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

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): January 15, 2008

DCP MIDSTREAM PARTNERS, LP

(Exact name of registrant as specified in its charter)

Delaware	**001-32678**	**03-0567133**
(State or other jurisdiction of incorporation)	**(Commission File Number)**	**(IRS Employer Identification No.)**

370 17th Street, Suite 2775 **Denver, Colorado**	**80202**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (303) 633-2900

(Former name or former address, if changed since last report.)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01. Other Events.

On July 1, 2007, DCP Midstream Partners, LP, or the Partnership, closed its previously announced acquisition of a 25% limited liability company interest in DCP East Texas Holdings, LLC (“East Texas”), a 40% limited liability company interest in Discovery Producer Services LLC (“Discovery”) and a non-trading derivative instrument (the “Swap”) from DCP Midstream, LLC. The transfer of assets between DCP Midstream, LLC and the Partnership 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. On October 17, 2007, the Partnership filed a Current Report on Form 8-K which included supplemental consolidated financial statements of the Partnership as of December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, accounting for the acquisition similar to the pooling method. The Current Report on Form 8-K also included unaudited supplemental consolidated financial statements as of June 30, 2007 and for the six months ended June 30, 2007 and 2006.

Included herein as Exhibit 99.3 are the audited consolidated financial statements and financial statement schedule of the Partnership as of December 31, 2006 and 2005 and for each of the three years in the period ended December 31, 2006, as well as the unaudited consolidated financial statements of the Partnership as of June 30, 2007 and for the six months ended June 30, 2007 and 2006. These audited consolidated financial statements and financial statement schedule and unaudited consolidated financial statements give retroactive effect to the acquisition of East Texas, Discovery and the Swap. These audited consolidated financial statements become the Partnership’s historical consolidated financial statements since financial statements covering the date of consummation of the acquisition were filed on November 9, 2007 on Form 10-Q. These audited consolidated financial statements and financial statement schedule replace Items 8 and 15 in the Partnership’s 2006 Form 10-K filed on March 14, 2007. Also, included herein as Exhibit 99.1 is the Selected Financial Data, for which years 2006, 2005 and 2004 are derived from the audited consolidated financial statements, while the remaining periods are derived from the unaudited consolidated financial statements, and replaces Item 6 in the Partnership’s 2006 Form 10-K filed on March 14, 2007. Included herein as Exhibit 99.2 is Management’s Discussion and Analysis of Financial Condition and Results of Operations, which relates to the consolidated financial statements and unaudited consolidated financial statements, and replaces Item 7 in the Partnership’s 2006 Form 10-K filed on March 14, 2007.

Item 9.01. Financial Statements and Exhibits.

(a) Not applicable.

(b) Not applicable.

(c) Not applicable.

(d) Exhibits.

Exhibit Number	Description
Exhibit 23.1	Consent of Deloitte & Touche LLP on Consolidated Financial Statements of DCP Midstream Partners, LP.
Exhibit 23.2	Consent of Ernst & Young LLP on Consolidated Financial Statements of Discovery Producer Services LLC.
Exhibit 99.1	Selected Financial Data.
Exhibit 99.2	Management’s Discussion and Analysis of Financial Condition and Results of Operations.
Exhibit 99.3	Consolidated Financial Statements of DCP Midstream Partners, LP.

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 hereunto duly authorized.

DCP Midstream Partners, LP

By: DCP Midstream GP, LP
its General Partner

By: DCP Midstream GP, LLC
its General Partner

Date: January 15, 2008

/s/ Thomas E. Long

Name: Thomas E. Long
Title: Vice President and Chief Financial Officer

EXHIBIT INDEX

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Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-142271 on Form S-8 and in Amendment No. 1 to Registration Statement No. 333-142278 on Form S-3 of our report dated October 16, 2007, relating to the consolidated financial statements and financial statement schedule of DCP Midstream Partners, LP (which report expresses an unqualified opinion and includes explanatory paragraphs referring to (1) the preparation of the portion of the DCP Midstream Partners, LP consolidated financial statements attributable to operations prior to December 7, 2005 from the separate records of DCP Midstream, LLC, and (2) the basis of presentation of the consolidated financial statements of DCP Midstream Partners, LP to retroactively reflect DCP Midstream Partners, LP's acquisition of the wholesale propane logistics business and the preparation of the portion of the DCP Midstream Partners, LP consolidated financial statements attributable to the wholesale propane logistics business from the separate records maintained by DCP Midstream, LLC and (3) the preparation of the portion of the DCP Midstream Partners, LP consolidated financial statements attributable to the East Texas Midstream Business, Discovery Producer Services, LLC, and a nontrading derivative instrument from the separate records maintained by DCP Midstream, LLC), appearing in this Current Report on Form 8-K dated January 15, 2008.

/s/ Deloitte & Touche LLP

Denver, Colorado
January 15, 2008

Exhibit 23.2

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statements on Form S-8 (No. 333-142271) and Form S-3 (No. 333-142278) of DCP Midstream Partners, LP of our report dated March 5, 2007, with respect to the consolidated financial statements of Discovery Producer Services LLC, included in the Current Report (Form 8-K) dated January 15, 2008, filed with the Securities and Exchange Commission.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
January 11, 2008

Exhibit 99.1

Selected Financial Data

The following table shows our selected financial data for the periods and as of the dates indicated, and includes the effect of the acquisition of a 25% limited liability company interest in DCP East Texas Holdings, LLC, or East Texas, a 40% limited liability company interest in Discovery Producer Services LLC, or Discovery, and a non-trading derivative instrument, or the Swap, which DCP Midstream, LLC entered into in March 2007, for periods after January 1, 2002. This acquisition was accounted for in a manner similar to a pooling of interests. The information contained herein should be read in conjunction with, and is qualified in its entirety by reference to, our "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Consolidated Financial Statements" contained in this Form 8-K.

The selected financial data as of June 30, 2007 and for the six months ended June 30, 2007 and 2006 is derived from our unaudited consolidated financial statements. For the six month periods ended June 30, 2007 and 2006, all adjustments, consisting only of normal recurring adjustments, which are in our opinion necessary for a fair presentation of interim consolidated financial statements, have been included. Results for the six months ended June 30, 2007 and 2006 are not necessarily indicative of the results for the full year.

The selected financial data as of December 31, 2006, 2005 and 2004, as well as the selected financial data for the years ended December 31, 2006, 2005 and 2004, are derived from the audited consolidated financial statements. The selected financial data as of December 31, 2003 and 2002, as well as the selected financial data for the years ended December 31, 2003 and 2002 are derived from the consolidated financial statements. Collectively, these consolidated financial statements include our accounts, and prior to December 7, 2005, the assets, liabilities and operations contributed to us by DCP Midstream, LLC and its wholly-owned subsidiaries, or DCP Midstream Partners Predecessor, upon the closing of the initial public offering, which have been combined with the historical assets, liabilities and operations of our wholesale propane logistics business, the historical equity method investments and equity earnings of Discovery and East Texas, and the Swap, which we acquired from DCP Midstream, LLC in November 2006 and July 2007, respectively. These were transactions among entities under common control; accordingly, our financial information includes the historical results of our wholesale propane logistics business, Discovery and East Texas for all periods presented.

Our operating results incorporate a number of significant estimates and uncertainties. Such matters could cause the data included herein to not be indicative of our future financial conditions or results of operations. A discussion on our critical accounting estimates is included in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Six Months Ended June 30,		Year Ended December 31,				
	2007	2006	2006	2005	2004	2003	2002
	(unaudited)		($ in millions, except per unit data)				
Statements of Operations Data:							
Total operating revenues (a)	$418.3	$425.5	$795.8	$1,144.3	$834.0	$765.7	$553.3
Operating costs and expenses:							
Purchases of natural gas, propane and NGLs	376.1	379.9	700.4	1,047.3	760.6	706.1	499.3
Operating and maintenance expense	12.9	11.5	23.7	22.4	19.8	18.3	17.2
Depreciation and amortization expense	7.9	6.4	12.8	12.7	14.7	15.5	14.9
General and administrative expense	11.7	9.3	21.0	14.2	8.7	9.5	7.4
Net gain on sale of assets	—	—	—	—	—	—	(0.1)
Total operating costs and expenses	408.6	407.1	757.9	1,096.6	803.8	749.4	538.7
Operating income	9.7	18.4	37.9	47.7	30.2	16.3	14.6
Interest income	2.5	3.0	6.3	0.5	—	—	—
Interest expense	(8.4)	(5.2)	(11.5)	(0.8)	—	—	—
Earnings from equity method investments (b)	12.8	15.8	29.2	25.7	17.6	11.2	(0.2)
Impairment of equity method investment (c)	—	—	—	—	(4.4)	—	—
Income tax expense (d)	—	—	—	(3.3)	(2.5)	(3.6)	(1.1)
Net income	$ 16.6	$ 32.0	$ 61.9	$ 69.8	$ 40.9	$ 23.9	$ 13.3
Less:							
Net income attributable to predecessor operations (e)	(3.6)	(17.8)	(26.6)	(65.1)	(40.9)	(23.9)	(13.3)
General partner interest in net income	(0.6)	(0.3)	(0.7)	(0.1)	—	—	—
Net income allocable to limited partners	$ 12.4	$ 13.9	$ 34.6	$ 4.6	$ —	$ —	$ —
Net income per limited partner unit — basic and diluted	$ 0.60	$ 0.79	$ 1.90	$ 0.20	$ —	$ —	$ —

	June 30, 2007 (unaudited)	December 31, 2006	2005	2004	2003	2002
				($ in millions)		
Balance Sheet Data (at period end):						
Property, plant and equipment, net	$ 370.7	$194.7	$178.7	$179.3	$189.6	$201.8
Total assets	$ 749.0	$665.9	$680.1	$472.5	$467.4	$384.3
Accounts payable	$ 92.3	$117.3	$138.3	$ 63.5	$ 62.3	$ 60.7
Long-term debt	$ 249.0	$268.0	$210.1	$ —	$ —	$ 0.1
Partners' equity	$ 374.3	$267.7	$320.7	$400.5	$395.1	$314.6

	Six Months Ended June 30, 2007	2006	Year Ended December 31, 2006	2005	2004	2003	2002
	(unaudited)						
Other Information:							
Cash distributions declared per unit	$0.995	$0.730	$1.565	$0.095	N/A	N/A	N/A
Cash distributions paid per unit	$0.895	$0.445	$1.230	N/A	N/A	N/A	N/A

(a) Includes the effect of the acquisition of the Swap entered into by DCP Midstream, LLC in March 2007. The Swap is for a total of approximately 1.9 million barrels at $66.72 per barrel, and reduced revenues by $8.7 million (unaudited) for the six months ended June 30, 2007.

(b) Includes the effect of the acquisition of a 25% limited liability company interest in East Texas and a 40% limited liability company interest in Discovery, as well as the amortization of the net difference between the carrying amount of Discovery and the underlying equity of Discovery.

(c) In 2004, we recorded an impairment of our 50% interest in Black Lake totaling $4.4 million as an impairment of equity method investment.

(d) Income tax expense for 2002 through 2005 is applicable to the results of operations of our wholesale propane logistics business. We incurred no income tax expense in 2006, due to the change in tax status of our wholesale propane logistics business in December 2005. See Note 15 of the Notes to Consolidated Financial Statements in "Consolidated Financial Statements."

(e) Includes the net income attributable to DCP Midstream Partners Predecessor through December 7, 2005, the net income (loss) attributable to our wholesale propane logistics business prior to the date of our acquisition from DCP Midstream, LLC in November 2006, and the net income attributable to the acquisition of a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery, and the Swap for all periods presented.

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 consolidated financial statements and notes included elsewhere in this 8-K. We refer to the assets, liabilities and operations contributed to us by DCP Midstream, LLC and its wholly-owned subsidiaries upon the closing of our initial public offering as DCP Midstream Partners Predecessor, which have been combined with the historical assets, liabilities and operations of our wholesale propane logistics business, which we acquired from DCP Midstream, LLC in November 2006, and of our 25% limited liability company interest in DCP East Texas Holdings, LLC, or East Texas, our 40% limited liability company interest in Discovery Producer Services LLC, or Discovery, and a non-trading derivative instrument, or the Swap, which DCP Midstream, LLC entered into in March 2007, which we acquired from DCP Midstream, LLC in July 2007. We refer to DCP Midstream Partners Predecessor, our wholesale propane logistics business, East Texas and Discovery collectively as our "predecessors."

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, and includes the effect of the acquisition of a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery, and the Swap;
- 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 our accounts, and prior to December 7, 2005, the assets, liabilities and operations of DCP Midstream Partners Predecessor. In November 2006 we acquired our wholesale propane logistics business from DCP Midstream, LLC, and in July 2007 we acquired a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery, and the Swap, in transactions among entities under common control. Accordingly, our financial information includes the historical results of our wholesale propane logistics business and of East Texas, Discovery and the Swap for all periods presented. The historical financial statements of DCP Midstream Partners Predecessor included in this 8-K and discussed elsewhere herein include DCP Midstream Partners Predecessor's 50% ownership interest in Black Lake Pipe Line Company, or Black Lake. However, effective December 7, 2005, DCP Midstream, LLC retained a 5% interest and we own a 45% interest in Black Lake.

Recent Events

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

In November 2007 we were required to have posted collateral with certain counterparties to our commodity derivative instruments of approximately $9.0 million.

In October 2007, we filed with the SEC a registration statement on Form S-3, which will, upon effectiveness, allow us to register the 3,005,780 common limited partner units represented in the June private placement agreement and the 2,380,952 common limited partner units represented in the August private placement agreement.

On October 24, 2007, the board of directors of the General Partner declared a quarterly distribution of $0.55 per unit, payable on November 14, 2007 to unitholders of record on November 7, 2007. This distribution of $0.55 per unit exceeds the Fourth Target Distribution level. 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 of the Notes to Consolidated Financial Statements in "Consolidated Financial Statements" for discussion of distributions of available cash).

In September 2007, we received a distribution of $5.0 million from East Texas, for the third quarter of 2007. In October 2007, we received a distribution of $5.6 million from Discovery for the third quarter of 2007, and in July 2007, we received a distribution of $3.6 million from Discovery for the second quarter of 2007.

In conjunction with DCP Midstream, LLC's acquisition of Momentum Energy Group, Inc., or MEG, in August 2007, we acquired certain subsidiaries of MEG from DCP Midstream, LLC for aggregate consideration of approximately $165.8 million, subject to final closing adjustments. The consideration consisted of approximately $153.8 million of cash and the issuance of 275,735 common units to an affiliate of DCP Midstream, LLC that were valued at approximately $12.0 million. We have incurred post-closing purchase price adjustments to date that include a liability of $9.0 million for net working capital and general and administrative charges. The subsidiaries of MEG own gathering, processing and compression assets in the Piceance and Powder River producing basins. The Piceance Basin assets consist of a 70 percent operating interest in the 31-mile Collbran Valley Gas Gathering system joint venture, which gathers and processes natural gas from over 20,000 dedicated acres in western Colorado. The processing facility capacity is currently being expanded from 60 MMcf/d to 120 MMcf/d. The other partners in the joint venture, Plains Exploration and Delta Petroleum, are also the producers on the system. The Powder River Basin assets include the 1,324-mile Douglas gas gathering system, which gathers approximately 30 MMcf/d of gas and covers more than 4,000 square miles in Wyoming. Also included in the transaction are the idle Painter Unit fractionator and Millis terminal, and associated NGL pipelines in southwest Wyoming. DCP Midstream, LLC will manage and operate these assets on our behalf. We financed this transaction with borrowings under our amended credit facility of $120.0 million, the issuance of common units through a private placement with certain institutional investors and cash on hand. In August 2007, we sold 2,380,952 common units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100 million in the aggregate. In connection with this common unit purchase agreement, we have a registration rights agreement that requires us to register the units within 90 days of the close of the private placement, and have filed a registration statement with the SEC. In addition, the registration rights agreement requires us to use our commercially reasonable efforts to cause the registration statement to become effective within 180 days of the closing of the private placement. If the registration statement covering the common units is not declared effective by the SEC within 180 days of the closing of the private placement, then we will be liable to the purchasers for liquidated damages of 0.25% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period for the first 60 days following the 180th day, increasing by an additional 0.25% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period for each subsequent 60 days, up to a maximum of 1.00% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period.

