventory adjustments for our Wholesale Propane Logistics segment; and

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- $0.3 million increase attributable to increased transportation revenue and volumes for our NGL Logistics segment as a result of the addition of our Wilbreeze pipeline in December 2006; offset by
- $1.2 million decrease for our Natural Gas Services segment primarily due to decreases related to commodity hedging and non-trading derivative activity, a decrease in marketing margins from the decline in the differences in natural gas prices at various receipt and delivery points across our Pelico system, and lower natural gas prices, offset by higher NGL and condensate production as a result of the Southern Oklahoma asset acquisition.

Operating and Maintenance Expense — Operating and maintenance expense increased $1.4 million, or 12%, to $12.9 million in 2007 from $11.5 million in 2006, primarily as a result of higher operating and maintenance expense at the new Midland terminal, which became operational in May 2007, and higher labor and benefit costs in our Wholesale Propane Logistics segment, and as a result of the Southern Oklahoma asset acquisition in our Natural Gas Services segment.

General and Administrative Expense — General and administrative expense increased $2.4 million, or 26%, to $11.7 million in 2007 from $9.3 million in 2006, primarily as a result of increased due diligence and acquisition costs, audit and legal fees, and labor and benefit costs.

Earnings from Equity Method Investments — Earnings from equity method investments increased to $0.5 million in 2007 from $0.1 million in 2006. This increase was as a result of higher transport volumes and reduced operating expenses on our Black Lake pipeline.

Depreciation and Amortization Expense — Depreciation and amortization expense increased $1.5 million, or 23%, to $7.9 million in 2007 from $6.4 million in 2006, primarily as a result of asset acquisitions.

Results of Operations — Natural Gas Services Segment

This segment consists of our Northern Louisiana system and the Southern Oklahoma system that was acquired in May 2007 ($ in millions, except operating data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Operating revenues:				
Sales of natural gas, NGLs and condensate	$ 109.5	$ 87.8	$ 189.7	$ 201.1
Transportation and processing services	6.3	5.8	12.3	11.3
Losses from non-trading derivative activity	(5.8)	—	(5.6)	—
Total operating revenues	110.0	93.6	196.4	212.4
Purchases of natural gas and NGLs	93.1	75.4	162.4	177.2
Segment gross margin (a)	16.9	18.2	34.0	35.2
Operating and maintenance expense	3.9	2.9	7.2	7.0
Depreciation and amortization expense	3.8	2.7	6.7	5.5
Segment net income	$ 9.2	$ 12.6	$ 20.1	$ 22.7
Operating data:				
Natural gas throughput (MMcf/d)	373	386	372	375
NGL gross production (Bbls/d)	6,620	5,320	5,962	5,141

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

Three Months Ended June 30, 2007 vs. Three Months Ended June 30, 2006

Total Operating Revenues — Total operating revenues increased $16.4 million, or 18%, to $110.0 million in 2007 from $93.6 million in 2006, primarily due to the following:

- $12.1 million increase primarily attributable to higher natural gas, NGL and condensate sales volumes, partially as a result of the Southern Oklahoma asset acquisition;
- $9.6 million increase attributable to an increase in commodity prices; and
- $0.5 million increase in transportation and processing services revenue; offset by

- $5.8 million decrease related to commodity hedging and non-trading derivative activity.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs increased $17.7 million, or 23%, to $93.1 million in 2007 from $75.4 million in 2006, primarily due to higher costs of raw natural gas supply, driven by higher commodity prices as well as increased natural gas purchase volumes, partially as a result of the Southern Oklahoma asset acquisition.

Segment Gross Margin — Segment gross margin decreased $1.3 million, or 7%, to $16.9 million in 2007 from $18.2 million in 2006, primarily as a result of the following:

- $5.8 million decrease related to commodity hedging and non-trading derivative activity; offset by
- $3.9 million increase primarily attributable to an increase in NGL and condensate production, mainly as a result of the Southern Oklahoma asset acquisition; and
- $0.6 million increase primarily attributable to higher contractual fees charged to customers.

Operating and Maintenance Expense — Operating and maintenance expense increased $1.0 million, or 34%, to $3.9 million in 2007 from $2.9 million in 2006, primarily as a result of higher labor and benefits and pipeline integrity costs and the Southern Oklahoma asset acquisition.

NGL production during 2007 increased 1,300 Bbls/d, or 24%, to 6,620 Bbls/d from 5,320 Bbls/d in 2006, due primarily to an increase in volumes from the Southern Oklahoma asset acquisition in May 2007. Natural gas transported and/or processed during 2007 decreased 13 MMcf/d, or 3%, to 373 MMcf/d from 386 MMcf/d in 2006.

Six Months Ended June 30, 2007 vs. Six Months Ended June 30, 2006

Total Operating Revenues — Total operating revenues decreased $16.0 million, or 8%, to $196.4 million in 2007 from $212.4 million in 2006, primarily due to the following:

- $7.4 million decrease attributable to a decrease in commodity prices;
- $5.7 million decrease attributable to a decrease in natural gas sales volumes, primarily as a result of an amendment to a contract with an affiliate in 2006, which resulted in a prospective change in the reporting of certain Pelico revenues from a gross presentation to a net presentation, offset by an increase in natural gas, NGL and condensate sales volumes in the second quarter of 2007 partially as a result of the Southern Oklahoma asset acquisition; and
- $3.9 million decrease related to commodity hedging and non-trading derivative activity; offset by
- $1.0 million increase in transportation and processing services revenue primarily attributable to an increase in natural gas throughput.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs decreased $14.8 million, or 8%, to $162.4 million in 2007 from $177.2 million in 2006, primarily due to lower natural gas prices and decreased natural gas purchase volumes, primarily as a result of an amendment to a contract with an affiliate in 2006, which resulted in a prospective change in the reporting of certain Pelico purchases from a gross presentation to a net presentation, offset by increased natural gas purchase volumes partially as a result of the Southern Oklahoma asset acquisition.

Segment Gross Margin — Segment gross margin decreased $1.2 million, or 3%, to $34.0 million in 2007 from $35.2 million in 2006, primarily as a result of the following:

- $3.9 million decrease related to commodity hedging and non-trading derivative activity;
- $2.5 million decrease attributable primarily to a decrease in marketing margins from the decline in the differences in natural gas prices at various receipt and delivery points across our Pelico system, which were atypically high in 2006. The market conditions causing the variability 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;
- $0.9 million decrease primarily attributable to lower natural gas prices, partially offset by favorable frac spreads. The favorable frac spreads may not continue in the future; and
- $0.1 million decrease primarily attributable to a change in contract mix; offset by

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- $5.6 million increase primarily attributable to an increase in NGL and condensate production, partially as a result of the Southern Oklahoma asset acquisition, and an increase in natural gas throughput volumes; and
- $0.6 million increase primarily attributable to higher contractual fees charged to customers.

Operating and Maintenance Expense — Operating and maintenance expense increased $0.2 million, or 3%, to $7.2 million in 2007 from $7.0 million in 2006, primarily as a result of the Southern Oklahoma asset acquisition.

NGL production during 2007 increased 821 Bbls/d, or 16%, to 5,962 Bbls/d from 5,141 Bbls/d in 2006, due primarily to an increase in volumes from the Southern Oklahoma asset acquisition in May 2007, and an increase of gas volumes at our Minden processing plant in 2007. Natural gas transported and/or processed during 2007 decreased 3 MMcf/d, or 1%, to 372 MMcf/d from 375 MMcf/d in 2006.

Results of Operations — Wholesale Propane Logistics Segment

This segment includes our propane transportation facilities, which includes six owned rail terminals, one leased marine terminal, one pipeline terminal, and access to several open access pipeline terminals ($ in millions, except operating data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Operating revenues:				
Sales of propane	$ 75.6	$ 65.5	$ 227.7	$ 211.0
Losses from non-trading derivative activity	(0.4)	(0.4)	(0.7)	(0.5)
Total operating revenues	75.2	65.1	227.0	210.5
Purchases of propane	71.4	62.3	212.4	202.1
Segment gross margin (a)	3.8	2.8	14.6	8.4
Operating and maintenance expense	2.1	2.1	5.3	4.2
Depreciation and amortization expense	0.2	0.2	0.4	0.5
Segment net income	$ 1.5	$ 0.5	$ 8.9	$ 3.7
Operating data:				
Propane sales volume (Bbls/d)	16,179	14,837	25,715	24,664

(a) Segment gross margin consists of total operating revenues less purchases of propane. Please read “How We Evaluate Our Operations” above.

Three Months Ended June 30, 2007 vs. Three Months Ended June 30, 2006

Total Operating Revenues — Total operating revenues increased $10.1 million, or 16%, to $75.2 million in 2007 from $65.1 million in 2006, primarily due to the following:

- $7.2 million increase attributable to higher propane sales volumes as a result of milder weather in the northeastern United States in 2006 and the completion of the new Midland terminal in May 2007; and
- $2.9 million increase attributable to higher propane prices.

Purchases of Propane — Purchases of propane increased $9.1 million, or 15%, to $71.4 million in 2007 from $62.3 million 2006, primarily due to increased purchased volumes and prices, primarily due to milder weather in the northeastern United States in 2006, as well as increased purchased volumes due to the completion of the new Midland terminal in May 2007.

Segment Gross Margin — Segment gross margin increased $1.0 million, or 36%, to $3.8 million in 2007 from $2.8 million in 2006, primarily as a result of higher sales volumes and higher per unit margins as a result of changes in contract mix and the ability to capture lower priced supply sources.

Operating and Maintenance Expense — Operating and maintenance expense remained constant in 2007 and 2006.

Propane sales increased 1,342 Bbls/d, or 9%, to 16,179 Bbls/d in 2007 from 14,837 Bbls/d in 2006, due primarily to milder weather in the northeastern United States in 2006.

Six Months Ended June 30, 2007 vs. Six Months Ended June 30, 2006

Total Operating Revenues — Total operating revenues increased $16.5 million, or 8%, to $227.0 million in 2007 from $210.5 million in 2006, primarily due to the following:

- $10.4 million increase attributable to higher propane sales volumes as a result of milder weather in the northeastern United States in 2006 and the completion of the new Midland terminal in May 2007; and
- $6.3 million increase attributable to higher propane prices; offset by
- $0.2 million decrease related to non-trading derivative activity.

Purchases of Propane — Purchases of propane increased $10.3 million, or 5%, to $212.4 million in 2007 from $202.1 million 2006, primarily due to increased purchased volumes and prices, primarily due to milder weather in the northeastern United States in 2006 and the completion of the new Midland terminal in May 2007, offset by non-cash lower of cost or market inventory adjustments.

Segment Gross Margin — Segment gross margin increased $6.2 million, or 74%, to $14.6 million in 2007 from $8.4 million in 2006, primarily as a result of higher sales volumes, higher per unit margins as a result of changes in contract mix and the ability to capture lower priced supply sources, and non-cash lower of cost or market inventory adjustments.

Operating and Maintenance Expense — Operating and maintenance expense increased $1.1 million, or 26%, to $5.3 million in 2007 from $4.2 million in 2006, primarily as a result of higher operating and maintenance expense at the new Midland terminal, which became operational in May 2007, and higher labor and benefit costs.

Propane sales increased 1,051 Bbls/d, or 4%, to 25,715 Bbls/d in 2007 from 24,664 Bbls/d in 2006, due primarily to milder weather in the northeastern United States in 2006.