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. The Omnibus Agreement was further amended in August 2007 to include an additional annual fee of $1.6 million in connection with our acquisition of the MEG subsidiaries, described above.

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. These interest rate swaps commenced 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 1, 2007, we acquired a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery and the Swap from DCP Midstream, LLC for aggregate consideration of approximately $271.3 million, consisting of approximately $243.7 million in cash, including $1.3 million for net working capital and other adjustments, the issuance of 620,404 common units to DCP Midstream, LLC 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 of $245.9 million under our credit facility, which was amended on June 22, 2007 as described below. We are providing this “Management’s Discussion and Analysis of Financial Condition and Results of Operations” to include the effect of this acquisition.

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.

In June 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 register the units by the earlier of within 120 days of the close of the private placement or when a registration statement is filed to register the units to be issued and sold by us in connection with the MEG acquisition, and we have met the requirement to file a registration statement with the SEC. 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 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. 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 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 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 June 2007.

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." 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.

General Trends and Outlook

We expect our business to continue to be affected by the following key trends. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

Natural Gas Supply and Outlook — We believe that current natural gas prices will continue to cause relatively strong levels of natural gas-related drilling in the United States as producers seek to increase their level of natural gas production. Although the number of natural gas wells drilled in the United States has increased overall in recent years, a corresponding increase in production has not been realized, primarily as a result of smaller discoveries and the decline in production from existing wells. We believe that an increase in United States drilling activity, additional sources of supply such as liquified natural gas, and imports of natural gas will be required for the natural gas industry to meet the expected increased demand for, and to compensate for the slowing production of, natural gas in the United States. A number of the areas in which we operate are experiencing significant drilling activity, new increased drilling for deeper natural gas formations, and the implementation of new exploration and production techniques.

While we anticipate continued high levels of exploration and production activities in a number of the areas in which we operate, fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new natural gas reserves. Drilling activity generally decreases as natural gas prices decrease. We have no control over the level of drilling activity in the areas of our operations.

Wholesale Propane Supply and Outlook — We are a wholesale supplier of propane for the Midwest and northeastern United States, which consists of New York, Pennsylvania, Ohio, Massachusetts, Vermont, New Hampshire, Rhode Island, Connecticut and Maine. Pipeline deliveries to this region in the winter season are generally at capacity and competing propane supply sources, generally consisting of open access propane terminals supplied by interstate pipelines, can have significant supply constraints or outages during peak market conditions. Due to our multiple propane supply sources, propane supply contractual 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.

We manage our wholesale propane margins by selling propane to retail propane distributors under annual sales agreements negotiated each spring. These agreements 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 derivate 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.

Processing Margins — Our processing profitability is dependent upon pricing and market demand for natural gas, NGLs and condensate, which are beyond our control and have been volatile. We have mitigated our exposure to commodity price movements for these commodities by entering into derivative arrangements through 2013 for a significant portion of our currently anticipated natural gas and NGL price risk associated with our percentage-of-proceeds arrangements, and our operations associated with condensate recovered from our gathering operations. For additional information regarding our hedging activities, please read "— Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk — Hedging Strategies."

Falling Commodity Prices — During the aftermath of hurricanes Katrina and Rita, which negatively affected the nation's short term energy supply in the latter part of 2005, natural gas, NGL and condensate prices experienced a significant increase. Prices for these commodities have since decreased.

Impact of Inflation — Our industry has experienced rising inflation due to increased activity in the energy sector. Consequently, our costs for chemicals, utilities, materials and supplies, contract labor and major equipment purchases have increased. In the future, we may continue to be affected by inflation. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher fees.

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 below in "Critical Accounting Policies and Estimates — Revenue Recognition."

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" and "Quantitative and Qualitative Disclosures about Market Risk."

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.

Our operations within the Natural Gas Services segment include a 25% limited liability company interest in East Texas and a 40% limited liability company interest in Discovery. East Texas is engaged in the business of gathering, transporting, treating, compressing, processing, and fractionating natural gas and NGLs. Their operations, located near Carthage, Texas, include a natural gas processing complex with a total capacity of 780 million cubic feet per day. The facility is connected to their 845 mile gathering system, as well as third party gathering systems. The complex is adjacent to their Carthage Hub, which delivers residue gas to interstate and intrastate pipelines. The Carthage Hub, with an aggregate delivery capacity of 1.5 billion cubic feet per day, acts as a key exchange point for the purchase and sale of residue gas. Discovery operates a 600 MMcf/d cryogenic natural gas processing plant near Larose, Louisiana, a 32,000 Bbl/d natural gas liquids fractionator plant near Paradis, Louisiana, a natural gas pipeline from offshore deep water in the Gulf of Mexico that transports gas to our processing plant in Larose, Louisiana with a design capacity of 600 MMcf/d and approximately 173 miles of pipe, and several laterals expanding their presence in the Gulf.

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):

Reconciliation of Non-GAAP Measures

	Six Months Ended June 30,		Year Ended December 31,		
	2007	2006	2006	2005	2004
			($ in millions)		
Reconciliation of net income to gross margin:					
Net income	$ 16.6	$ 32.0	$ 61.9	$ 69.8	$ 40.9
Add:					
Interest expense	8.4	5.2	11.5	0.8	—
Impairment of equity method investment	—	—	—	—	4.4
Income tax expense	—	—	—	3.3	2.5
Operating and maintenance expense	12.9	11.5	23.7	22.4	19.8
Depreciation and amortization expense	7.9	6.4	12.8	12.7	14.7
General and administrative expense	11.7	9.3	21.0	14.2	8.7
Less:					
Interest income	(2.5)	(3.0)	(6.3)	(0.5)	—
Earnings from equity method investments	(12.8)	(15.8)	(29.2)	(25.7)	(17.6)
Gross margin	$ 42.2	$ 45.6	$ 95.4	$ 97.0	$ 73.4
Reconciliation of segment net income (loss) to segment gross margin:					
Natural Gas Services segment:					
Segment net income	$ 23.7	$ 38.4	$ 79.6	$ 71.9	$ 45.5
Add:					
Depreciation and amortization expense	6.7	5.5	11.1	10.8	11.7
Operating and maintenance expense	7.2	7.0	13.5	14.0	13.4
Less: Earnings from equity method investments	(12.3)	(15.7)	(28.9)	(25.3)	(17.0)
Segment gross margin	$ 25.3	$ 35.2	$ 75.3	$ 71.4	$ 53.6
Wholesale Propane Logistics segment:					
Segment net income	$ 8.9	$ 3.7	$ 6.6	$ 12.6	$ 8.2
Add:					
Depreciation and amortization expense	0.4	0.5	0.8	1.0	2.1
Operating and maintenance expense	5.3	4.2	8.6	8.2	6.2
Segment gross margin	$ 14.6	$ 8.4	$ 16.0	$ 21.8	$ 16.5
NGL Logistics segment:					
Segment net income (loss)	$ 1.6	$ 1.4	$ 1.9	$ 3.1	$ (1.6)
Add:					
Depreciation and amortization expense	0.8	0.4	0.9	0.9	0.9
Operating and maintenance expense	0.4	0.3	1.6	0.2	0.2
Impairment of equity method investment	—	—	—	—	4.4
Less: Earnings from equity method investments	(0.5)	(0.1)	(0.3)	(0.4)	(0.6)
Segment gross margin	$ 2.3	$ 2.0	$ 4.1	$ 3.8	$ 3.3

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 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 six months ended June 30, 2007 and 2006, our general and administrative expense was $11.7 million and $9.3 million, respectively. For the years ended December 31, 2006, 2005 and 2004, our general and administrative expense was $21.0 million, $14.2 million and $8.7 million, respectively. We have entered into the Omnibus Agreement with DCP Midstream, LLC. Under the Omnibus Agreement, as amended, 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 of $4.8 million for services provided on our behalf related to the DCP Midstream Predecessor business contributed to us upon our initial public offering. The annual fee is 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 from DCP Midstream, LLC, subject to the same conditions noted above; (5) effective August 2007, includes an additional annual fee of $0.6 million to account for additional services provided to us; and (6) effective August 2007, includes an additional annual fee of $1.6 million related to our acquisition of certain subsidiaries of MEG from DCP Midstream, LLC, 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;
- 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 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.

Under our Omnibus Agreement with DCP Midstream, LLC, as amended, we will reimburse DCP Midstream, LLC $7.9 million for 2007, for the provision by DCP Midstream, LLC or its affiliates of various general and administrative services to us. For 2008, the fee will be increased by the percentage increase in the Consumer Price Index for the applicable year. In addition, our general partner will have the right to agree to further increases in connection with expansions of our operations through the acquisition or construction of new assets or businesses, with the concurrence of the special committee of DCP Midstream GP, LLC’s board of directors.

We incurred approximately $8.2 million and $6.9 million, and $15.9 million, $13.9 million and $8.7 million of other general and administrative expense during the six months ended June 30, 2007 and 2006, and during the years ending December 31, 2006, 2005 and 2004, 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 $3.5 million and $2.4 million, and $5.1 million, $0.3 million and $0 million for the six months ended June 30, 2007 and 2006, and for the years ended December 31, 2006, 2005 and 2004, respectively, per the Omnibus Agreement, as amended, 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 on 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:

Reconciliation of Non-GAAP Measures

	Six Months Ended June 30,		Year Ended December 31,		
	2007	2006	2006	2005	2004
			($ in millions)		
Reconciliation of net income to EBITDA:					
Net income	$ 16.6	$ 32.0	$ 61.9	$ 69.8	$ 40.9
Interest income	(2.5)	(3.0)	(6.3)	(0.5)	—
Interest expense	8.4	5.2	11.5	0.8	—
Income tax expense	—	—	—	3.3	2.5
Depreciation and amortization expense	7.9	6.4	12.8	12.7	14.7
EBITDA	$ 30.4	$ 40.6	$ 79.9	$ 86.1	$ 58.1
Reconciliation of net cash provided by operating activities to EBITDA:					
Net cash provided by operating activities	$ 39.8	$ 38.0	$ 94.8	$113.0	$ 38.1
Interest income	(2.5)	(3.0)	(6.3)	(0.5)	—
Interest expense	8.4	5.2	11.5	0.8	—
Earnings from equity method investments	12.8	15.8	29.2	25.7	17.6
Distributions from equity method investments	(18.5)	(11.1)	(25.9)	(36.7)	(13.4)
Income tax expense	—	—	—	3.3	2.5
Non-cash impairment of equity method investment	—	—	—	—	(4.4)
Net changes in operating assets and liabilities	(10.0)	(5.7)	(25.8)	(19.9)	17.4
Other, net	0.4	1.4	2.4	0.4	0.3
EBITDA	$ 30.4	$ 40.6	$ 79.9	$ 86.1	$ 58.1

Critical Accounting Policies and Estimates

Our financial statements reflect the selection and application of accounting policies that require management to make estimates and assumptions. We believe that the following are the more critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations.

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 recognize revenues for sales and services under the four revenue recognition criteria, as follows:

- *Persuasive evidence of an arrangement exists* — Our customary practice is to enter into a written contract, executed by both us and the customer.
- *Delivery* — Delivery is deemed to have occurred at the time custody is transferred, or in the case of fee-based arrangements, when the services are rendered. To the extent we retain product as inventory, delivery occurs when the inventory is subsequently sold and custody is transferred to the third party purchaser.
- *The fee is fixed or determinable* — We negotiate the fee for our services at the outset of our fee-based arrangements. In these arrangements, the fees are nonrefundable. For other arrangements, the amount of revenue, based on contractual terms, is determinable when the sale of the applicable product has been completed upon delivery and transfer of custody.
- *Collectability is probable* — Collectability is evaluated on a customer-by-customer basis. New and existing customers are subject to a credit review process, which evaluates the customers' financial position (for example, cash position and credit rating) and their ability to pay. If collectability is not considered probable at the outset of an arrangement in accordance with our credit review process, revenue is recognized when the fee is collected.

We generally report revenues gross in the 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. We recognize revenues from non-trading derivative activity net in the consolidated statements of operations. 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. We recognize revenues from non-trading derivative activity net in the consolidated statements of operations as (losses) gains from non-trading derivative activity. These activities include mark-to-market gains and losses on energy trading contracts, and the financial or physical settlement of energy trading contracts.

Inventories — Inventories, which consist primarily of propane, are recorded at the lower of weighted-average cost or market value. Transportation costs are included in inventory.

Gas and NGL Imbalance Accounting — Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements with customers, producers or pipelines are recorded monthly as other receivables or other payables using current market prices or the weighted-average prices of natural gas or NGLs at the plant or system. These balances are settled with deliveries of natural gas or NGLs, or with cash.

Goodwill — Goodwill is the cost of an acquisition less the fair value of the net assets of the acquired business. We evaluate goodwill for impairment annually in the third quarter, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Impairment testing of goodwill consists of a two-step process. The first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of the reporting unit exceeds its fair value, the second step of the process involves comparing the fair value and carrying value of the goodwill of that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the fair value of that goodwill, an impairment loss is recognized in an amount equal to the excess.

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

- significant adverse changes in legal factors or in the business climate;
- a current-period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- significant adverse changes in the extent or manner in which an asset is used, or in its physical condition;
- a significant adverse change in the market value of an asset; or
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

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

Impairment of Equity Method Investments — We evaluate our equity method investments for impairment whenever events or changes in circumstances indicate, in management's judgment, that the carrying value of such investment may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. We assess the fair value of our equity method investments using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales, internally developed discounted cash flow analysis and analysis from outside advisors. If the estimated fair value is less than the carrying value and we consider the decline in value to be other than temporary, we recognize an impairment for the excess of the carrying value over the estimated fair value.

Accounting for Risk Management and Hedging Activities and Financial Instruments — Each derivative not qualifying for the normal purchases and normal sales exception is recorded on a gross basis in the consolidated balance sheets at its fair value as unrealized gains or unrealized losses on non-trading derivative and hedging instruments. Derivative assets and liabilities remain classified in our consolidated balance sheets as unrealized gains or unrealized losses on non-trading derivative and hedging instruments at fair value until the contractual settlement period impacts earnings.

We designate each energy commodity derivative as either trading or non-trading. Prior to July 1, 2007, certain non-trading derivatives were further designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or normal purchases or normal sales, while certain non-trading derivatives, which are related to asset-based activities, are designated as non-trading activity. 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. For a complete discussion of our hedging policies, see Note 2 of the Notes to Consolidated Financial Statements in "Consolidated Financial Statements."

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

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

Accounting for Equity-Based Compensation — We adopted a long-term incentive plan, which permits for the grant of restricted units, phantom units, unit options and substitute awards, as described further in Note 2 and Note 14 of the Notes to Consolidated Financial Statements in "Consolidated Financial Statements." Equity-based compensation expense is accounted for over the vesting period of the related awards. We estimate the fair value of each award, and the number of awards that will ultimately vest at the end of each service period. These estimates are based on the tenure of our employees and the achievement of certain performance targets over the performance period. If actual results are not consistent with our assumptions and judgments, we may experience material changes in compensation expense.

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the six month ended June 30, 2007 and 2006, and for the years ended December 31, 2006, 2005 and 2004. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Six Months Ended June 30,		Year Ended December 31,		
	2007	2006	2006	2005	2004
	($ in millions except operating data)				
Operating revenues:					
Natural Gas Services (a)	$ 187.7	$ 212.4	$ 415.3	$ 592.8	$ 353.3
Wholesale Propane Logistics	227.0	210.5	375.2	359.8	324.5
NGL Logistics	3.6	2.6	5.3	191.7	156.2
Total operating revenues	418.3	425.5	795.8	1,144.3	834.0
Gross margin (b):					
Natural Gas Services	25.3	35.2	75.3	71.4	53.6
Wholesale Propane Logistics	14.6	8.4	16.0	21.8	16.5
NGL Logistics	2.3	2.0	4.1	3.8	3.3
Total gross margin	42.2	45.6	95.4	97.0	73.4
Operating and maintenance expense	12.9	11.5	23.7	22.4	19.8
General and administrative expense	11.7	9.3	21.0	14.2	8.7
Earnings from equity method investments (c)(d)	(12.8)	(15.8)	(29.2)	(25.7)	(17.6)
Impairment of equity method investment (e)	—	—	—	—	4.4
EBITDA (f)	30.4	40.6	79.9	86.1	58.1
Depreciation and amortization expense	7.9	6.4	12.8	12.7	14.7
Interest income	(2.5)	(3.0)	(6.3)	(0.5)	—
Interest expense	8.4	5.2	11.5	0.8	—
Income tax expense	—	—	—	3.3	2.5
Net income	$ 16.6	$ 32.0	$ 61.9	$ 69.8	$ 40.9
Operating data:					
Natural gas throughput (MMcf/d) (d)	716	656	666	629	590
NGL gross production (Bbls/d) (d)	20,207	19,378	19,485	17,562	16,815
Propane sales volume (Bbls/d)	25,715	24,664	21,259	22,604	24,589
NGL pipelines throughput (Bbls/d) (c)	27,917	23,947	25,040	20,565	20,222

(a) Includes the effect of the acquisition of the Swap entered into by DCP Midstream, LLC in March 2007. The Swap is for a total of approximately 1.9 million barrels at $66.72 per barrel, and reduced revenues by $8.7 million for the six months ended June 30, 2007.