Results of Operations — NGL Logistics Segment

This segment includes our NGL transportation pipelines, which includes our Seabreeze and Wilbreeze pipelines, and our 45% interest in Black Lake ($ in millions, except operating data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Operating revenues:				
Sales of NGLs	$ 0.5	$ 0.3	$ 1.1	$ 0.5
Transportation and processing services	1.2	1.1	2.5	2.1
Total operating revenues	1.7	1.4	3.6	2.6
Purchases of NGLs	0.7	0.3	1.3	0.6
Segment gross margin (a)	1.0	1.1	2.3	2.0
Operating and maintenance expense	0.3	0.1	0.4	0.3
Earnings from equity method investment (b)	(0.3)	(0.1)	(0.5)	(0.1)
Depreciation and amortization expense	0.5	0.2	0.8	0.4
Segment net income	$ 0.5	$ 0.9	$ 1.6	$ 1.4
Operating data:				
NGL pipelines throughput (Bbls/d) (b)	28,376	24,469	27,917	23,947

(a) Segment gross margin consists of total operating revenues less purchases of natural gas and NGLs. Please read “How We Evaluate Our Operations” above.
(b) Includes 45% of the throughput volumes and earnings of Black Lake.

Three Months Ended June 30, 2007 vs. Three Months Ended June 30, 2006

Total Operating Revenues — Total operating revenues increased $0.3 million, or 21%, to $1.7 million in 2007 from $1.4 million in 2006, primarily due to an increase in revenues attributable to an increase in volumes, as well as the composition of inventory transactions at receipt versus delivery points.

Overall, our NGL pipelines experienced an increase in throughput volumes during 2007 as compared to 2006, primarily as a result of the addition of our Wilbreeze pipeline in December 2006.

Purchases of NGLs — Purchases of NGLs increased $0.4 million, or 133%, to $0.7 million in 2007 from $0.3 million in 2006, primarily due to an increase in purchases attributable to an increase in volumes, as well as the composition of inventory transactions at receipt versus delivery points.

Segment Gross Margin — Segment gross margin remained relatively constant in 2007 and 2006, but was impacted by lower per unit margins as a result of changes in product mix at various receipt points, offset by higher throughput volumes in 2007.

Operating and Maintenance Expense — Operating and maintenance expense increased $0.2 million to $0.3 million in 2007 from $0.1 million in 2006, primarily as a result of higher expenses as a result of the addition of our Wilbreeze pipeline in December 2006.

Earnings from Equity Method Investments — Earnings from equity method investments increased to $0.3 million in 2007 from $0.1 million in 2006. This increase was as a result of higher Black Lake transport volumes.

Six Months Ended June 30, 2007 vs. Six Months Ended June 30, 2006

Total Operating Revenues — Total operating revenues increased $1.0 million, or 38%, to $3.6 million in 2007 from $2.6 million in 2006, due to an increase in revenues attributable to an increase in volumes, as well as the composition of inventory transactions at receipt versus delivery points.

Overall, our NGL pipelines experienced an increase in throughput volumes during 2007 as compared to 2006, primarily as a result of the addition of our Wilbreeze pipeline in December 2006.

Purchases of NGLs — Purchases of NGLs increased $0.7 million, or 117%, to $1.3 million in 2007 from $0.6 million 2006, primarily due to an increase in purchases attributable to an increase in volumes, as well as the composition of inventory transactions at receipt versus delivery points.

Segment Gross Margin — Segment gross margin increased $0.3 million, or 15%, to $2.3 million in 2007 from $2.0 million in 2006, primarily due to increased transportation revenue and volumes as a result of the addition of our Wilbreeze pipeline in December 2006, offset by lower per unit margins as a result of changes in product mix at various receipt points.

Operating and Maintenance Expense — Operating and maintenance expense remained relatively constant in 2007 and 2006.

Earnings from Equity Method Investments — Earnings from equity method investments increased to $0.5 million in 2007 from $0.1 million in 2006. This increase was as a result of higher Black Lake transport volumes and reduced operating expenses.

Liquidity and Capital Resources

Sources of liquidity for our wholesale propane logistics business prior to our acquisition of this business from DCP Midstream, LLC included cash generated from operations and funding from DCP Midstream, LLC. Its cash receipts were deposited in DCP Midstream, LLC's bank accounts and all cash disbursements were made from these accounts. Cash transactions handled by DCP Midstream, LLC for our wholesale propane logistics business were reflected in partners' equity as intercompany advances from DCP Midstream, LLC.

We expect our sources of liquidity to include:

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

We anticipate our more significant uses of resources to include:

- capital expenditures
- business acquisitions; and

- quarterly distributions to our unitholders.

We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements, long-term capital expenditure and acquisition requirements, and quarterly cash distributions. Our commodity derivative program, as well as any future derivatives we enter into, may require us to post collateral depending on commodity price movements. DCP Midstream, LLC has issued parental guarantees for a portion of our commodity derivative instruments that span through 2010 for natural gas swaps and crude oil swaps, 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. We have mitigated a significant portion of our anticipated commodity price risk associated with our gathering and processing arrangements through 2013 with natural gas and crude oil swaps. For additional information regarding our derivative activities, please read "— Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk — Hedging Strategies" in our 2006 Form 10-K and "Item 3. Quantitative and Qualitative Disclosures about Market Risk" in this Quarterly Report on Form 10-Q.

Working Capital — Working capital is the amount by which current assets exceed current liabilities. Current assets are reduced by our quarterly distributions, which are required under the terms of our partnership agreement based on Available Cash, as defined in the partnership agreement. In general, our working capital is impacted by changes in the prices of commodities that we buy and sell, along with other business factors that affect our net income and cash flows. Our working capital generally increases in periods of rising commodity prices and declines in periods of falling commodity prices. However, our working capital requirements do not necessarily change at the same rate as commodity prices. Our working capital is also impacted by the timing of operating cash receipts and disbursements, borrowings of and payments on debt, capital expenditures, and increases or decreases in restricted investments and other long-term assets.

We had working capital of $54.9 million and $33.1 million as of June 30, 2007 and December 31, 2006, respectively. The changes in working capital are primarily attributable to the factors described above. We expect that our future working capital requirements will be impacted by these same factors.

Cash Flow — Net cash provided by or used in operating, investing and financing activities for the six months ended June 30, 2007 and 2006 were as follows ($ in millions):

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Net cash provided by operating activities	$ 21.3	$ 26.9
Net cash used in investing activities	$(95.4)	$(13.0)
Net cash provided by (used in) financing activities	$ 82.9	$(35.8)

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, 2007, was primarily used for: (1) asset acquisitions of $191.3 million; and (2) capital expenditures of $7.6 million, which generally consisted of expenditures for construction and expansion of our infrastructure in addition to well connections and other upgrades to our existing facilities; which were partially offset by (3) net sales of available-for-sale securities of $103.4 million. Net cash used in investing activities during the six months ended June 30, 2006 was primarily used for capital expenditures, and net purchases of available-for-sale securities.

Net Cash Provided by (Used in) Financing Activities — Net cash provided by financing activities during the six months ended June 30, 2007, was comprised of borrowings of $188.0 million and the issuance of common units for $128.5 million, net of offering costs, offset by repayment of debt of $207.0 million, the excess of purchase price over the acquired assets attributable to a payment related to our acquisition of our wholesale propane logistics business of $9.9 million, and distributions to our unitholders of $16.4 million. Net cash used in financing activities during the six months ended June 30, 2006 was primarily comprised of repayments of debt, changes in parent advances and distributions to our unitholders.

We expect to continue to use cash in financing activities for the payment of distributions to our unitholders and general partner. See Note 8 of the Notes to Condensed Consolidated Financial Statements in Item 1. "Financial Statements."

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. Our expansion capital expenditures in this segment may include constructing new gathering lines and compression facilities to connect new wells to our Southern Oklahoma system. In our Wholesale Propane Logistics and NGL Logistics segments, our capital expenditures may include the construction of new propane terminals and NGL pipelines that would expand our distribution and transportation capabilities.

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 those 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 $2.7 million and expansion capital expenditures of $7.2 million for the year ending December 31, 2007. During the six months ended June 30, 2007, our capital expenditures totaled $7.6 million, including maintenance capital expenditures of $0.9 million and expansion capital expenditures of $6.7 million. We have an agreement with certain producers whereby these producers will reimburse us for certain capital projects completed by us. During the six months ended June 30, 2007, the changes in receivables and collections of maintenance capital expenditures, from DCP Midstream, LLC and producers, were not significant. During the six months ended June 30, 2006, our capital expenditures totaled $12.1 million, including maintenance capital expenditures of $2.0 million and expansion capital expenditures of $10.1 million.

Maintenance capital expenditures in 2007 were lower than 2006 as a result of a higher number of well connects in the first six months of 2006 versus 2007. Annual expansion capital expenditures in 2007 are expected to increase as a result of the acquisitions detailed above in “Recent Events.” These anticipated increases in capital expenditures in 2007 will be offset by decreases as a result of the completion of Wilbreeze in December 2006, an NGL pipeline, for which expansion capital expenditures were approximately $11.8 million in 2006, and the completion of a substantial portion of our new Midland propane terminal in 2006, for which expansion capital expenditures were approximately $9.2 million in 2006. We expect to fund future capital expenditures with restricted investments, funds generated from our operations, borrowings under our credit facility and the issuance of additional partnership units.

Cash Distributions to Unitholders — Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all cash and cash equivalents on hand at the end of the quarter, less certain reserves as identified in the partnership agreement, to unitholders of record on the applicable record date. We made cash distributions to our unitholders of $16.4 million during the six months ended June 30, 2007, as compared to $8.0 million for the same period in 2006. The distributions paid during 2006 included 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. We intend to make quarterly distribution payments to our unitholders to the extent we have sufficient cash from operations after the establishment of reserves.

Description of Amended Credit Agreement — Through June 20, 2007, we had a 5-year credit agreement, or the Credit Agreement, with a $250.0 million revolving credit facility and a $100.1 million term loan facility, which was to mature on December 7, 2010. As of March 31, 2007, the outstanding balance on the revolving credit facility was $168.0 million and the outstanding balance on the term loan facility was $100.0 million. In conjunction with the April 2007 Northern Louisiana asset acquisition, we used borrowings of $11.0 million from our revolving credit facility to pay down a portion of our term loan facility. As a result of the pay down of our term loan facility, we liquidated $11.0 million of restricted investments, $10.2 million of which were used to fund the Northern Louisiana acquisition. In conjunction with the May 2007 Southern Oklahoma asset acquisition, we used borrowings of $89.0 million from our revolving credit facility to extinguish our term loan facility. As a result of the extinguishment of our term loan facility, we liquidated $90.8 million of restricted investments, which were used to partially fund the Southern Oklahoma asset acquisition. Also in conjunction with the Southern Oklahoma asset acquisition, our earnest deposit of $9.0 million, paid when we entered into the purchase agreement, was returned to us, and was used to retire indebtedness under our revolving credit facility.

On June 21, 2007, we entered into an Amended and Restated Credit Agreement, or the Amended Credit Agreement, which amended our existing Credit Agreement. This new 5-year Amended Credit Agreement consists of a $600.0 million revolving credit facility and a $250.0 million term loan facility, and matures on June 21, 2012. The amendment also improved pricing and certain other terms or conditions of the Credit Agreement. On June 21, 2007, we borrowed $259.0 million from our revolving credit facility under the Amended Credit Agreement to replace existing borrowings under the existing Credit Agreement, of which $10.0 million was repaid in June 2007. As of June 30, 2007, the outstanding balance on the revolving credit facility was $249.0 million.

Our obligations under the revolving credit facility are unsecured, and when we have outstanding debt under the term loan facility, it is secured at all times by high-grade securities, which are classified as restricted investments in the accompanying condensed consolidated balance sheet as of December 31, 2006, in an amount equal to or greater than the outstanding principal amount of the term loan. We did not have outstanding debt under the term loan facility as of June 30, 2007. When outstanding, any portion of the term loan balance may be repaid at any time, and we may then have access to a corresponding amount of the collateral securities. 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. The unused portion of the revolving credit facility may be used for letters of credit. At both June 30, 2007 and December 31, 2006 there were outstanding letters of credit of $0.2 million.