(b) 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.

(c) Includes 45% of the throughput volumes and earnings of Black Lake subsequent to December 7, 2005. Prior to December 7, 2005, we owned a 50% interest in Black Lake.

(d) Includes 25% of the throughput volumes and earnings of East Texas and 40% of the throughput volumes and earnings of Discovery, as well as the amortization of the net difference between the carrying amount of Discovery and the underlying equity of Discovery, for all periods presented.

(e) Represents an impairment of our equity interest in Black Lake.

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

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

Total Operating Revenues — Total operating revenues decreased $7.2 million, or 2%, to $418.3 million in 2007 from $425.5 million in 2006, primarily due to the following:

- $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
- $12.8 million decrease related to commodity hedging and non-trading derivative activity; offset by
- $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.

Gross Margin — Gross margin decreased $3.4 million, or 7%, to $42.2 million in 2007 from $45.6 million in 2006, primarily due to the following:

- $9.9 million decrease for our Natural Gas Services segment primarily due 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; offset by
- $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
- $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.

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 decreased $3.0 million, or 19%, to $12.8 million in 2007 from $15.8 million in 2006, due to a decrease in equity earnings of $1.0 million from Discovery and $2.4 million from East Texas, offset by an increase in equity earnings of $0.4 million from Black Lake.

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.

Year Ended December 31, 2006 vs. Year Ended December 31, 2005

Total Operating Revenues — Total operating revenues decreased $348.5 million, or 30%, to $795.8 million in 2006 from $1,144.3 million in 2005, primarily due to the following:

- $190.3 million decrease primarily attributable to lower sales for our Seabreeze pipeline, primarily due to a change in contract terms in December 2005, between DCP Midstream, LLC and us, from a purchase and sale arrangement to a fee-based contractual transportation arrangement for our NGL Logistics segment; and
- $181.3 million decrease attributable primarily to lower natural gas prices and sales volumes, and an amendment to a contract with an affiliate, which resulted in a prospective change in the reporting of certain Pelico revenues from a gross presentation to a net presentation, partially offset by an increase in NGL and condensate prices and sales volumes for our Natural Gas Services segment; offset by

- $15.2 million increase attributable to higher propane prices, which were offset by lower sales volumes for our Wholesale Propane Logistics segment;
- $4.7 million increase in transportation revenue primarily attributable to an increase in volumes and a change in contract terms in December 2005 for our Seabreeze pipeline, from a purchase and sale arrangement to a fee-based contractual transportation arrangement; and
- $3.2 million increase related to commodity hedging and non-trading derivative activity.

Gross Margin — Gross margin decreased $1.6 million, or 2%, to $95.4 million in 2006 from $97.0 million in 2005, primarily due to the following:

- $5.8 million decrease due to non-cash lower of cost or market inventory adjustments, decreased sales volumes, and increased product and transportation costs for our Wholesale Propane Logistics segment; offset by
- $3.9 million increase for our Natural Gas Services segment primarily due to higher NGL and condensate prices, and an increase in natural gas throughput volumes, offset by lower natural gas prices, decreases due to a change in contract mix, and decreased marketing activity and throughput across the Pelico system due to atypical differences in natural gas prices at various receipt and delivery points across the system, which impacted gross margin more significantly in 2005 than in 2006. The market conditions causing the differentials in natural gas prices at various receipt and delivery points may not continue in the future, nor can we assure our ability to capture upside margin if these market conditions do occur; and
- $0.3 million increase attributable to increased transportation revenue and higher volumes on our Seabreeze pipeline for our NGL Logistics segment.

Operating and Maintenance Expense — Operating and maintenance expense increased $1.3 million, or 6%, to $23.7 million in 2006 from $22.4 million in 2005, primarily as a result of higher pipeline integrity costs, increased labor and benefit costs, an increase in lease expense and the settlement of a commercial dispute.

General and Administrative Expense — General and administrative expense increased $6.8 million, or 48%, to $21.0 million in 2006 from $14.2 million in 2005, primarily as a result of increased audit fees, due diligence and acquisition costs, costs incurred related to the Sarbanes-Oxley Act of 2002, labor and benefit costs, and insurance premiums.

Earnings from Equity Method Investments — Earnings from equity method investments increased $3.5 million, or 14%, to $29.2 million in 2006 from $25.7 million in 2005, primarily due to an increase in equity earnings of $6.1 million from Discovery, offset by a decrease in equity earnings of $2.5 million from East Texas and $0.1 million from Black Lake.

Depreciation and Amortization Expense — Depreciation and amortization expense was relatively constant in 2006 and 2005.

Income Tax Expense — We incurred no income tax expense in 2006, due to the change in tax status of our wholesale propane logistics business in December 2005. See Note 15 of the Notes to Consolidated Financial Statements in “Consolidated Financial Statements.”

Year Ended December 31, 2005 vs. Year Ended December 31, 2004

Total Operating Revenues — Total operating revenues increased $310.3 million, or 37%, to $1,144.3 million in 2005 from $834.0 million in 2004, primarily due to the following:

- $237.4 million increase attributable primarily to higher commodity prices and natural gas sales volumes for our Natural Gas Services segment;
- $35.2 million increase primarily attributable to higher NGL prices and increased throughput for our Seabreeze pipeline;
- $34.1 million increase attributable primarily to higher propane prices, which were partially offset by lower sales volumes for our Wholesale Propane Logistics segment;
- $2.6 million increase in transportation revenue; and
- $1.0 million increase related to commodity hedging and non-trading derivative activity.

Gross Margin — Gross margin increased $23.6 million, or 32%, to $97.0 million in 2005 from $73.4 million in 2004, primarily as a result of the following:

- $17.8 million increase attributable primarily to higher commodity prices and an increase in marketing activity and increased throughput across the Pelico system due to atypical and significant differences in natural gas prices at various receipt and delivery points across the system for our Natural Gas Services segment. The market conditions causing these significant differences in the natural gas prices at various receipt and delivery points across the

Pelico system are unusual and may not continue in the future, and we may not be able to capture the upside related to this market condition in the future;

- $5.3 million increase due to increased prices and an increase related to commodity hedging, partially offset by lower sales volumes and increased product and transportation costs for our Wholesale Propane Logistics segment; and
- $0.5 million increase due to increased throughput volumes for our Seabreeze pipeline.

Impact of Hurricanes Katrina and Rita — Hurricanes Katrina and Rita caused extensive damage to the Texas, Louisiana and Mississippi Gulf Coast in late August and mid-September of 2005. These storms did not cause any significant damage to our properties. However, in September 2005, we experienced operational disruptions for several days as a result of the impact of Hurricane Rita on the energy industry in our areas of operations. These disruptions reduced our total operating revenues by approximately $10.1 million, our purchases by approximately $9.5 million and our gross margin by approximately $0.6 million in September 2005.

Operating and Maintenance Expense — Operating and maintenance expense increased $2.6 million, or 13%, to $22.4 million in 2005 from $19.8 million in 2004, primarily as a result of higher pipeline integrity costs, higher maintenance expenses, increased labor costs and higher lease expenses.

General and Administrative Expense — General and administrative expense increased $5.5 million, or 63%, to $14.2 million in 2005 from $8.7 million in 2004. This increase was primarily the result of public offering costs of approximately $4.0 million and higher allocated costs from DCP Midstream, LLC for general and administrative costs, primarily as a result of increased insurance premiums.

Earnings from Equity Method Investments — Earnings from equity method investments increased $8.1 million, or 46%, to $25.7 million in 2005 from $17.6 million in 2004, primarily due to an increase in equity earnings of $5.3 million from East Texas and an increase in equity earnings of $3.0 million from Discovery, offset by a decrease in equity earnings from Black Lake of $0.2 million.

Impairment of Equity Method Investment — In 2004, we recorded an impairment totaling $4.4 million of our equity interest in Black Lake, which is included in the NGL Logistics segment.

Depreciation and Amortization Expense — Depreciation and amortization expense decreased $2.0 million, or 14%, to $12.7 million in 2005 from $14.7 million in 2004 as a result of certain assets that became fully depreciated at the beginning of 2005.

Results of Operations — Natural Gas Services Segment

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

	Six Months Ended June 30,		Year Ended December 31,		
	2007	2006	2006	2005	2004
	($ in millions except operating data)				
Operating revenues:					
Sales of natural gas, NGLs and condensate	$ 189.7	$ 201.1	$ 391.8	$ 570.9	$ 333.5
Transportation and processing services	12.3	11.3	23.5	22.6	19.9
Losses from non-trading derivative activity (a)	(14.3)	—	—	(0.7)	(0.1)
Total operating revenues	187.7	212.4	415.3	592.8	353.3
Purchases of natural gas and NGLs	162.4	177.2	340.0	521.4	299.7
Segment gross margin (b)	25.3	35.2	75.3	71.4	53.6
Operating and maintenance expense	7.2	7.0	13.5	14.0	13.4
Depreciation and amortization expense	6.7	5.5	11.1	10.8	11.7
Earnings from equity method investments (c)	(12.3)	(15.7)	(28.9)	(25.3)	(17.0)
Segment net income	$ 23.7	$ 38.4	$ 79.6	$ 71.9	$ 45.5
Operating data:					
Natural gas throughput (MMcf/d) (c)	716	656	666	629	590
NGL gross production (Bbls/d) (c)	20,207	19,378	19,485	17,562	16,815

(a) Includes the effect of the acquisition of the Swap entered into by DCP Midstream, LLC in March 2007. The Swap is for a total of approximately 1.9 million barrels at $66.72 per barrel, and increased losses from non-trading derivative activity by $8.7 million for the six months ended June 30, 2007.

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

(c) Includes 25% of the throughput volumes and earnings of East Texas and 40% of the throughput volumes and earnings of Discovery, as well as the amortization of the net difference between the carrying amount of Discovery and the underlying equity of Discovery, for all periods presented.

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

Total Operating Revenues — Total operating revenues decreased $24.7 million, or 12%, to $187.7 million in 2007 from $212.4 million in 2006, primarily due to the following:

- $12.6 million decrease related to commodity hedging and non-trading derivative activity;
- $7.4 million decrease attributable to a decrease in commodity prices; and
- $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, partially as a result of the Southern Oklahoma asset acquisition; 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 $9.9 million, or 28%, to $25.3 million in 2007 from $35.2 million in 2006, primarily as a result of the following:

- $12.6 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
- $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 829 Bbls/d, or 4%, to 20,207 Bbls/d from 19,378 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 Discovery and at our Minden processing plant in 2007. Natural gas transported and/or processed during 2007 increased 60 MMcf/d, or 9%, to 716 MMcf/d from 656 MMcf/d in 2006 due primarily to increased volumes at Discovery.

Earnings from Equity Method Investments — Earnings from equity method investments decreased $3.4 million, or 22%, to $12.3 million in 2007 from $15.7 million in 2006, due to a decrease in equity earnings of $1.0 million from Discovery and a decrease in equity earnings of $2.4 million from East Texas. Decreased equity earnings were primarily the result of the following variances, each representing 100% of the earnings drivers for East Texas and Discovery:

- Decreased equity earnings from East Texas were the result of a decrease in East Texas’s net income of $9.6 million, or 34%, due primarily to a $2.1 million decrease due to natural gas volumes, a $2.8 million decrease due to decreased fee-based revenue, an increase in operating and maintenance expenses of $2.3 million, primarily due to increased contract services, materials and supplies, and labor and benefits and an increase in general and administrative expenses of $2.1 million, primarily due to higher allocated costs from DCP Midstream of $1.1 million due to higher overall DCP Midstream, LLC general and administrative expenses.
- Decreased equity earnings from Discovery were the result of a decrease in Discovery’s net income of $2.3 million, or 15%, due primarily to $10.7 million lower fee-based transportation, processing and fractionation revenues from the

absences of the 2006 Tennessee Gas Pipeline, or TGP, and Texas Eastern Transmission Company, or TETCO, open season agreements and $5.5 million higher operating and maintenance expense, largely offset by $13.8 million higher NGL margins on higher NGL sales volumes. The open seasons provided outlets for natural gas that was stranded following damage to third-party facilities during hurricanes Katrina and Rita. TGP's open season contract came to an end in early 2006.

Year Ended December 31, 2006 vs. Year Ended December 31, 2005

Total Operating Revenues — Total operating revenues decreased $177.5 million, or 30%, to $415.3 million in 2006 from $592.8 million in 2005, primarily due to the following:

- $114.1 million decrease attributable to a decrease in natural gas sales volumes and an amendment to a contract with an affiliate, which resulted in a prospective change in the reporting of certain Pelico revenues from a gross presentation to a net presentation; and
- $87.3 million decrease attributable to a decrease in natural gas prices; offset by
- $10.1 million increase primarily attributable to higher NGL and condensate sales volumes;
- $10.0 million increase attributable to an increase in NGL and condensate prices;
- $2.9 million increase related to commodity hedging and non-trading derivative activity; and
- $0.9 million increase in transportation revenue primarily attributable to an increase in natural gas throughput.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs decreased $181.4 million, or 35%, to $340.0 million in 2006 from $521.4 million in 2005, primarily due to lower costs of raw natural gas supply, driven by lower natural gas prices and decreased purchased volumes, and an amendment to a contract with an affiliate, which resulted in a prospective change in the reporting of certain Pelico purchases from a gross presentation to a net presentation, partially offset by higher NGL and condensate prices and NGL and condensate purchased volumes.

Segment Gross Margin — Segment gross margin increased $3.9 million, or 5%, to $75.3 million in 2006 from $71.4 million in 2005, primarily as a result of the following:

- $6.2 million increase attributable to higher NGL and condensate prices and favorable frac spreads, partially offset by lower natural gas prices. The frac spreads that existed during 2006 were higher than in recent years and may not continue in the future;
- $5.2 million increase primarily attributable to an increase in natural gas throughput volumes;
- $2.9 million increase related to commodity hedging and non-trading derivative activity; and
- $0.5 million increase attributable to higher contractual fees charged to customers related to pipeline imbalances; offset by
- $5.1 million decrease primarily attributable to a change in contract mix;
- $4.0 million decrease attributable to a decrease in marketing activity and throughput across our Pelico system due to atypical differences in natural gas prices at various receipt and delivery points across the system. The market conditions causing the differentials in natural gas prices may not continue in the future, nor can we assure our ability to capture upside margin if these market conditions do occur; and
- $1.8 million decrease attributable to higher netback prices paid to the producers at Minden and Ada.

Operating and Maintenance Expense — Operating and maintenance expense decreased $0.5 million, or 4%, to $13.5 million in 2006 from $14.0 million in 2005, primarily as a result of lower costs associated with repairs and maintenance.

NGL production during 2006 increased 1,923 Bbls/d, or 11%, to 19,485 Bbls/d from 17,562 Bbls/d in 2005, due primarily to increased volumes at Discovery and unfavorable market economics for processing NGLs in the fourth quarter of 2005. Natural gas transported and/or processed during 2006 increased 37 MMcf/d, or 6%, to 666 MMcf/d from 629 MMcf/d in 2005, primarily as a result of higher natural gas volumes at Discovery and for our Pelico system, offset by lower volumes at East Texas.

Earnings from Equity Method Investments — Earnings from equity method investments increased $3.6 million, or 14%, to $28.9 million in 2006 from $25.3 million in 2005, primarily due to an increase in equity earnings of $6.1 million from Discovery, partially offset by a decrease in equity earnings of $2.5 million from East Texas. Increased equity earnings were primarily the result of the following variances, each representing 100% of the earnings drivers for East Texas and Discovery:

- Decreased equity earnings from East Texas were the result of a decrease in East Texas's net income of $10.0 million, or 17%, due primarily to a $15.7 million decrease due to natural gas volumes and a $3.7 million decrease due to decreased fee-based revenue, offset by a $17.3 million increase due to increases in overall contract yield and higher condensate sales due to higher crude oil prices, an increase in operating and maintenance expenses of $4.2 million, primarily due to increased contract services, materials and supplies, and labor and benefits, an increase in general and administrative expenses of $1.6 million, primarily due to higher allocated costs from DCP

Midstream of $1.5 million due to higher overall DCP Midstream, LLC general and administrative expenses and an increase of $1.8 million in income tax expense due to recording deferred taxes in 2006 related to the Texas margin tax.

- Increased equity earnings from Discovery were the result of our purchase of an additional 6.67% interest in Discovery, as well as an increase in Discovery's net income of $9.3 million, or 44%, due primarily to $18.1 million higher gross processing margins and $7.5 million higher revenues from TGP and TETCO open seasons, partially offset by $12.9 million higher operating and maintenance and $3.8 million lower gathering revenues. The open seasons provided outlets for natural gas that was stranded following damage to third-party facilities during hurricanes Katrina and Rita. TGP's open season contract came to an end in early 2006.

Year Ended December 31, 2005 vs. Year Ended December 31, 2004

Total Operating Revenues — Total operating revenues increased $239.5 million, or 68%, to $592.8 million in 2005 from $353.3 million in 2004, primarily due to the following:

- $169.6 million increase attributable to an increase in natural gas prices;
- $15.0 million increase attributable to an increase in NGL and condensate prices;
- $52.8 million increase attributable to higher natural gas sales volumes driven primarily by incremental natural gas demand at our Minden and Ada processing plants related to our merchant arrangements, higher gas supply volumes for our Ada processing plant and gathering system and an increase in marketing activity and increased throughput across the Pelico system due to atypical and significant differences in natural gas prices at various receipt and delivery points across the system. The market conditions causing these significant differences in the natural gas prices at various receipt and delivery points across the Pelico system are unusual and may not continue in the future, and we may not be able to capture the upside related to the market condition in the future; and
- $2.7 million increase attributable to higher processing fees primarily driven by incremental fee-based services of our Ada gathering system and higher transportation fees primarily driven by an increase in volumes on our Pelico system; offset by
- $0.6 million decrease attributable to lower non-trading derivative activity.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs increased $221.7 million, or 74%, to $521.4 million in 2005 from $299.7 million in 2004, primarily due to higher costs of raw natural gas supply driven by higher commodity prices.

Segment Gross Margin — Segment gross margin increased $17.8 million, or 33%, to $71.4 million in 2005 from $53.6 million in 2004, primarily as a result of the following:

- $9.3 million increase attributable to an increase in marketing activity and increased throughput across the Pelico system due to atypical and significant differences in natural gas prices at various receipt and delivery points across the system. The market conditions causing the differentials in natural gas prices may not continue in the future, nor can we assure our ability to capture upside margin if these market conditions do occur;
- $8.7 million increase attributable to higher commodity prices; and
- $2.7 million increase attributable to higher processing fees primarily driven by incremental fee-based services of our Ada gathering system and higher transportation fees primarily driven by an increase in volumes on our Pelico system; offset by
- $2.3 million decrease attributable to lower contractual fees charged to customers related to pipeline imbalances and a decrease in NGL recoveries at Minden as a result of unfavorable processing economics in the fourth quarter of 2005; and
- $0.6 million decrease attributable to lower non-trading derivative activity.

Operating and Maintenance Expense — Operating and maintenance expense increased $0.6 million, or 4%, to $14.0 million in 2005 from $13.4 million in 2004, primarily as a result of higher outside services, parts, supplies and labor for maintenance and higher costs for pipeline integrity testing.

NGL production during 2005 increased 747 Bbls/d, or 4%, to 17,562 Bbls/d from 16,815 Bbls/d in 2004 due primarily to increased volumes at East Texas, offset by unfavorable market economics for processing NGLs in the fourth quarter of 2005. Natural gas transported and/or processed during 2005 increased 39 MMcf/d, or 7%, to 629 MMcf/d from 590 MMcf/d in 2004, primarily as a result of higher natural gas volumes for our Pelico system and East Texas.

Earnings from Equity Method Investments — Earnings from equity method investments increased $8.3 million, or 49%, to $25.3 million in 2005 from $17.0 million in 2004, primarily due to an increase in equity earnings of $5.3 million from East Texas and an increase in equity earnings of $3.0 million from Discovery. Increased equity earnings were primarily the result of the following variances, each representing 100% of the earnings drivers for East Texas and Discovery:

- Increased equity earnings from East Texas were the result of an increase in East Texas's net income of $20.8 million, or 56%, due primarily to a $8.5 million increase due to increased natural gas volumes, a $7.1 million increase due to increased commodity prices, a $5.4 million increase due to increased fee-based revenue, and a $6.4 million increase due to increases in overall contract yield, partially offset by an increase in trading and marketing losses of $1.6 million, an increase in operating and maintenance expenses of $3.9 million, primarily due to increased contract services, materials and supplies, and labor and benefits and an increase in general and administrative expenses of $1.5 million, primarily due to higher allocated costs from DCP Midstream of $1.7 million due to higher overall DCP Midstream, LLC general and administrative expenses.

- Increased equity earnings from Discovery were the result of the increase in Discovery's net income of $9.2 million, or 78%, due primarily to the $10.7 million deferred gain recognition related to amounts deferred for net system gains from 2002 through 2004 that were recognized following the acceptance in 2005 of a filing with the Federal Energy Regulatory Commission, $8.9 million increased revenue from gathering, processing and fractionation services and $1.1 million higher interest income, partially offset by $3.5 million lower product sales margins, $3.0 million higher other operating and maintenance expense, $0.6 million higher general and administrative expense, $2.0 million higher depreciation and accretion and $0.8 higher other expense including the foreign currency transaction loss.

Results of Operations — Wholesale Propane Logistics Segment

This segment includes our propane transportation facilities, which includes six owned propane rail terminals, one leased propane marine terminal, one pipeline terminal, and access to several open-access pipeline terminals.

	Six Months Ended June 30,		Year Ended December 31,		
	2007	2006	2006	2005	2004
	($ in millions except operating data)				
Operating revenues:					
Sales of propane	$ 227.7	$ 211.0	$ 375.0	$ 359.8	$ 325.7
Transportation and processing services	—	—	0.1	0.2	0.6
(Losses) gains from non-trading derivative activity	(0.7)	(0.5)	0.1	(0.2)	(1.8)
Total operating revenues	227.0	210.5	375.2	359.8	324.5
Purchases of propane	212.4	202.1	359.2	338.0	308.0
Segment gross margin (a)	14.6	8.4	16.0	21.8	16.5
Operating and maintenance expense	5.3	4.2	8.6	8.2	6.2
Depreciation and amortization expense	0.4	0.5	0.8	1.0	2.1
Segment net income	$ 8.9	$ 3.7	$ 6.6	$ 12.6	$ 8.2
Operating Data:					
Propane sales volume (Bbls/d)	25,715	24,664	21,259	22,604	24,589

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

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.

Year Ended December 31, 2006 vs. Year Ended December 31, 2005

Total Operating Revenues — Total operating revenues increased $15.4 million, or 4%, to $375.2 million in 2006 from $359.8 million in 2005, primarily due to the following:

- $36.6 million increase attributable to higher propane prices; and
- $0.3 million increase related to non-trading derivative activity; offset by
- $21.4 million decrease attributable to lower propane sales volumes; and
- $0.1 million decrease in transportation revenues.

Purchases of Propane — Purchases of propane increased $21.2 million, or 6%, to $359.2 million in 2006 from $338.0 million 2005, primarily due to increased product and transportation costs, and non-cash lower of cost or market inventory adjustments partially offset by a decrease in volume.

Segment Gross Margin — Segment gross margin decreased $5.8 million, or 27%, to $16.0 million in 2006 from $21.8 million in 2005, primarily as a result of decreased sales volumes, non-cash lower of cost or market inventory adjustments, and increased product and transportation costs.

Operating and Maintenance Expense — Operating and maintenance expense increased $0.4 million, or 5%, to $8.6 million in 2006 from $8.2 million in 2005, primarily as a result of higher labor costs and an increase in lease expenses.

Propane sales decreased 1,345 Bbls/d, or 6%, to 21,259 Bbls/d in 2006 from 22,604 Bbls/d in 2005, due primarily to milder weather in the northeastern United States in 2006.

Year Ended December 31, 2005 vs. Year Ended December 31, 2004

Total Operating Revenues — Total operating revenues increased $35.3 million, or 11%, to $359.8 million in the 2005 from $324.5 million in 2004, primarily due to the following:

- $60.4 million increase attributable to higher propane prices; and
- $1.6 million increase related to non-trading derivative activity; offset by
- $26.3 million decrease attributable to lower propane sales volumes; and
- $0.4 million decrease in transportation revenues.

Purchases of Propane — Purchases of propane increased $30.0 million, or 10%, to $338.0 million in 2005 from $308.0 million 2004, primarily due to increased product and transportation costs, partially offset by a decrease in volume.

Segment Gross Margin — Segment gross margin increased $5.3 million, or 32%, to $21.8 million in 2005 from $16.5 million in 2004, primarily as a result of increased per unit margins and an increase related to commodity hedging, partially offset by lower sales volumes, and increased product and transportation costs.

Operating and Maintenance Expense — Operating and maintenance expense increased $2.0 million, or 32%, to $8.2 million in 2005 from $6.2 million in 2004, primarily due to an increase in lease expenses as a result of the commencement of a new lease arrangement.

Depreciation and Amortization Expense — Depreciation and amortization expense decreased $1.1 million, or 52%, to $1.0 million in 2005 from $2.1 million in 2004, primarily as a result of certain assets that became fully depreciated at the beginning of 2005.

Propane sales decreased 1,985 Bbls/d, or 8%, to 22,604 Bbls/d in 2005 from 24,589 Bbls/d in 2004.

Results of Operations — NGL Logistics Segment

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

	Six Months Ended June 30,		Year Ended December 31,		
	2007	2006	2006	2005	2004
	($ in millions except operating data)				
Operating revenues:					
Sales of NGLs	$ 1.1	$ 0.5	$ 1.1	$ 191.4	$ 156.2
Transportation and processing services	2.5	2.1	4.2	0.3	—
Total operating revenues	3.6	2.6	5.3	191.7	156.2
Purchases of NGLs	1.3	0.6	1.2	187.9	152.9
Segment gross margin (a)	2.3	2.0	4.1	3.8	3.3
Operating and maintenance expense	0.4	0.3	1.6	0.2	0.2
Earnings from equity method investment (b)	(0.5)	(0.1)	(0.3)	(0.4)	(0.6)
Impairment of equity method investment	—	—	—	—	4.4
Depreciation and amortization expense	0.8	0.4	0.9	0.9	0.9
Segment net income	$ 1.6	$ 1.4	$ 1.9	$ 3.1	$ (1.6)
Operating data:					
NGL pipelines throughput (Bbls/d) (b)	27,917	23,947	25,040	20,565	20,222

(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 in 2006 and the period from December 7, 2005 through December 31, 2005. Prior to December 7, 2005, we owned a 50% interest in Black Lake.

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.

Year Ended December 31, 2006 vs. Year Ended December 31, 2005

Total Operating Revenues — Total operating revenues decreased $186.4 million, or 97%, to $5.3 million in 2006 from $191.7 million in 2005, primarily due to the following:

- $190.3 million decrease primarily attributable to lower sales for our Seabreeze pipeline primarily due to a change in contract terms in December 2005, between DCP Midstream, LLC and us, from a purchase and sale arrangement to a fee-based contractual transportation agreement; offset by
- $3.9 million increase in transportation revenue attributable to an increase in volumes and a change in contract terms in December 2005, from a purchase and sale arrangement to a fee-based contractual transportation arrangement.

Overall, our NGL pipelines experienced an increase in throughput volumes during 2006 as compared to 2005, partially as result of a decrease in September 2005 volumes related to the impact of hurricane Katrina.

Purchases of NGLs — Purchases of NGLs decreased $186.7 million, or 99%, to $1.2 million in 2006 from $187.9 million 2005, attributable to lower purchases due to the change in contract terms in December 2005 from a purchase and sale arrangement to a fee-based contractual transportation arrangement.

Segment Gross Margin — Segment gross margin increased $0.3 million, or 8%, to $4.1 million in 2006 from $3.8 million in 2005, primarily due to increased transportation revenue and higher volumes on our Seabreeze pipeline.

Operating and Maintenance Expense — Operating and maintenance expense increased $1.4 million, to $1.6 million in 2006 from $0.2 million in 2005, primarily as a result of higher costs associated with asset integrity, the settlement of a commercial dispute, and equipment rentals.

Earnings from Equity Method Investment — Earnings from equity method investment remained relatively constant in 2006 and 2005.

Year Ended December 31, 2005 vs. Year Ended December 31, 2004

Total Operating Revenues — Total operating revenues increased $35.5 million, or 23%, to $191.7 million in the 2005 from $156.2 million in 2004, primarily due to the following:

- $39.7 million increase attributable to higher NGL prices for our Seabreeze pipeline; and
- $0.3 million increase in transportation revenue attributable to the change in contract terms in December 2005, from a purchase and redeliver arrangement to a fee-based transport contractual arrangement; offset by
- $4.5 million decrease attributable to lower sales volume for our Seabreeze pipeline primarily due to a change in contract terms in December 2005, from a purchase and sale arrangement to a fee-based contractual arrangement.

Overall, our Seabreeze pipeline experienced an increase in throughput volumes during 2005 as a result of a temporary disruption in supply from a third party pipeline in March 2004, which was restored in June 2005.

Purchases of NGLs — Purchases of NGLs increased $35.0 million, or 23%, to $187.9 million in 2005 from $152.9 million 2004, primarily due to the following:

- $39.7 million increase attributable to higher NGL prices for our Seabreeze pipeline; offset by
- $4.7 million decrease attributable to the change in contract terms in December 2005 from a purchase and sale arrangement to a fee-based contractual transportation arrangement.

Segment Gross Margin — Segment gross margin increased $0.5 million, or 15%, to $3.8 million in 2005 from $3.3 million in 2004 mainly as a result of higher volumes on our Seabreeze pipeline.

Earnings from Equity Method Investment — Earnings from equity method investment decreased $0.2 million, to $0.4 million in 2005 from $0.6 million in 2004, primarily due to an increase in Black Lake operating costs as a result of pipeline integrity testing during the fourth quarter of 2005.

Impairment of Equity Method Investment — In 2004, we recorded an impairment of our equity investment in Black Lake totaling $4.4 million. We did not record an impairment in 2005.

Liquidity and Capital Resources

Our Predecessor's sources of liquidity, prior to their acquisition by us, included cash generated from operations and funding from DCP Midstream, LLC. Our Predecessor's cash receipts were deposited in DCP Midstream, LLC's bank accounts and all cash disbursements were made from these accounts. Cash transactions for our Predecessors were handled by DCP Midstream, LLC and were reflected in partners' equity as intercompany advances from DCP Midstream, LLC. Following the acquisition of our Predecessor operations, we maintain our own bank accounts, which are managed by DCP Midstream, LLC.

We expect our sources of liquidity to include:

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

We anticipate our more significant uses of resources to include:

- capital expenditures
- business and asset 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 that were executed prior to our initial public offering, 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" and "Quantitative and Qualitative Disclosures about Market Risk."

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 $52.5 million, $33.1 million, $60.1 million and $41.2 million as of June 30, 2007, and December 31, 2006, 2005 and 2004, 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, and for the years ended December 31, 2006, 2005 and 2004 were as follows:

	Six Months Ended June 30,		Year Ended December 31,		
	2007	2006	2006	2005	2004
			($ in millions)		
Net cash provided by operating activities	$ 39.8	$ 38.0	$ 94.8	$ 113.0	$ 38.1
Net cash used in investing activities	$(99.3)	$(20.4)	$(93.8)	$(130.4)	$ (2.6)
Net cash provided by (used in) financing activities	$ 68.3	$(39.5)	$ 3.0	$ 59.6	$(35.5)

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 consolidated statements of cash flows and changes in working capital as discussed above.