We have the option of increasing the size of the revolving credit facility to $1.0 billion with the consent of the issuing lenders.

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 either: (1) the higher of Wachovia Bank’s prime rate or the federal funds rate plus 0.50%; or (2) LIBOR plus an applicable margin, which ranges from 0.23% to 0.575% dependent upon our leverage level or credit rating. As of June 30, 2007, the weighted-average interest rate on our revolving credit facility was 5.77% per annum. The revolving credit facility incurs an annual facility fee of 0.07% to 0.175% depending on our applicable leverage level or debt rating. This fee is paid on drawn and undrawn portions of the revolving credit facility. The term loan facility bears interest at a rate equal to either: (1) LIBOR plus 0.10%; or (2) the higher of Wachovia Bank’s prime rate or the federal funds rate plus 0.50%.

The Amended Credit Agreement prohibits us from making distributions of Available Cash to unitholders if any default or event of default (as defined in the Amended Credit Agreement) exists. The Amended 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 Amended Credit Agreement) of not more than 5.75 to 1.0 through and including the quarter ended June 30, 2007 and 5.0 to 1.0 thereafter, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of asset acquisitions in the midstream energy business of not more than 5.50 to 1.0. The Amended 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 Amended Credit Agreement) of equal or greater than 2.5 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination.

Bridge Loan

In May 2007, we entered into a two-month bridge loan, or the Bridge Loan, which provided for borrowings up to $100.0 million, and had terms and conditions substantially similar to those of our Credit Agreement. In conjunction with our entering into the Bridge Loan, our Credit Agreement was amended to provide for additional unsecured indebtedness, of an amount not to exceed $100.0 million, which was due and payable no later than August 9, 2007.

We used borrowings on the Bridge Loan of $88.0 million to partially fund the Southern Oklahoma asset acquisition. The remaining $12.0 million available for borrowing on the Bridge Loan was not utilized. We used a portion of the net proceeds of the private placement to extinguish the $88.0 million outstanding on the Bridge Loan.

Total Contractual Cash Obligations and Off-Balance Sheet Arrangements

A summary of our total contractual cash obligations as of June 30, 2007, is as follows ($ in millions):

	Payments Due by Period				
	Total	**Remainder of 2007**	**2008-2009**	**2010-2011**	**2012 and Thereafter**
Long-term debt (a)	$272.6	$ 3.4	$ 13.5	$ 6.7	$ 249.0
Operating lease obligations	41.0	4.8	14.9	10.6	10.7
Purchase obligations (b)	0.2	0.2	—	—	—
Other long-term liabilities (c)	1.2	0.1	—	—	1.1
Total	$315.0	$ 8.5	$ 28.4	$ 17.3	$ 260.8

(a) Includes interest payments on long-term debt that has been hedged, because the interest rate is determinable. Interest payments on long-term debt, which has not been hedged, are not included as they are based on floating interest rates and we cannot determine with accuracy the periodic repayment dates or the amounts of the interest payments.

(b) Purchase obligations exclude accounts payable, accrued interest payable and other current liabilities recognized on the condensed consolidated balance sheet. Purchase obligations also exclude current and long-term unrealized losses on non-trading derivative and hedging instruments included on the condensed consolidated balance sheet, which 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 $1.1 million of asset retirement obligations and $0.1 million of environmental reserves recognized on the June 30, 2007 condensed consolidated balance sheet.

Our off-balance arrangements consist solely of our operating lease obligations.

Recent Accounting Pronouncements

***Statement of Financial Accounting Standards, or SFAS, No. 159, The Fair Value Option for Financial Assets and Financial Liabilities—including an amendment of FAS 115*, or SFAS 159** — In February 2007, the Financial Accounting Standards Board, or FASB, issued SFAS 159, which allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item's fair value in subsequent reporting periods must be recognized in current earnings. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between entities that elect different measurement attributes for similar assets and liabilities. SFAS 159 is effective for us on January 1, 2008. We have not assessed the impact of SFAS 159 on our consolidated results of operations, cash flows or financial position.

***SFAS No. 157, Fair Value Measurements*, or SFAS 157** — In September 2006, the FASB issued SFAS 157, which provides guidance for using fair value to measure assets and liabilities. The standard also responds to investors' requests for more information about: (1) the extent to which companies measure assets and liabilities at fair value; (2) the information used to measure fair value; and (3) the effect that fair value measurements have on earnings. SFAS 157 will apply whenever another standard requires (or permits) assets or liabilities to be measured at fair value. SFAS 157 does not expand the use of fair value to any new circumstances. SFAS 157 is effective for us on January 1, 2008. We have not assessed the impact of SFAS 157 on our consolidated results of operations, cash flows or financial position.

FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes—An Interpretation of FASB Statement 109, or FIN 48 — In July 2006, the FASB issued FIN 48, which clarifies the accounting for uncertainty in income taxes recognized in financial statements in accordance with FASB Statement No. 109, Accounting for Income Taxes. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The provisions of FIN 48 were effective for us on January 1, 2007, and the adoption of FIN 48 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 2006 Form 10-K.

Credit Risk

Our principal customers in the Natural Gas Services segment are large, natural gas marketing servicers and industrial end-users. Our principal customers in the Wholesale Propane Logistics segment are primarily retail propane distributors. In the NGL Logistics segment, our principal customers include an affiliate of DCP Midstream, LLC, producers and marketing companies. Substantially all of our natural gas, propane and NGL sales are made at market-based prices. 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, we analyze the counterparties’ financial condition prior to entering into an agreement, establish credit limits, and monitor the appropriateness of these limits on an ongoing basis. We operate under DCP Midstream, LLC’s corporate credit policy. DCP Midstream, LLC’s corporate credit policy, as well as the standard terms and conditions of our agreements, prescribe the use of financial responsibility and reasonable grounds for adequate assurances. These provisions allow our credit department to request that a counterparty remedy credit limit violations by posting cash or letters of credit for exposure in excess of an established credit line. The credit line represents an open credit limit, determined in accordance with DCP Midstream, LLC’s credit policy. Our standard agreements also provide that the inability of a counterparty to post collateral is sufficient cause to terminate a contract and liquidate all positions. The adequate assurance provisions also allow us to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment to us in a satisfactory form.