We received cash distributions from equity method investments of $18.5 million and $11.1 million during the six months ended June 30, 2007 and 2006, respectively, and $25.9 million, $36.7 million, and $13.4 million, during the years ended December 31, 2006, 2005 and 2004, respectively. Distributions exceeded earnings by $5.7 million for the six months ended June 30, 2007 and earnings exceeded distributions by $4.7 million for the six months ended June 30, 2006. Distributions exceeded earnings by $11.0 million for the year ended December 31, 2005, and earnings exceeded distributions by $3.3 million for the year ended December 31, 2006 and $4.2 million for the year ended December 31, 2004.

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; (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; and (3) investments in Discovery of $3.9 million; which were partially offset by (4) 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, investments in Discovery and net purchases of available-for-sale securities.

During the year ended December 31, 2006, we acquired our wholesale propane logistics business from DCP Midstream, LLC, for an initial cash outlay of approximately $67.4 million. The historical value of the assets acquired of approximately $56.7 million is reflected in “net cash used in investing activities.” The remaining $10.7 million is reflected in “net cash provided by (used in) financing activities” as the excess of the purchase price over the acquired assets.

Net cash used in investing activities during the year ended December 31, 2005 primarily consisted of purchases of available-for-sale securities in the amount of $100.1 million to provide collateral for the term loan portion of our credit facility. Net cash used in investing activities from 2004 through 2006 was also used for capital expenditures, which generally consisted of expenditures for construction and expansion of our infrastructure in addition to well connections and other upgrades to our existing facilities.

We invested cash in unconsolidated affiliates of $11.1 million and $20.5 million during the years ended December 31, 2006 and 2005, respectively, of which $11.1 million and $7.6 million, respectively, was made to fund our share of a capital expansion project, and $12.9 million in 2005 was for the purchase of an additional 6.67% ownership interest in Discovery.

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 the 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, changes in advances from DCP Midstream, LLC of $14.6 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 advances from DCP Midstream, LLC and distributions to our unitholders.

Net cash provided by financing activities during the year ended December 31, 2006 was primarily comprised of borrowings on our credit facility, which we used to fund the acquisition of our wholesale propane logistics business, partially offset by distributions to our unit holders, repayments of debt, changes in parent advances and the excess purchase price of our wholesale propane logistics business over its historical basis. Net cash provided by financing activities during the year ended December 31, 2005 was a result of proceeds from the issuance of common units, proceeds from borrowings on our credit facility, partially offset by related distributions to DCP Midstream, LLC and changes in advances from DCP Midstream, LLC. Net cash provided by (used in) financing activities from 2004 through 2005 represents the pass through of our net cash flows to DCP Midstream, LLC under its cash management program as discussed above. We expect to incur future financing cash outflows as a result of distributions to our unitholders and general partner. See Note 12 of the Notes to Consolidated Financial Statements in “Consolidated 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. 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. In conjunction with the acquisition of our investments in East Texas and Discovery, we entered into an agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse East Texas for 25%, and will reimburse us for 40%, of certain capital expenditures as defined in the agreement, from July 1, 2007 through completion of the capital projects, for a period not to exceed three years. During the year ended December 31, 2006, our capital expenditures totaled $27.2 million, including maintenance capital expenditures of $2.2 million and expansion capital expenditures of $25.0 million. In the second quarter of 2006, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC made capital contributions to reimburse us for certain capital projects. We also have an agreement with certain producers whereby these producers will reimburse us for certain capital projects completed by us. As a result, during the year ended December 31, 2006, we had changes in receivables and collections of maintenance capital expenditures, from DCP Midstream, LLC and producers, of approximately $0.4 million. As a result, our total maintenance capital expenditures net of reimbursements were approximately $1.8 million for the year ended December 31, 2006. 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.

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 made cash distributions to our unitholders of $22.1 million during 2006. 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 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. In July 2007 we borrowed $245.9 million from our revolving credit facility to finance the acquisition of our interests in East Texas and Discovery. In August 2007 we borrowed $100.0 million from our term loan facility and $20.0 million from our revolving credit facility to finance the MEG acquisition. As of September 28, 2007, the outstanding balance on the revolving credit facility was $530.0 million and the outstanding balance on the term loan facility was $100.0 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 consolidated balance sheets, 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 consolidated balance sheets. Purchase obligations also exclude current and long-term unrealized losses on non-trading derivative and hedging instruments included on the consolidated balance sheets, 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 consolidated balance sheet.

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

Recent Accounting Pronouncements

New Accounting Standards

***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.

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

***Emerging Issues Task Force Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty,* or EITF 04-13** — In September 2005, the FASB ratified the EITF's consensus on Issue 04-13, which requires an entity to treat sales and purchases of inventory between the entity and the same counterparty as one transaction for purposes of applying APB Opinion No. 29, *Accounting for Nonmonetary Transactions,* or APB 29, when such transactions are entered into in contemplation of each other. When such transactions are legally contingent on each other, they are considered to have been entered into in contemplation of each other. The EITF also agreed on other factors that should be considered in determining whether transactions have been entered into in contemplation of each other. EITF 04-13 was applied to new arrangements that we entered into after March 31, 2006. The adoption of EITF 04-13 did not have a material impact on our consolidated results of operations, cash flows or financial position.

***Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements,* or SAB 108** — In September 2006, the SEC issued SAB 108 to address diversity in practice in quantifying financial statement misstatements. SAB 108 requires entities to quantify misstatements based on their impact on each of their financial statements and related disclosures. SAB 108 is effective as of the end of our 2006 fiscal year, allowing a one-time transitional cumulative effect adjustment to retained earnings as of January 1, 2006 for errors that were not previously deemed material, but are material under the guidance in SAB 108. The adoption of SAB 108 did not have a material impact on our consolidated results of operations, cash flows or financial position.

Quantitative and Qualitative Disclosures about Market Risk

Market risk is the risk of loss arising from adverse change in market prices and rates. We are exposed to market risks, including changes in commodity prices and interest rates. We may use financial instruments such as forward contracts, swaps and futures to mitigate the effects of identified risks. In general, we attempt to mitigate risks related to the variability of future earnings and cash flows resulting from changes in applicable commodity prices or interest rates so that we can maintain cash flows sufficient to meet debt service, required capital expenditures, distribution objectives and similar requirements.

Risk Management Policy

Management has established a comprehensive risk management policy, or the Risk Management Policy, as amended, and a risk management committee, or the Risk Management Committee, to monitor and manage market risks associated with commodity prices, counterparty credit. Our Risk Management Committee is composed of senior executives who receive regular briefings on positions and exposures, credit exposures and overall risk management in the context of market activities. The Risk Management Committee, which was formed effective February 8, 2006, is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. Prior to the formation of the Risk Management Committee, we utilized DCP Midstream, LLC's risk management policies and procedures and risk management committee to monitor and manage market risks.

See "— Critical Accounting Policies and Estimates — Accounting for Risk Management and Hedging Activities and Financial Instruments" for further discussion of the accounting for derivative contracts.

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. On August 1, 2007, we entered into interest rate swap agreements, which commenced 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. 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. 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 $305.0 million as of September 28, 2007, a 0.5% movement in the base rate or LIBOR rate would result in an approximately $1.5 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.

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" 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.

Valuation — Valuation of a contract's fair value is validated by an internal group independent of the trading group. While common industry practices are used to develop valuation techniques, changes in pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition. When available, quoted market prices or prices obtained through external sources are used to determine a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected correlations with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

Hedging Strategies — We closely monitor the risks associated with commodity price changes on our future operations and, where appropriate, use various commodity instruments such as natural gas and crude oil contracts to mitigate the effect pricing fluctuations may have on the value of our assets and operations.

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.

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. 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.

The derivative financial instruments we have entered into are typically referred to as “swap” contracts. These swap contracts entitle us to receive payment from the counterparty to the contract to the extent that the reference price is below the swap price stated in the contract, and we are required to make payment to the counterparty to the extent that the reference price is higher than the swap price stated in the contract. The swap contracts we have entered into to mitigate price risk associated with natural gas relate to the price of natural gas, settle on a monthly basis and provide that the reference price for each settlement period are the monthly index price for natural gas delivered into either the Texas Gas Transmission pipeline in the North Louisiana area or the Panhandle Eastern Pipe Line (Texas, Oklahoma – mainline) as published by an independent industry publication. The swap contracts we have entered into to mitigate price risk associated with NGLs and condensate relate to the price of crude oil, settle on a monthly basis and provide that the reference price for each settlement period are the average price for the month in which the Asian-pricing of NYMEX futures contracts for light, sweet crude oil. The notional volume for each period covered, and the time periods covered, by these contracts is set forth in the table below.

The counterparties to each of the swap contracts we have entered into are investment-grade rated financial institutions. Under these contracts, we may be required to provide collateral to the counterparties in the event that our potential payment exposure exceeds a predetermined “collateral threshold.” The assessment of our position with respect to the “collateral thresholds” are determined on a counterparty by counterparty basis and are impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative crude oil and natural gas forward price curves, it is not practical to determine a single pricing point at which our swap contracts will meet the “collateral thresholds.” We have not been required to post collateral with any of our counterparties, and based on internally generated pricing forecasts, do not believe we will meet any of these collateral thresholds in the near term. As the swap contracts settle and the notional volume outstanding decreases, the forward curve price at which point collateral is required would be higher. Predetermined collateral thresholds for hedges guaranteed by DCP Midstream, LLC are generally dependent on DCP Midstream, LLC’s credit rating and would be reduced to $0 in the event DCP Midstream, LLC’s credit rating were to fall below investment grade. DCP Midstream, LLC has provided guarantees to support certain natural gas, NGL and condensate hedging contracts through 2010 that were executed prior to our initial public offering.

The following table sets forth additional information about our natural gas and crude oil swaps used to mitigate our natural gas and NGL price risk associated with our percentage-of-proceeds arrangements and our condensate price risk associated with our gathering operations:

Period	Commodity	Notional Volume	Reference Price	Swap Price
January 2007 — December 2007	Natural Gas	4,100 MMBtu/d	Texas Gas Transmission Price(1)	$ 9.20/MMBtu
January 2008 — December 2008	Natural Gas	4,000 MMBtu/d	Texas Gas Transmission Price(1)	$ 9.20/MMBtu
January 2009 — December 2009	Natural Gas	4,000 MMBtu/d	Texas Gas Transmission Price(1)	$ 9.20/MMBtu
January 2010 — December 2010	Natural Gas	3,900 MMBtu/d	Texas Gas Transmission Price(1)	$ 9.20/MMBtu
June 2007 — December 2013	Natural Gas	1,500 MMBtu/d	NYMEX Final Settlement Price (2)	$ 8.22/MMBtu
June 2007 — December 2013	Natural Gas Basis	1,500 MMBtu/d	IFERC Monthly Index Price for Panhandle Eastern Pipe Line (4)	NYMEX less $ 0.68/MMBtu
January 2007 — December 2007	Crude Oil	660 Bbls/d	Asian-pricing of NYMEX crude oil futures(3)	$ 63.27/Bbl
January 2008 — December 2008	Crude Oil	650 Bbls/d	Asian-pricing of NYMEX crude oil futures(3)	$ 63.27/Bbl
January 2009 — December 2009	Crude Oil	650 Bbls/d	Asian-pricing of NYMEX crude oil futures(3)	$ 63.27/Bbl
January 2010 — December 2010	Crude Oil	640 Bbls/d	Asian-pricing of NYMEX crude oil futures(3)	$ 63.27/Bbl
January 2011 — December 2011	Crude Oil	350 Bbls/d	Asian-pricing of NYMEX crude oil futures(3)	$ 68.50/Bbl
June 2007 — December 2013	Crude Oil	650 Bbls/d	Asian-pricing of NYMEX crude oil futures (3)	$ 67.60/Bbl
January 2011 — December 2011	Crude Oil	250 Bbls/d	Asian-pricing of NYMEX crude oil futures(3)	$ 71.35/Bbl
January 2012 — December 2012	Crude Oil	600 Bbls/d	Asian-pricing of NYMEX crude oil futures(3)	$ 71.00/Bbl

Period	Commodity	Notional Volume	Reference Price	Swap Price
January 2013 — December 2013	Crude Oil	600 Bbls/d	Asian-pricing of NYMEX crude oil futures(3)	$ 71.20/Bbl
July 2007 — December 2007	Crude Oil	1,100 Bbls/d	Asian-pricing of NYMEX crude oil futures(3)	$ 66.72/Bbl
January 2008 — December 2008	Crude Oil	1,000 Bbls/d	Asian-pricing of NYMEX crude oil futures(3)	$ 66.72/Bbl
January 2009 — December 2009	Crude Oil	925 Bbls/d	Asian-pricing of NYMEX crude oil futures(3)	$ 66.72/Bbl
January 2010 — December 2010	Crude Oil	900 Bbls/d	Asian-pricing of NYMEX crude oil futures(3)	$ 66.72/Bbl
January 2011 — December 2011	Crude Oil	875 Bbls/d	Asian-pricing of NYMEX crude oil futures(3)	$ 66.72/Bbl
January 2012 — December 2012	Crude Oil	850 Bbls/d	Asian-pricing of NYMEX crude oil futures(3)	$ 66.72/Bbl

(1) The Inside FERC index price for natural gas delivered into the Texas Gas Transmission pipeline in the North Louisiana area.

(2) NYMEX final settlement price for natural gas futures contracts (NG).

(3) Monthly average of the daily close prices for the prompt month NYMEX light, sweet crude oil futures contract (CL).

(4) The Inside FERC monthly published index price for Panhandle Eastern Pipe Line (Texas, Oklahoma – mainline) less the NYMEX final settlement price for natural gas futures contracts.

At June 30, 2007, the aggregate fair value of the crude oil and natural gas swaps described above was a $20.1 million net loss and a $5.2 million net gain, respectively.

Asset-Based Activities — 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 differentials 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.

Our profitability is affected by changes in prevailing natural gas, propane, NGL and condensate prices. Historically, changes in the prices of most NGL products and condensate have generally correlated with changes in the price of crude oil. Natural gas, propane, NGL and condensate prices are volatile and are impacted by changes in the supply and demand for these commodities, as well as market uncertainty. For a discussion of the volatility of natural gas and NGL prices, please read “Risk Factors — Risks Related to Our Business” in our Annual Report on Form 10-K for the year ended December 31, 2006. The cash flows from our Natural Gas Services and Wholesale Propane Logistics segments are affected by natural gas, NGL and condensate prices, and decreases in these prices could adversely affect our ability to make distributions to holders of our common units and subordinated units. Additionally, since weather conditions may adversely affect the overall demand for propane, our wholesale propane business is vulnerable to, and could be adversely affected by, milder winters.

The fair value of our interest rate and commodity non-trading derivatives is expected to be realized in future periods, as detailed in the following table. The amount of cash ultimately realized for these contracts will differ from the amounts shown in the following table due to factors such as market volatility, counterparty default and other unforeseen events that could impact the amount and/or realization of these values.

Sources of Fair Value	Fair Value of Derivative Contracts as of June 30, 2007				
	Maturity in 2007	Maturity in 2008	Maturity in 2009	Maturity in 2010 and Thereafter	Total Fair Value
	($ in millions)				
Prices supported by quoted market prices and other external sources	$ (0.4)	$ (3.4)	$ (4.4)	$ (6.6)	$ (14.8)
Prices based on models or other valuation techniques	(1.6)	—	1.0	0.2	(0.4)
Total	$ (2.0)	$ (3.4)	$ (3.4)	$ (6.4)	$ (15.2)

The "prices supported by quoted market prices and other external sources" category includes our interest rate swaps, our New York Mercantile Exchange ("NYMEX") swap positions in natural gas and our Asian-pricing NYMEX crude oil swaps. As of June 30, 2007, the NYMEX has quoted monthly natural gas prices for the next 72 months and quoted monthly crude oil prices for the next 66 months. In addition, this category includes our forward positions in natural gas basis swaps at points for which over-the-counter, or OTC, broker quotes are available. On average, OTC quotes as of June 30, 2007, for natural gas swaps extend 21 - 42 months into the future for the market locations at which we transact. Additionally, this category includes our forward positions in propane swaps for which OTC broker quotes are available, on average extend 17 months into the future as of June 30, 2007. These positions are valued against internally developed forward market price curves that are validated and recalibrated against OTC broker quotes. This category also includes "strip" transactions whose prices are obtained from external sources and then modeled to daily or monthly prices as appropriate.