Interest Rate Risk

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.

We mitigate a portion of our interest rate risk with interest rate swaps, which reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. During 2006, we entered into interest rate swap agreements to mitigate the variable interest rate on $125.0 million of the indebtedness outstanding under our revolving credit facility. On August 1, 2007, we entered into interest rate swap agreements, which commence on September 21, 2007, expire on June 21, 2012 and re-price prospectively approximately every 90 days, to mitigate the variable interest rate on $200.0 million of the indebtedness outstanding under our revolving credit facility. 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.

Based on the annualized unhedged borrowings under our revolving credit facility of $170.0 million, a 0.5% movement in the base rate or LIBOR rate would result in an approximately $0.9 million annualized increase or decrease in interest expense.

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. For gathering services, we receive fees or commodities from producers to bring the raw natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, depending on the types of contracts. 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.

As of June 30, 2007, we have mitigated a significant portion of our expected natural gas, NGL and condensate commodity price risk through 2013 with natural gas and crude oil non-trading derivatives. In addition to our previously existing non-trading derivative positions, in the second quarter of 2007 we entered into the following non-trading derivative positions.

In May 2007, we executed a series of financial derivatives to mitigate a portion of the commodity price exposure associated with the Southern Oklahoma asset acquisition. We entered into natural gas swap contracts for 1,500 MMBtu/d at $7.54 per MMBtu and crude oil swap contracts for 650 Bls/d at $67.60 per Bbl for a term from June 2007 through December 2013.

In June 2007, we executed a series of financial derivatives to mitigate a portion of the commodity price exposure associated with our Northern Louisiana system assets. We entered into crude oil swap contracts for 250 Bbls/d at $71.35/Bbl for 2011, 600 Bbls/d at $71.00/Bbl for 2012 and 600 Bbls/d at $71.20/Bbl for 2013.

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. We will use the mark-to-market method of accounting for all commodity cash flow hedges, which is expected to significantly increase the volatility of our results of operations as we will recognize, in current earnings, all non-cash gains and losses from the mark-to-market on non-trading derivative activity. We estimate the following non-cash sensitivities related to the mark-to-market on our commodity derivatives:

	Per Unit Increase	Unit of Measurement	Estimated Mark-to-Market Impact (Decrease in Net Income)
Natural gas prices	$ 1.00	MMBtu	$ 7.4
Crude oil prices	$ 5.00	Barrel	$ 20.5

These sensitivities include the effect of all non-cash gains and losses from the mark-to-market on non-trading derivative activities. The calculation includes the estimated impact of the contribution of a financial derivative to mitigate a portion of the commodity price exposure associated with the acquisition of a 25% limited liability company interest in DCP East Texas Holdings, LLC, and a 40% limited liability company interest in Discovery Producer Services LLC on July 1, 2007. This contract consists of crude oil swaps at $66.72/Bbl for 1,100 Bls/day through 2007, 1,000 Bbls/d through 2008, 925 Bbls/d through 2009, 900 Bbls/d through 2010, 875 Bbls/d through 2011 and 850 Bbls/d through 2012.

We estimate the following annualized sensitivities, excluding any impact from the mark-to-market on our commodity derivatives, due to the impact of market fluctuations:

	Per Unit Decrease	Unit of Measurement	Estimated Decrease in Annual Net Income
Natural gas prices	$ 1.00	MMBtu	$ 0.8
NGL prices	$ 0.10	Gallon	$ 0.9
Crude oil prices	$ 5.00	Barrel	$ 0.1

Based on our current contract mix, we believe that during the remainder of 2007 we will have a long position in natural gas, NGLs and condensate, and will be sensitive to changes in commodity prices.

These sensitivities include the effect of settlements on our financial derivatives. The calculation includes the estimated impact of the acquisition of a 25% limited liability company interest in DCP East Texas Holdings, LLC, a 40% limited liability company interest in Discovery Producer Services LLC and a derivative instrument on July 1, 2007. Please read "— Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk — Hedging Strategies" in our 2006 Form 10-K for more information about these hedging strategies and our commodity price risk.

While the above commodity price sensitivities are indicative of the impact that changes in commodity prices may have on our annualized net income, changes during certain periods of extreme price volatility and market conditions or changes in the correlation of the price of NGLs and crude oil our commodity price sensitivities may vary significantly from these estimates.

The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by the prevailing price of NGLs, which in turn has been generally correlated to the price of crude oil. Although the prevailing price of natural gas has less short term significance to our operating results than the price of NGLs, in the long term the growth and sustainability of our business depends on natural gas prices being at levels sufficient to provide incentives and capital, for producers to increase natural gas exploration and production. In the past, the prices of NGLs, crude oil and natural gas have been extremely volatile.

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, 2007 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 11, “Commitments and Contingent Liabilities,” included in the Notes to Condensed Consolidated Financial Statements included under Part I. “Item 1. Financial Statements,” which information is incorporated by reference into this item.

Item 1A. *Risk Factors*

In addition to the other information set forth in this report, careful consideration should be given to the risk factors discussed in Part I, “Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2006, or our 2006 Form 10-K. An investment in our securities involves various risks. When considering an investment in us, you should consider carefully all of the risk factors described in our 2006 Form 10-K. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may also materially adversely affect our consolidated results of operations, financial condition and cash flows.

The following is a new or modified risk factor that should be read in conjunction with the risk factors disclosed in our 2006 Form 10-K:

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders’ sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders’ tax returns without the benefit of additional deductions.

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

In March 2007, we purchased 4,000 common units on the open market to be used for director compensation pursuant to the DCP Midstream Partners, LP Long-Term Incentive Plan. Such units were held as treasury units at June 30, 2007.

On May 21, 2007, in connection with the Momentum Energy Group Inc., or MEG, acquisition, we entered into a common unit purchase agreement with certain institutional investors to sell 2,380,952 common limited partner units in a private placement at $42.00 per unit, or approximately $100.0 million in the aggregate. In connection with this common unit purchase agreement, we have a registration obligation that is contingent upon closing of the MEG acquisition.

On June 22, 2007, we entered into a private placement agreement with a group of institutional investors for $130.0 million, representing 3,005,780 common limited partner units at a price of $43.25 per unit, and received proceeds of $128.5 million, net of offering costs. In connection with this private placement agreement, we entered into a registration rights agreement with institutional investors that requires us to file a shelf registration statement with the Securities and Exchange Commission to register the units by the earlier of within 120 days of the close of the private placement or when a shelf registration statement is filed to register the units to be issued in connection with the MEG acquisition. In addition the registration rights agreement requires us to use our commercially reasonable efforts to cause the registration statement to become effective within 210 days of the closing of the private placement, or we will be liable to the institutional investors for liquidated damages of 0.25% of the product of the purchase price times the number of registrable securities held by the institutional investors per 30-day period for the first 60 days following the 210th day, increasing by an additional 0.25% of the product of the purchase price times the number of registrable securities held by the institutional investors per 30-day period for each subsequent 60 days, up to a maximum of 1.00% of the product of the purchase price times the number of registrable securities held by the institutional investors per 30-day period.

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Item 6. ***Exhibits***

Exhibits

Exhibit Number	Description
10.1	Fifth Amendment to Omnibus Agreement dated August 7, 2007, among DCP Midstream, LLC, DCP Midstream Partners, LP, DCP Midstream GP, LP, DCP Midstream GP, LLC, 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 9, 2007.

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 Officer)

EXHIBIT INDEX

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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.

FIFTH AMENDMENT
TO
OMNIBUS AGREEMENT

This Fifth Amendment to Omnibus Agreement (this "Amendment") is dated as of August 7, 2007 and entered into by and among DCP Midstream, LLC, a Delaware limited liability Company ("DCPM"), DCP Midstream GP, LLC, a Delaware limited liability company ("DCPM GP LLC"), DCP Midstream GP, LP, a Delaware limited partnership (the "General Partner"), DCP Midstream Partners, LP, a Delaware limited partnership (the "MLP"), and DCP Midstream Operating, LP (the "OLP"). The above-named entities are sometimes referred to in this Amendment each as a "Party" and collectively as the "Parties".

RECITALS

A. The Parties entered into that certain Omnibus Agreement dated as of December 7, 2005, as amended by that certain First Amendment to Omnibus Agreement dated April 1, 2006, Second Amendment to Omnibus Agreement dated November 1, 2006, Third Amendment to Omnibus Agreement dated May 9, 2007 and Fourth Amendment to Omnibus Agreement dated July 1, 2007 (together referred to as the "Omnibus Agreement") (capitalized terms used but not defined herein shall have the meaning given thereto in the Omnibus Agreement).

B. Section 3.3 of the Omnibus Agreement currently addresses the fixed general and administrative expenses for the original assets that were part of the MLP's initial public offering, the Gas Supply Resources LLC assets ("GSR") transferred to the MLP in the transaction set forth in that certain Contribution Agreement between DCP LP Holdings, LP and the MLP, dated as of October 9, 2006 (the "GSR Contribution Agreement"), the assets acquired by the MLP from Anadarko Anadarko Gathering Company and Anadarko Energy Services Company in the transaction set forth in that certain Purchase and Sale Agreement dated March 7, 2007 (the "Panther PSA"), and the 40% interest in Discovery Producer Services, LLC (the general and administrative expenses for the MLP's 25% interest in DCP East Texas Holdings, LLC is addressed in the limited liability company agreement for that entity) transferred to the MLP in the transaction set forth in that certain Contribution Agreement between DCP LP Holdings, LP and the MLP dated May 23, 2007 (the "Columbus Contribution Agreement").

C. The Parties desire to amend Section 2.3(a)(iv) of the Omnibus Agreement to delete references to Discovery Producer Services, LLC in that section, amend Section 3.3 of the Omnibus Agreement to adjust the fixed general and administrative expenses to take into account additional resources used by the MLP on a full time basis, and amend Section 3.3 of the Omnibus Agreement to extend the term for an additional year so that the expiration will be December 31, 2009.

FOR GOOD AND VALUABLE CONSIDERATION, the receipt and sufficiency of which is hereby acknowledge, the Parties hereby agree as follows:

1. **Omnibus Agreement Amendment to Section 2.3(a)(iv).** The Omnibus Agreement is hereby amended by replacing Section 2.3(a)(iv) in its entirety with the following:

(iv) the assets, liabilities, business or operations of any of (a) PanEnergy Dauphin Island LLC, a Delaware limited liability company ("*PanEnergy*"), (b) Gulf Coast NGL Pipeline, LLC, a Delaware limited liability company ("*Gulf Coast*"), (c) Centana Gathering LLC, a Delaware limited liability company ("*Centana*"), (d) DEFS Industrial Gas Co., LLC, a Delaware limited liability company ("*DIGC*"), and (e) Centana Intrastate Pipeline LLC, a Delaware limited liability company ("*CIP*"); and

2. **Omnibus Agreement Amendment to Section 3.3(a)**. The Omnibus Agreement is hereby amended by replacing Section 3.3(a) in its entirety with the following:

The amount for which DCPM shall be entitled to reimbursement from the Partnership Group pursuant to Section 3.1(b) for general and administrative expenses (excluding direct bill items associated with public company costs and insurance) associated with:

(ii) the original assets that were part of the MLP's initial public offering shall be a fixed fee equal to $4.8 million per year through calendar year 2006 (the "IPO G&A Expenses Limit"). After calendar year 2006, the IPO G&A Expenses Limit shall be increased annually by the percentage increase in the Consumer Price Index – All Urban Consumers, U.S. City Average, Not Seasonally Adjusted for the applicable year (the "CPI Adjustment").