The "prices based on models and other valuation methods" category includes the value of transactions for which an internally developed price curve was constructed as a result of the long dated nature of the transaction or the illiquidity of the market point.

Normal Purchases and Normal Sales — If a contract qualifies and is designated as a normal purchase or normal sale, no recognition of the contract's fair value in the consolidated financial statements is required until the associated delivery period impacts earnings. We have applied this accounting election for contracts involving the purchase or sale of physical natural gas, propane or NGLs in future periods.

Exhibit 99.3

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
DCP Midstream Partners GP, LLC
Denver, Colorado:

We have audited the accompanying consolidated balance sheets of DCP Midstream Partners, LP and subsidiaries (the “Company”) as of December 31, 2006 and 2005, and the related consolidated statements of operations, comprehensive income, changes in partners’ equity, and cash flows for each of the three years in the period ended December 31, 2006. Our audits also included the financial statement schedule. These financial statements and financial statement schedule are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. The consolidated financial statements give retroactive effect to the acquisition of a 25% limited liability interest in DCP East Texas Holdings, LLC (“East Texas”), a 40% limited liability interest in Discovery Producer Services LLC (“Discovery”), and a nontrading derivative instrument (the “Swap”) from DCP Midstream, LLC (“Midstream”) by the Company on July 1, 2007, which has been accounted for in a manner similar to a pooling of interests as described in Note 4 to the consolidated financial statements. We did not audit the financial statements of Discovery, an investment of the Company which is accounted for by the use of the equity method. The Company’s equity in Discovery’s net assets of $162,040,000 and $155,298,000 at December 31, 2006 and 2005, respectively, and in Discovery’s net income of $12,033,000, $6,909,000, and $3,890,000 for the years ended December 31, 2006, 2005 and 2004, respectively, are included in the accompanying consolidated financial statements. Discovery’s financial statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to amounts included for Discovery, is based solely on the report of such other auditors.

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

In our opinion, based on our audits and the report of the other auditors, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, after giving retroactive effect to the acquisition of East Texas, Discovery, and the Swap as described in Note 4 to the consolidated financial statements, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule when considered with the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company was formed on December 7, 2005 and began operating as a separate entity. Through December 7, 2005 the accompanying consolidated financial statements have been prepared from the separate records maintained by Midstream and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unaffiliated entity. Portions of certain expenses represent allocations made from, and are applicable to, Midstream as a whole.

The consolidated financial statements also give retroactive effect to the November 1, 2006 acquisition by the Company of the wholesale propane logistics business which, as a combination of entities under common control, has been accounted for similar to a pooling of interests as described in Note 4 to the consolidated financial statements. Also as described in Note 1 to the consolidated financial statements, through November 1, 2006, the portion of the accompanying consolidated financial statements attributable to the wholesale propane logistics business, have been prepared from the separate records maintained by Midstream and may not necessarily be indicative of the conditions that would have existed or the results of operations if the wholesale propane logistics business had been operated as an unaffiliated entity. Portions of certain expenses represent allocations made from, and are applicable to Midstream as a whole.

Also as described in Note 1 to the consolidated financial statements, the portion of the accompanying consolidated financial statements attributable to East Texas, Discovery and the Swap have been prepared from the separate records maintained by Midstream and may not necessarily be indicative of the conditions that would have existed or the results of operations if East Texas, Discovery and the Swap had been operated as unaffiliated entities. Portions of certain expenses represent allocations made from, and are applicable to Midstream as a whole.

/s/ Deloitte & Touche LLP

Denver, Colorado
October 16, 2007

Report of Independent Registered Public Accounting Firm

To the Management Committee of
Discovery Producer Services LLC

We have audited the accompanying consolidated balance sheets of Discovery Producer Services LLC as of December 31, 2006 and 2005, and the related consolidated statements of income, members' capital, and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

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

/s/ Ernst & Young LLP

Tulsa, Oklahoma
March 5, 2007

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

	June 30, 2007 (unaudited)	December 31, 2006	December 31, 2005
		($ in millions)	
ASSETS			
Current assets:			
Cash and cash equivalents	$ 55.0	$ 46.2	$ 42.2
Short-term investments	—	0.6	—
Accounts receivable:			
Trade, net of allowance for doubtful accounts of $0.6 million (unaudited), $0.3 million and $0.3 million, respectively	40.2	43.4	65.7
Affiliates	30.4	34.8	56.5
Inventories	30.3	30.1	41.7
Unrealized gains on non-trading derivative and hedging instruments	3.2	4.2	0.2
Other	0.2	0.3	0.1
Total current assets	159.3	159.6	206.4
Restricted investments	—	102.0	100.4
Property, plant and equipment, net	370.7	194.7	178.7
Goodwill	29.3	29.3	29.3
Intangible assets, net	15.0	2.8	3.2
Equity method investments	168.4	170.2	155.7
Unrealized gains on non-trading derivative and hedging instruments	5.0	6.5	5.4
Other non-current assets	1.3	0.8	1.0
Total assets	$ 749.0	$ 665.9	$ 680.1
LIABILITIES AND PARTNERS' EQUITY			
Current liabilities:			
Accounts payable:			
Trade	$ 70.7	$ 66.9	$ 95.9
Affiliates	21.6	50.4	42.4
Unrealized losses on non-trading derivative and hedging instruments	6.8	0.7	2.7
Accrued interest payable	0.4	1.1	0.8
Other	7.3	7.4	4.5
Total current liabilities	106.8	126.5	146.3
Long-term debt	249.0	268.0	210.1
Unrealized losses on non-trading derivative and hedging instruments	16.6	2.7	2.5
Other long-term liabilities	2.3	1.0	0.5
Total liabilities	374.7	398.2	359.4
Commitments and contingent liabilities			
Partners' equity:			
Predecessor equity	153.3	164.3	219.8
Common unitholders (13,362,923, 10,357,143 and 10,357,143 units issued and outstanding, respectively)	349.9	223.4	215.8
Class C unitholders (200,312, 200,312 and 0 units issued and outstanding, respectively)	(20.7)	(20.7)	—
Subordinated unitholders (7,142,857 convertible units issued and outstanding at all periods)	(102.5)	(101.6)	(109.7)
General partner interest	(5.0)	(5.0)	(5.6)
Accumulated other comprehensive income	(0.5)	7.3	0.4
Total	374.5	267.7	320.7
Less treasury units, at cost (4,000, 0 and 0, respectively)	(0.2)	—	—
Total partners' equity	374.3	267.7	320.7
Total liabilities and partners' equity	$ 749.0	$ 665.9	$ 680.1

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006	Year Ended December 31, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
	(unaudited)				
	($ in millions, except per unit amounts)				
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$301.9	$291.6	$535.1	$1,004.6	$729.8
Sales of natural gas, propane, NGLs and condensate to affiliates	116.6	121.0	232.8	117.5	85.6
Transportation and processing services	6.9	7.4	15.0	12.5	9.5
Transportation and processing services to affiliates	7.9	6.0	12.8	10.6	11.0
Losses from non-trading derivative activity, net	(14.5)	—	—	—	—
(Losses) gains from non-trading derivative activity — affiliates	(0.5)	(0.5)	0.1	(0.9)	(1.9)
Total operating revenues	418.3	425.5	795.8	1,144.3	834.0
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	292.6	324.3	581.2	889.5	644.2
Purchases of natural gas, propane and NGLs from affiliates	83.5	55.6	119.2	157.8	116.4
Operating and maintenance expense	12.9	11.5	23.7	22.4	19.8
Depreciation and amortization expense	7.9	6.4	12.8	12.7	14.7
General and administrative expense	7.0	5.5	12.9	5.1	0.9
General and administrative expense — affiliates	4.7	3.8	8.1	9.1	7.8
Total operating costs and expenses	408.6	407.1	757.9	1,096.6	803.8
Operating income	9.7	18.4	37.9	47.7	30.2
Interest income	2.5	3.0	6.3	0.5	—
Interest expense	(8.4)	(5.2)	(11.5)	(0.8)	—
Earnings from equity method investments	12.8	15.8	29.2	25.7	17.6
Impairment of equity method investment	—	—	—	—	(4.4)
Income before income taxes	16.6	32.0	61.9	73.1	43.4
Income tax expense	—	—	—	3.3	2.5
Net income	$ 16.6	$ 32.0	$ 61.9	$ 69.8	$ 40.9
Less:					
Net income attributable to predecessor operations	(3.6)	(17.8)	(26.6)	(65.1)	(40.9)
General partner interest in net income	(0.6)	(0.3)	(0.7)	(0.1)	—
Net income allocable to limited partners	$ 12.4	$ 13.9	$ 34.6	$ 4.6	$ —
Net income per limited partner unit — basic and diluted	$ 0.60	$ 0.79	$ 1.90	$ 0.20	$ —
Weighted-average limited partner units outstanding — basic and diluted	17.8	17.5	17.5	17.5	—

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Six Months Ended June 30,		Year Ended December 31,		
	2007	2006	2006	2005	2004
	(unaudited)				
	($ in millions)				
Net income	$ 16.6	$ 32.0	$ 61.9	$ 69.8	$ 40.9
Other comprehensive income:					
Reclassification of cash flow hedges into earnings	(2.1)	(0.7)	(2.7)	—	—
Net unrealized (losses) gains on cash flow hedges	(5.7)	(2.8)	9.6	0.4	—
Total other comprehensive income	(7.8)	(3.5)	6.9	0.4	—
Total comprehensive income	$ 8.8	$ 28.5	$ 68.8	$ 70.2	$ 40.9

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' EQUITY

	Predecessor Equity	Treasury Units	Common Unitholders	Class C Unitholders	Subordinated Unitholders	General Partner Interest	Accumulated Other Comprehensive Income	Total Partners' Equity
				($ in millions)				
Balance, January 1, 2004	$ 395.1	$ —	$ —	$ —	$ —	$ —	$ —	$ 395.1
Net change in parent advances	(35.5)	—	—	—	—	—	—	(35.5)
Net income attributable to predecessor operations	40.9	—	—	—	—	—	—	40.9
Balance, December 31, 2004	400.5	—	—	—	—	—	—	400.5
Net change in parent advances	(137.7)	—	—	—	—	—	—	(137.7)
Proceeds from initial public offering of 10,350,000 common units	—	—	222.5	—	—	—	—	222.5
Underwriters' discount and offering expenses	—	—	(9.3)	—	(6.4)	(0.4)	—	(16.1)
Distribution to unitholders	(218.7)	—	—	—	—	—	—	(218.7)
Allocation of predecessor equity in exchange for 7,143 common units, 7,142,857 subordinated units and a 2% general partnership interest (represented by 357,143 equivalent units)	110.6	—	(0.1)	—	(105.2)	(5.3)	—	—
Net income attributable to predecessor operations	65.1	—	—	—	—	—	—	65.1
Net income from December 7, 2005 through December 31, 2005	—	—	2.7	—	1.9	0.1	—	4.7
Other comprehensive income	—	—	—	—	—	—	0.4	0.4
Balance, December 31, 2005	219.8	—	215.8	—	(109.7)	(5.6)	0.4	320.7
Net change in parent advances	(25.4)	—	—	—	—	—	—	(25.4)
Acquisition of wholesale propane logistics business	(56.7)	—	—	—	—	—	—	(56.7)
Excess purchase price over acquired assets	—	—	—	(26.3)	—	—	—	(26.3)
Issuance of 200,312 Class C units	—	—	—	5.6	—	—	—	5.6
Proceeds from general partner interest (represented by 4,088 equivalent units)	—	—	—	—	—	0.1	—	0.1
Contributions by unitholders	—	—	—	—	2.8	0.2	—	3.0
Distributions to unitholders	—	—	(12.8)	(0.1)	(8.8)	(0.4)	—	(22.1)
Net income attributable to predecessor operations	26.6	—	—	—	—	—	—	26.6
Net income	—	—	20.4	0.1	14.1	0.7	—	35.3
Other comprehensive income	—	—	—	—	—	—	6.9	6.9
Balance, December 31, 2006	164.3	—	223.4	(20.7)	(101.6)	(5.0)	7.3	267.7
Net change in parent advances	(14.6)	—	—	—	—	—	—	(14.6)
Purchase of treasury units	—	(0.2)	—	—	—	—	—	(0.2)
Issuance of common units	—	—	128.5	—	—	—	—	128.5
Contributions by unitholders	—	—	—	—	0.4	—	—	0.4
Distributions to unitholders	—	—	(9.2)	(0.2)	(6.4)	(0.6)	—	(16.4)
Equity-based compensation	—	—	0.1	—	—	—	—	0.1
Net income attributable to predecessor operations	3.6	—	—	—	—	—	—	3.6
Net income	—	—	7.1	0.2	5.1	0.6	—	13.0
Other comprehensive income	—	—	—	—	—	—	(7.8)	(7.8)
Balance, June 30, 2007 (unaudited)	$ 153.3	$ (0.2)	$ 349.9	$ (20.7)	$ (102.5)	$ (5.0)	$ (0.5)	$ 374.3

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006	Year Ended December 31, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
	(unaudited)		($ in millions)		
OPERATING ACTIVITIES:					
Net income	$ 16.6	$ 32.0	$ 61.9	$ 69.8	$ 40.9
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization expense and impairment charge	7.9	6.4	12.8	12.7	19.1
Earnings from equity method investments, net of distributions	5.7	(4.7)	(3.3)	11.0	(4.2)
Deferred income tax benefit	—	—	—	(0.5)	(0.1)
Other, net	(0.4)	(1.4)	(2.4)	0.1	(0.2)
Change in operating assets and liabilities which provided (used) cash:					
Accounts receivable	9.8	73.9	43.1	(30.7)	(19.0)
Inventories	(0.2)	12.4	11.6	(21.0)	0.2
Net unrealized losses (gains) on non-trading derivative and hedging instruments	14.9	0.9	(0.1)	0.1	0.3
Accounts payable	(14.2)	(83.0)	(31.5)	74.7	0.8
Accrued interest	(0.7)	(0.2)	0.3	0.8	—
Income tax payable	—	—	—	(3.2)	(0.1)
Other current assets and liabilities	(0.2)	1.7	2.0	(0.7)	0.4
Other non-current assets and liabilities	0.6	—	0.4	(0.1)	—
Net cash provided by operating activities	39.8	38.0	94.8	113.0	38.1
INVESTING ACTIVITIES:					
Capital expenditures	(7.6)	(12.1)	(27.2)	(10.8)	(3.3)
Acquisition of assets	(191.3)	—	—	—	—
Acquisition of wholesale propane logistics business	—	—	(56.7)	—	—
Investments in equity method investees	(3.9)	(7.4)	(11.1)	(20.5)	—
Payment of earnest deposit	(9.0)	—	—	—	—
Refund of earnest deposit	9.0	—	—	—	—
Proceeds from sales of assets	0.1	0.1	0.3	1.2	0.7
Purchases of available-for-sale securities	(6,427.7)	(4,249.8)	(7,372.4)	(731.0)	—
Proceeds from sales of available-for-sale securities	6,531.1	4,248.8	7,373.3	630.8	—
Other investing activities	—	—	—	(0.1)	—
Net cash used in investing activities	(99.3)	(20.4)	(93.8)	(130.4)	(2.6)
FINANCING ACTIVITIES:					
Borrowings under debt facilities	188.0	—	78.0	210.1	—
Repayments of debt	(207.0)	(20.1)	(20.1)	—	—
Payment of deferred financing costs	(0.5)	—	(0.2)	(0.5)	—
Proceeds from issuance of common units, net of offering costs	128.5	—	—	206.4	—
Proceeds from issuance of equivalent units to general partner	—	—	0.1	—	—
Purchase of treasury units	(0.2)	—	—	—	—
Excess purchase price over acquired assets	(9.9)	—	(10.7)	—	—
Net change in advances from DCP Midstream, LLC	(14.6)	(14.6)	(25.4)	(137.7)	(35.5)
Distributions to unitholders	(16.4)	(8.0)	(22.1)	(218.7)	—
Contributions from unitholders	0.4	3.2	3.4	—	—
Net cash provided by (used in) financing activities	68.3	(39.5)	3.0	59.6	(35.5)
Net change in cash and cash equivalents	8.8	(21.9)	4.0	42.2	—
Cash and cash equivalents, beginning of period	46.2	42.2	42.2	—	—
Cash and cash equivalents, end of period	$ 55.0	$ 20.3	$ 46.2	$ 42.2	$ —
Supplementary disclosure of cash flow information:					
Cash paid for interest expense, net of capitalized interest	$ 10.0	$ 5.4	$ 11.1	$ —	$ —
Cash paid for income taxes	$ —	$ —	$ —	$ 2.6	$ 2.7

See accompanying notes to consolidated financial statements.