(iii) the contribution of the GSR assets to the MLP in the GSR Contribution Agreement shall be a fixed fee equal to $2.0 million per year for calendar years 2006 and 2007 (the "GSR G&A Expenses Limit"), but shall be prorated for calendar year 2006 based on the number of days remaining in calendar year 2006 following the Closing Date (as that term is defined in the GSR Contribution Agreement). After calendar year 2007, the GSR G&A Expenses Limit shall be increased by the CPI Adjustment.

(iv) the operation of the Antioch Gathering System (acquired under the Panther PSA) shall be a fixed fee equal to $200,000 per year for calendar year 2007 (the "Panther G&A Expenses Limit"), but shall be prorated for calendar year 2007 based on the number of days remaining in calendar year 2007 following the Closing Date (as that term is defined in the Panther PSA). After calendar year 2007, the Panther G&A Expenses Limit shall be increased by the CPI Adjustment.

(v) the contribution to the MLP of the interest in Discovery Producer Services, LLC under the Columbus Contribution Agreement shall be a fixed fee equal to $158,000 per year for calendar year 2007 (the "Discovery G&A Expenses

Limit”), but shall be prorated for calendar year 2007 based on the number of days remaining in calendar year 2007 following the Closing Date (as that term is defined in the Columbus Contribution Agreement). After calendar year 2007, the Discovery G&A Expenses Limit shall be increased by the CPI Adjustment.

(vi) the 2007 Adjustment to add three additional full time equivalents that devote 100% of their time to the MLP shall be a fixed fee equal to $561,584 per year for calendar year 2007 (the “2007 Adjustment Expenses Limit”), but shall be prorated for calendar year 2007 based on the number of days remaining in calendar year 2007 following August 1, 2007. After calendar year 2007, the 2007 Adjustment Expense Limit shall be increased by the CPI Adjustment.

(vii) For time periods after December 31, 2009, DCPM and the General Partner will determine the amount of general and administrative expenses contemplated by this paragraph that will be properly allocated to the Partnership in accordance with the terms of the Partnership Agreement.

(viii) If the Partnership Group makes any additional acquisitions of assets or businesses or the business of the Partnership Group otherwise expands following the date of this Agreement, then the IPO G&A Expenses Limit shall be appropriately increased in order to account for adjustments in the nature and extent of the general and administrative services by DCPM to the Partnership Group, with any such increase subject to the approval of both the Special Committee of DCPM GP LLC’s Board of Directors and DCPM.

3. **Acknowledgement**. Except as amended hereby, the Omnibus Agreement shall remain in full force and effect as previously executed, and the Parties hereby ratify the Omnibus Agreement as amended hereby.

4. **Counterparts**. This Amendment may be executed in one or more counterparts, all of which shall be considered one and the same agreement, and shall become effective when one or more counterparts have been signed by each of the Parties hereto and delivered (including by facsimile) to the other Parties.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

EACH OF THE UNDERSIGNED, intending to be legally bound, has caused this Amendment to be duly executed and delivered to be effective as of August 7, 2007, regardless of the actual date of execution of this Amendment.

DCP MIDSTREAM, LLC

By: /s/ Brent L. Backes
Name: Brent L. Backes
Title: Group Vice President, General Counsel & Secretary

DCP MIDSTREAM GP, LLC

By: /s/ Greg K. Smith
Name: Greg K. Smith
Title: Vice President

DCP MIDSTREAM GP, LP
By: DCP MIDSTREAM GP, LLC, its general partner

By: /s/ Greg K. Smith
Name: Greg K. Smith
Title: Vice President

DCP MIDSTREAM PARTNERS, LP
By: DCP MIDSTREAM GP, LP, its general partner
By: DCP MIDSTREAM GP, LLC, its general partner

By: /s/ Greg K. Smith
Name: Greg K. Smith
Title: Vice President

DCP MIDSTREAM OPERATING, LP

By: /s/ Greg K. Smith
Name: Greg K. Smith
Title: Vice President

Exhibit 31.1

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Mark A. Borer, certify that:

1. I have reviewed this quarterly report on Form 10-Q of DCP Midstream Partners, LP for the three and six months ended June 30, 2007;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financials statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 9, 2007

/s/ Mark A. Borer

Mark A. Borer
Chief Executive Officer

Exhibit 31.2

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Thomas E. Long, certify that:

1. I have reviewed this quarterly report on Form 10-Q of DCP Midstream Partners, LP for the three and six months ended June 30, 2007;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financials statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 9, 2007

/s/ Thomas E. Long

Thomas E. Long
Chief Financial Officer

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 (18 U.S.C. Section 1350)

The undersigned, the Chief Executive Officer of DCP Midstream GP, LLC, a Delaware limited liability company and general partner of DCP Midstream GP, LP, general partner of DCP Midstream Partners, LP (the “Partnership”), hereby certifies that, to his knowledge on the date hereof:

(a) the quarterly report on Form 10-Q of the Partnership for the three and six months ended June 30, 2007, filed on the date hereof with the Securities and Exchange Commission (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(b) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ Mark A. Borer

Mark A. Borer
Chief Executive Officer
August 9, 2007

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 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 (18 U.S.C. Section 1350)

The undersigned, the Chief Financial Officer of DCP Midstream GP, LLC, a Delaware limited liability company and general partner of DCP Midstream GP, LP, general partner of DCP Midstream Partners, LP (the “Partnership”), hereby certifies that, to his knowledge on the date hereof:

(a) the quarterly report on Form 10-Q of the Partnership for the three and six months ended June 30, 2007, filed on the date hereof with the Securities and Exchange Commission (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(b) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ Thomas E. Long
Thomas E. Long
Chief Financial Officer
August 9, 2007

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.