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. DCP Midstream, LLC directs our business operations through its ownership and control of the General Partner. DCP Midstream, LLC and its affiliates' employees provide administrative support to us and operate or manage the operation of our assets. DCP Midstream, LLC owns in aggregate an approximate 35% interest in our partnership.

The consolidated financial statements include our accounts, and prior to December 7, 2005 the assets, liabilities and operations contributed to us by DCP Midstream, LLC and its wholly-owned subsidiaries, which we refer to as DCP Midstream Partners Predecessor, upon the closing of our initial public offering.

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 all periods presented.

In July 2007, we acquired our 25% limited liability company interest in DCP East Texas Holdings, LLC, or East Texas, our 40% limited liability company interest in Discovery Producer Services LLC, or Discovery, and our non-trading derivative instrument, or the Swap, which DCP Midstream, LLC entered into in March 2007, from DCP Midstream, LLC in a transaction among entities under common control. Accordingly, these consolidated financial statements include the historical results of the equity interest in East Texas and Discovery, and the historical results of the Swap, for all periods presented.

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. We refer to DCP Midstream Partners Predecessor, the assets, liabilities and operations of our wholesale propane logistics business prior to our acquisition from DCP Midstream, LLC in November 2006, our equity interests in East Texas and Discovery, and the Swap, collectively as our "predecessors." The consolidated financial statements of our predecessors 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 predecessors 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 consolidated financial statements as transactions between affiliates. The accompanying unaudited consolidated financial statements have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission, or SEC. Accordingly these 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.

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 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.

Reclassifications — Certain prior period amounts have been reclassified in the consolidated financial statements to conform to the current period presentation.

Cash and Cash Equivalents — We consider investments in highly liquid financial instruments purchased with an original stated maturity of 90 days or less to be cash equivalents.

Short-Term and Restricted Investments — Short-term investments consist of $0.6 million at December 31, 2006. We had no short-term investments at June 30, 2007 (unaudited) or December 31, 2005. We invest available cash balances in various financial instruments, such as tax-exempt debt securities, that have stated maturities of 20 years or more. These instruments provide for a high degree of liquidity through features, which allow for the redemption of the investment at its face amount plus earned income. As we generally intend to sell these instruments within one year or less from the balance sheet date, and as they are available for use in current operations, they are classified as current assets, unless otherwise restricted.

Restricted investments consist of $102.0 million and $100.4 million in investments in commercial paper and various other high-grade debt securities at December 31, 2006 and 2005, respectively. These investments are 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 unaudited.

We have classified all short-term and restricted investments as available-for-sale as we do not intend to hold them to maturity, nor are they bought or sold with the objective of generating profit on short-term differences in prices. These investments are recorded at fair value, with changes in fair value recorded as unrealized gains and losses in accumulated other comprehensive income, or AOCI. No gains or losses were deferred in AOCI at June 30, 2007 (unaudited), December 31, 2006 or 2005. The cost, including accrued interest on investments, approximates fair value, due to the short-term, highly liquid nature of the securities held by us, and as interest rates are re-set on a daily, weekly or monthly basis.

Gas and NGL Imbalance Accounting — Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements with customers, producers or pipelines are recorded monthly as other receivables or other payables using current market prices or the weighted-average prices of natural gas or NGLs at the plant or system. These balances are settled with deliveries of natural gas or NGLs, or with cash.

Included in the consolidated balance sheets as accounts receivable—trade, were imbalances of $0.2 million (unaudited), $0.1 million and $1.1 million at June 30, 2007, December 31, 2006 and 2005, respectively. Included in the consolidated balance sheets as accounts payable—trade, were imbalances of $1.3 million (unaudited), $0.9 million and $2.5 million at June 30, 2007, December 31, 2006 and 2005, respectively.

Inventories — Inventories consist primarily of propane. Inventories are recorded at the lower of weighted-average cost or market value. Transportation costs are included in inventory on the consolidated balance sheets.

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

Asset retirement obligations associated with tangible long-lived assets are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made, and added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability increases due to the passage of time based on the time value of money until the obligation is settled. We recognize a liability of a conditional asset retirement obligation as soon as the fair value of the liability can be reasonably estimated. A conditional asset retirement obligation is defined as an unconditional legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity.

Goodwill and Intangible Assets — Goodwill is the cost of an acquisition less the fair value of the net assets of the acquired business. The goodwill on the consolidated balance sheets was recognized by DCP Midstream, LLC when it acquired certain assets which are now included in the wholesale propane logistics business, and was allocated based on fair value to the wholesale propane logistics business in order to present historical information about the assets we acquired. We evaluate goodwill for impairment annually in the third quarter, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Impairment testing of goodwill consists of a two-step process. The first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of the reporting unit exceeds its fair value, the second step of the process involves comparing the fair value and carrying value of the goodwill of that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the fair value of that goodwill, an impairment loss is recognized in an amount equal to the excess.

Intangible assets consist primarily of commodity contracts. The commodity contracts are amortized on a straight-line basis over the period of expected future benefit, ranging from approximately five to 25 years.

Equity Method Investments — We account for investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence, under the equity method.

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

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

- significant adverse change in legal factors or business climate;
- a current-period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- significant adverse changes in the extent or manner in which an asset is used, or in its physical condition;
- a significant adverse change in the market value of an asset; or
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

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

Unamortized Debt Expense — Expenses incurred with the issuance of long-term debt are amortized over the terms of the debt using the effective interest method. These expenses are recorded on the consolidated balance sheet as other non-current assets.

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 (unaudited) 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

Each derivative not qualifying as a normal purchase or normal sales is recorded on a gross basis in the consolidated balance sheets at its fair value as unrealized gains or unrealized losses on non-trading derivative and hedging instruments. Derivative assets and liabilities remain classified in our consolidated balance sheets as unrealized gains or unrealized losses on non-trading derivative and hedging instruments at fair value until the contractual settlement period impacts earnings.

All derivative activity reflected in the consolidated financial statements for our predecessors was transacted by us or by DCP Midstream, LLC and its subsidiaries, and transferred and/or allocated to us. All derivative activity reflected in the consolidated financial statements, which is not related to our predecessors, has been and will be transacted by us, although DCP Midstream, LLC personnel execute various transactions on our behalf. We designate each energy commodity derivative as either trading or non-trading. Certain non-trading derivatives are further designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or normal purchases or normal sales, while certain non-trading derivatives, which are related to asset-based activities, are designated as non-trading derivative activity. For the periods presented, we did not have any trading derivative activity, however, we do have cash flow and fair value hedge activity, normal purchases and normal sales activity, and non-trading derivative activity included in the consolidated financial statements. For each derivative, the accounting method and presentation of gains and losses or revenue and expense in the consolidated statements of operations are as follows:

Classification of Contract	Accounting Method	Presentation of Gains & Losses or Revenue & Expense
Non-Trading Derivative Activity	Mark-to-market method (a)	Net basis in (losses) gains from non-trading derivative activity
Cash Flow Hedge	Hedge method (b)	Gross basis in the same consolidated statements of operations category as the related hedged item
Fair Value Hedge	Hedge method (b)	Gross basis in the same consolidated statements of operations category as the related hedged item
Normal Purchases or Normal Sales	Accrual method (c)	Gross basis upon settlement in the corresponding consolidated statements of operations category based on purchase or sale

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

(b) Hedge method — An accounting method whereby the change in the fair value of the asset or liability is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on non-trading derivative and hedging instruments. For cash flow hedges, there is no recognition in the consolidated statements of operations for the effective portion until the service is provided or the associated delivery period impacts earnings. For fair value hedges, the change in the fair value of the asset or liability, as well as the offsetting changes in value of the hedged item, are recognized in the consolidated statements of operations in the same category as the related hedged item.

(c) Accrual method — An accounting method whereby there is no recognition in the consolidated balance sheets or consolidated statements of operations for changes in fair value of a contract until the service is provided or the associated delivery period impacts earnings.

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

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

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

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

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

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 recognize revenues for sales and services under the four revenue recognition criteria, as follows:

- *Persuasive evidence of an arrangement exists* — Our customary practice is to enter into a written contract, executed by both us and the customer.
- *Delivery* — Delivery is deemed to have occurred at the time custody is transferred, or in the case of fee-based arrangements, when the services are rendered. To the extent we retain product as inventory, delivery occurs when the inventory is subsequently sold and custody is transferred to the third party purchaser.
- *The fee is fixed or determinable* — We negotiate the fee for our services at the outset of our fee-based arrangements. In these arrangements, the fees are nonrefundable. For other arrangements, the amount of revenue, based on contractual terms, is determinable when the sale of the applicable product has been completed upon delivery and transfer of custody.
- *Collectability is probable* — Collectability is evaluated on a customer-by-customer basis. New and existing customers are subject to a credit review process, which evaluates the customers' financial position (for example, cash position and credit rating) and their ability to pay. If collectability is not considered probable at the outset of an arrangement in accordance with our credit review process, revenue is recognized when the fee is collected.

We generally report revenues gross in the 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. We recognize revenues from non-trading derivative activity net in the consolidated statements of operations as (losses) gains from non-trading derivative activity. These activities include mark-to-market gains and losses on energy trading contracts and the financial or physical settlement of energy trading contracts.

Significant Customer — We had one customer, a third party, that accounted for 17% and 18% of total operating revenues for the years ended December 31, 2005 and 2004, respectively. Revenues from this customer are reported in the NGL Logistics Segment. There were no customers that accounted for more than 10% of total operating revenues for the six months ended June 30, 2007 (unaudited) or for the year ended December 31, 2006. We also had significant transactions with affiliates, and with suppliers of propane (see "Management's Discussion and Analysis of Financial Condition and Results of Operations").

Environmental Expenditures — Environmental expenditures are expensed or capitalized as appropriate, depending upon the future economic benefit. Expenditures that relate to an existing condition caused by past operations and that do not generate current or future revenue are expensed. Liabilities for these expenditures are recorded on an undiscounted basis when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. Environmental liabilities as of June 30, 2007 (unaudited), December 31, 2006 and 2005, included in the consolidated balance sheets as other current liabilities, were not significant.

Equity-Based Compensation — Under the DCP Midstream Partners, LP Long-Term Incentive Plan, or the LTIP, equity instruments may be granted to our key employees. The General Partner adopted the LTIP for employees, consultants and directors of the General Partner and its affiliates who perform services for us. The LTIP provides for the grant of restricted units, 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 common units may be delivered pursuant to awards under the LTIP. Awards that are cancelled, forfeited or are 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. Awards were first granted under the LTIP during 2006.

Equity classified stock-based compensation cost is measured at grant date, based on the estimated fair value of the award, and is recognized as expense over the vesting period. Liability classified stock-based compensation cost is remeasured at each reporting date and is recognized as expense over the requisite service period. Compensation expense for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award. Awards granted to non-employees for acquiring, or in conjunction with selling, goods and services, are measured at the estimated fair value of the goods or services, or the fair value of the award, whichever is more reliably measured.

Income Taxes — We are structured as a master limited partnership which is a pass-through entity for federal income tax purposes. Our wholesale propane logistics business changed its tax structure, effective December 7, 2005, such that it became a pass-through entity. Prior to December 7, 2005, our wholesale propane logistics business was considered taxable for United States income tax purposes. Our wholesale propane logistics business followed the asset and liability method of accounting for income taxes, whereby deferred income taxes are recognized for the tax consequences of temporary differences between the financial statement carrying amounts and the tax basis of the assets and liabilities. Subsequent to December 7, 2005, our taxable income or loss, which may vary substantially from the net income or loss reported in the consolidated statements of operations, is includable in the federal returns of each partner.

Comprehensive Income — Comprehensive income consists of net income and other comprehensive income, which includes unrealized gains and losses on the effective portion of derivative instruments classified as cash flow hedges.

Net Income per Limited Partner Unit — Basic and diluted net income per limited partner unit is calculated by dividing limited partners' interest in net income, less pro forma general partner incentive distributions by the weighted-average number of outstanding limited partner units during the period.

3. New Accounting Standards

***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.

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

***FASB Interpretation Number, or FIN, 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. The adoption of FIN 48 did not have a material impact on our consolidated results of operations, cash flows or financial position.

***EITF Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty*, or EITF 04-13** — In September 2005, the FASB ratified the EITF's consensus on Issue 04-13, which requires an entity to treat sales and purchases of inventory between the entity and the same counterparty as one transaction for purposes of applying APB Opinion No. 29, *Accounting for Nonmonetary Transactions*, or APB 29, when such transactions are entered into in contemplation of each other. When such transactions are legally contingent on each other, they are considered to have been entered into in contemplation of each other. The EITF also agreed on other factors that should be considered in determining whether transactions have been entered into in contemplation of each other. EITF 04-13 was applied to new arrangements that we entered into after March 31, 2006. The adoption of EITF 04-13 did not have a material impact on our consolidated results of operations, cash flows or financial position.

***Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements,* or SAB 108 —** In September 2006, the Securities and Exchange Commission, or SEC, issued SAB 108 to address diversity in practice in quantifying financial statement misstatements. SAB 108 requires entities to quantify misstatements based on their impact on each of their financial statements and related disclosures. SAB 108 is effective as of the end of our 2006 fiscal year, allowing a one-time transitional cumulative effect adjustment to retained earnings as of January 1, 2006 for errors that were not previously deemed material, but are material under the guidance in SAB 108. The adoption of SAB 108 did not have a material impact on our consolidated results of operations, cash flows or financial position.

4. Acquisitions

Gathering and Compression Assets

On July 1, 2007, we acquired a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery and the Swap from DCP Midstream, LLC for aggregate consideration of approximately $271.3 million, consisting of approximately $243.7 million in cash, including net working capital of $1.3 million and other adjustments, 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 of $245.9 million under our amended credit facility. 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 $118.0 million excess purchase price over the historical basis of the net aquired assets will be recorded as a reduction to partners' equity, and the $27.6 million of common and general partner equivalent units issued as partial consideration for this transaction will be recorded as an increase to partners' equity, for financial accounting purposes.

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 closed in the third quarter of 2007. The purchase price consisted of approximately $153.8 million of cash and the issuance of 275,735 common units to an affiliate of DCP Midstream, LLC that were valued at approximately $12.0 million. We have incurred post-closing purchase price adjustments to date that include a liability of $9.0 million for net working capital and general and administrative charges. We financed this transaction with $120.0 million of borrowings under our amended credit facility, the issuance of common units and cash on hand. On May 21, 2007, in connection with this acquisition, DCP Partners 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, DCP Partners has a registration rights agreement to file a shelf registration statement with the SEC to register the units within 90 days of the close of the private placement. In, addition the registration rights agreement requires DCP Partners to use its commercially reasonable efforts to cause the registration statement to become effective within 180 days of the closing of the private placement. If the registration statement covering the common units is not declared effective by the SEC within 180 days of the closing of the private placement, then DCP Partners will be liable to the purchasers for liquidated damages of 0.25% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period for the first 60 days following the 180th day, increasing by an additional 0.25% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period for each subsequent 60 days, up to a maximum of 1.00% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period.

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 (unaudited).

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

The results of operations for these acquired assets have been, or will be, 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 consisting 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 associated with the construction of a new propane 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 $26.3 million excess purchase price over the historical basis of the net acquired assets was recorded as a reduction to partners' equity, and the $5.6 million of Class C units issued as partial consideration for this transaction were recorded as an increase to partners' equity, for financial accounting purposes.

Results

The following tables present the impact on the consolidated balance sheets, adjusted for the acquisition of our wholesale propane logistics business, and for the acquisition of East Texas, Discovery and the Swap, from DCP Midstream, LLC ($ in millions):

As of June 30, 2007 (unaudited)

	DCP Midstream Partners, LP	East Texas, Discovery and the Swap	Combined DCP Midstream Partners, LP
ASSETS			
Current assets:			
Cash and cash equivalents	$ 55.0	$ —	$ 55.0
Accounts receivable	70.6	—	70.6
Inventories	30.3	—	30.3
Other	3.4	—	3.4
Total current assets	159.3	—	159.3
Restricted investments	—	—	—
Property, plant and equipment, net	370.7	—	370.7
Goodwill and intangible assets, net	44.3	—	44.3
Other non-current assets	12.7	162.0	174.7
Total assets	$ 587.0	$ 162.0	$ 749.0
LIABILITIES AND PARTNERS' EQUITY			
Accounts payable and other current liabilities	$ 104.4	$ 2.4	$ 106.8
Long-term debt	249.0	—	249.0
Other long-term liabilities	12.6	6.3	18.9
Total liabilities	366.0	8.7	374.7
Commitments and contingent liabilities			
Partners' equity:			
Net equity	221.5	153.3	374.8
Accumulated other comprehensive loss	(0.5)	—	(0.5)
Total partners' equity	221.0	153.3	374.3
Total liabilities and partners' equity	$ 587.0	$ 162.0	$ 749.0

As of December 31, 2006

	DCP Midstream Partners, LP	East Texas and Discovery	Combined DCP Midstream Partners, LP
ASSETS			
Current assets:			
Cash and cash equivalents	$ 46.2	$ —	$ 46.2
Accounts receivable	78.2	—	78.2
Inventories	30.1	—	30.1
Other	5.1	—	5.1
Total current assets	159.6	—	159.6
Restricted investments	102.0	—	102.0
Property, plant and equipment, net	194.7	—	194.7
Goodwill and intangible assets, net	32.1	—	32.1
Other non-current assets	13.2	164.3	177.5
Total assets	$ 501.6	$ 164.3	$ 665.9
LIABILITIES AND PARTNERS' EQUITY			
Accounts payable and other current liabilities	$ 126.5	$ —	$ 126.5
Long-term debt	268.0	—	268.0
Other long-term liabilities	3.7	—	3.7
Total liabilities	398.2	—	398.2
Commitments and contingent liabilities			
Partners' equity:			
Net equity	96.1	164.3	260.4
Accumulated other comprehensive income	7.3	—	7.3
Total partners' equity	103.4	164.3	267.7
Total liabilities and partners' equity	$ 501.6	$ 164.3	$ 665.9

As of December 31, 2005

	DCP Midstream Partners, LP	Wholesale Propane Logistics Business	East Texas and Discovery	Combined DCP Midstream Partners, LP
ASSETS				
Current assets:				
Cash and cash equivalents	$ 42.2	$ —	$ —	$ 42.2
Accounts receivable	82.0	40.2	—	122.2
Inventories	0.1	41.6	—	41.7
Other	0.2	0.1	—	0.3
Total current assets	124.5	81.9	—	206.4
Restricted investments	100.4	—	—	100.4
Property, plant and equipment, net	168.9	9.8	—	178.7
Goodwill and intangible assets, net	2.1	30.4	—	32.5
Other non-current assets	11.4	0.5	150.2	162.1
Total assets	$ 407.3	$ 122.6	$ 150.2	$ 680.1
LIABILITIES AND PARTNERS' EQUITY				
Accounts payable and other current liabilities	$ 93.4	$ 52.9	$ —	$ 146.3
Long-term debt	210.1	—	—	210.1
Other long-term liabilities	2.9	0.1	—	3.0
Total liabilities	306.4	53.0	—	359.4
Commitments and contingent liabilities				
Partners' equity:				
Net equity	100.5	69.6	150.2	320.3
Accumulated other comprehensive income	0.4	—	—	0.4
Total partners' equity	100.9	69.6	150.2	320.7
Total liabilities and partners' equity	$ 407.3	$ 122.6	$ 150.2	$ 680.1

The following tables present the impact on the consolidated statements of operations, adjusted for the acquisition of our wholesale propane logistics business, and for the acquisition of East Texas, Discovery and the Swap, from DCP Midstream, LLC, for the periods presented ($ in millions):

Six Months Ended June 30, 2007 (unaudited)

	DCP Midstream Partners, LP	East Texas, Discovery and the Swap	Combined DCP Midstream Partners, LP
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 418.5	$ —	$ 418.5
Transportation and other	8.5	(8.7)	(0.2)
Total operating revenues	427.0	(8.7)	418.3
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	376.1	—	376.1
Operating and maintenance expense	12.9	—	12.9
Depreciation and amortization expense	7.9	—	7.9
General and administrative expense	11.7	—	11.7
Total operating costs and expenses	408.6	—	408.6
Operating income	18.4	(8.7)	9.7
Interest expense, net	(5.9)	—	(5.9)
Earnings from equity method investments	0.5	12.3	12.8
Net income	$ 13.0	$ 3.6	$ 16.6

Six Months Ended June 30, 2006 (unaudited)

	DCP Midstream Partners, LP	Wholesale Propane Logistics Business	East Texas and Discovery	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	—	15.7	15.8
Net income	$ 14.2	$ 2.1	$ 15.7	$ 32.0

Year Ended December 31, 2006

	DCP Midstream Partners, LP and Predecessor	East Texas and Discovery	Combined DCP Midstream Partners, LP
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 767.9	$ —	$ 767.9
Transportation and other	27.9	—	27.9
Total operating revenues	795.8	—	795.8
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	700.4	—	700.4
Operating and maintenance expense	23.7	—	23.7
Depreciation and amortization expense	12.8	—	12.8
General and administrative expense	21.0	—	21.0
Total operating costs and expenses	757.9	—	757.9
Operating income	37.9	—	37.9
Interest expense, net	(5.2)	—	(5.2)
Earnings from equity method investments	0.3	28.9	29.2
Income tax expense	—	—	—
Net income	$ 33.0	$ 28.9	$ 61.9

Year Ended December 31, 2005

	DCP Midstream Partners, LP and Predecessor	Wholesale Propane Logistics Business	East Texas and Discovery	Combined DCP Midstream Partners, LP
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 762.3	$ 359.8	$ —	$ 1,122.1
Transportation and other	22.2	—	—	22.2
Total operating revenues	784.5	359.8	—	1,144.3
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	709.3	338.0	—	1,047.3
Operating and maintenance expense	14.2	8.2	—	22.4
Depreciation and amortization expense	11.7	1.0	—	12.7
General and administrative expense	11.4	2.8	—	14.2
Total operating costs and expenses	746.6	350.0	—	1,096.6
Operating income	37.9	9.8	—	47.7
Interest expense, net	(0.3)	—	—	(0.3)
Earnings from equity method investments	0.4	—	25.3	25.7
Income tax expense	—	(3.3)	—	(3.3)
Net income	$ 38.0	$ 6.5	$ 25.3	$ 69.8

Year Ended December 31, 2004

	DCP Midstream Partners, LP and Predecessor	Wholesale Propane Logistics Business	East Texas and Discovery	Combined DCP Midstream Partners, LP
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 489.7	$ 325.7	$ —	$ 815.4
Transportation and other	19.8	(1.2)	—	18.6
Total operating revenues	509.5	324.5	—	834.0
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	452.6	308.0	—	760.6
Operating and maintenance expense	13.6	6.2	—	19.8
Depreciation and amortization expense	12.6	2.1	—	14.7
General and administrative expense	6.5	2.2	—	8.7
Total operating costs and expenses	485.3	318.5	—	803.8
Operating income	24.2	6.0	—	30.2
Earnings from equity method investments	0.6	—	17.0	17.6
Impairment of equity method investment	(4.4)	—	—	(4.4)
Income tax expense	—	(2.5)	—	(2.5)
Net income	$ 20.4	$ 3.5	$ 17.0	$ 40.9

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; (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 with our acquisition of Discovery includes an additional annual fee of $0.2 million; (5) effective August 2007, includes an additional annual fee of $0.6 million for general and administrative expenses payable to DCP Midstream, LLC to account for additional services provided to us; and (6) effective with our acquisition of the MEG subsidiaries in August 2007, includes an additional annual fee of $1.6 million.

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, 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).

Competition

None of DCP Midstream, LLC, nor any of its affiliates, including Spectra Energy and ConocoPhillips, is restricted, under either the partnership agreement or the Omnibus Agreement, from competing with us. DCP Midstream, LLC and any of its affiliates, including Spectra Energy and ConocoPhillips, may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

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.

In connection with our acquisitions of East Texas and Discovery from DCP Midstream, LLC, an affiliate of DCP Midstream, LLC will indemnify us for one year following the closing for the breach of the representations and warranties made under the acquisition agreement and certain environmental matters and tax matters associated with these assets that were identified at the time of closing and that were attributable to periods prior to the closing date. In addition, the same affiliate of DCP Midstream, LLC agreed to indemnify us for one year after closing for the underpayment of trade payables that pertain to periods prior to closing and agreed to indemnify us for two years after closing for any claims for fines or penalties of any governmental authority for periods prior to the closing and that are associated with certain East Texas assets that were formerly owned by Gulf South and UP Fuels. The indemnity obligation for breach of certain representations and warranties is not effective until claims exceed in the aggregate $2.7 million and is subject to a maximum liability of $27.0 million. This indemnity obligation for all other claims other than a breach of the representations and warranties does not become effective until an individual claim or series of related claims exceed $50,000.

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 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 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 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 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 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 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.

In the second quarter of 2006, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will make capital contributions to us as reimbursement for capital projects, which were forecasted to be completed prior to our initial public offering, but were not completed by that date. Pursuant to the letter agreement, DCP Midstream, LLC made capital contributions to us of $3.4 million during 2006, to reimburse us for the capital costs we incurred, primarily for growth capital projects. At December 31, 2006, all of these projects were completed.

We had an operating lease with an affiliate during the years ended December 31, 2005 and 2004. Operating lease expense related to this lease was $0.7 million and $2.8 million for the years ended December 31, 2005 and 2004, respectively.

DCP Midstream, LLC was a significant customer during the six months ended June 30, 2007 and 2006 (unaudited), and during the years ended December 31, 2006, 2005 and 2004.

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 (unaudited), $1.2 million (unaudited), $3.9 million, $0.2 million and $0.3 million of capital reimbursements during the six months ended June 30, 2007 and 2006 and the years ended December 31, 2006, 2005 and 2004, respectively.

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

	Six Months Ended June 30, 2007 (unaudited)	Six Months Ended June 30, 2006 (unaudited)	Year Ended December 31, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
DCP Midstream, LLC:					
Sales of natural gas, propane, NGLs and condensate	$113.9	$120.9	$231.7	$108.8	$71.6
Transportation and processing services	$ 2.9	$ 2.5	$ 4.8	$ 0.3	$ 0.6
Purchases of natural gas, propane and NGLs	$ 70.0	$ 48.0	$102.9	$134.4	$94.4
(Losses) gains from non-trading derivative activity	$ (0.5)	$ (0.5)	$ 0.1	$ (0.9)	$ (1.9)
General and administrative expense	$ 4.7	$ 3.8	$ 8.1	$ 9.1	$ 7.8
Duke Energy:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ —	$ 1.4	$10.3
Transportation and processing services	$ —	$ —	$ —	$ 0.3	$ 0.5
Purchases of natural gas, propane and NGLs	$ —	$ 1.9	$ 3.4	$ 4.7	$ 3.4
ConocoPhillips:					
Sales of natural gas, propane, NGLs and condensate	$ 2.7	$ 0.1	$ 1.1	$ 7.3	$ 3.7
Transportation and processing services	$ 5.0	$ 3.5	$ 8.0	$ 10.0	$ 9.9
Purchases of natural gas, propane and NGLs	$ 13.5	$ 5.7	$ 12.9	$ 18.7	$18.6

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

	June 30, 2007 (unaudited)	December 31, 2006	December 31, 2005
DCP Midstream, LLC:			
Accounts receivable	$ 19.9	$30.0	$53.5
Accounts payable	$ 19.5	$46.6	$15.9
Spectra Energy:			
Accounts receivable	$ 0.3	$ —	$ —
Duke Energy:			
Accounts receivable	$ —	$ 0.2	$ 0.4
Accounts payable	$ —	$ 1.8	$24.0
ConocoPhillips:			
Accounts receivable	$ 10.2	$ 4.6	$ 2.6
Accounts payable	$ 2.1	$ 2.0	$ 2.5

6. Property, Plant and Equipment

A summary of property, plant and equipment by classification is as follows ($ in millions):

	Depreciable Life	June 30, 2007 (unaudited)	December 31, 2006	December 31, 2005
Gathering systems	15 — 30 Years	$ 286.3	$ 107.3	$ 95.9
Processing plants	25 — 30 Years	53.2	53.2	53.4
Terminals	25 — 30 Years	9.2	8.2	8.2
Transportation	25 — 30 Years	139.4	139.6	127.4
General plant	3 — 5 Years	2.7	3.6	3.6
Construction work in progress		20.9	16.2	11.4
Property, plant and equipment		511.7	328.1	299.9
Accumulated depreciation		(141.0)	(133.4)	(121.2)
Property, plant and equipment, net		$ 370.7	$ 194.7	$ 178.7

Depreciation expense was $7.6 million (unaudited) and $6.1 million (unaudited) for the six months ended June 30, 2007 and 2006, respectively, and $12.4 million, $12.0 million and $13.1 million for the years ended December 31, 2006, 2005 and 2004, respectively.

In addition, property, plant and equipment includes $0.9 million (unaudited) and $1.0 million (unaudited), and $1.4 million, $1.1 million and $0.1 million of non-cash additions for the six months ended June 30, 2007 and 2006, and for the years ended December 31, 2006, 2005 and 2004, respectively.

Asset Retirement Obligations — Our asset retirement obligations relate primarily to the retirement of various gathering pipelines and processing facilities, obligations related to right-of-way easement agreements, and contractual leases for land use. We adjust our asset retirement obligation each quarter for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows. The asset retirement obligation, included in other long-term liabilities in the consolidated balance sheets, was $1.1 million (unaudited), $0.5 million and $0.3 million at June 30, 2007, and December 31, 2006 and 2005, respectively. Accretion expense for the six months ended June 30, 2007 and 2006 (unaudited), and for the years ended December 31, 2006, 2005 and 2004 was not significant.

7. Goodwill and Intangible Assets

Goodwill consists of the amount that was recognized by DCP Midstream, LLC when it acquired certain assets which are now included in our Wholesale Propane Logistics segment, and was allocated based on fair value to the wholesale propane logistics business in order to present historical information about the assets we acquired in November 2006. As this was a transaction among entities under common control, our financial information includes the results of our wholesale propane logistics business for all periods presented. There were no changes in the $29.3 million carrying amount of goodwill during the six months ended June 30, 2007 (unaudited) or the years ended December 31, 2006 or 2005. We perform an annual goodwill impairment test, and update the test during interim periods if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying amount. We use a discounted cash flow analysis supported by market valuation multiples to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, estimated future cash flows and an estimated run rate of general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. Our annual goodwill impairment test indicated that our reporting unit’s fair value exceeded its carrying or book value; therefore, we have determined that there is no indication of impairment.

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 consolidated balance sheets as intangible assets, and are as follows ($ in millions):

	June 30, 2007 (unaudited)	December 31, 2006	December 31, 2005
Gross carrying amount	$ 16.9	$ 4.4	$11.0
Accumulated amortization	(1.9)	(1.6)	(7.8)
Intangible assets, net	$ 15.0	$ 2.8	$ 3.2

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.

One customer has notified us that they intend to exercise their early termination right prior to the end of the contract term. Accordingly, we are not amortizing the estimated termination fee of $0.5 million, which is included in the $15.0 million of intangible assets, net in the above table.

For the six months ended June 30, 2007 and 2006, we recorded amortization expense associated with these intangibles of $0.3 million (unaudited) for both periods, and for each of the years ended December 31, 2006, 2005 and 2004, we recorded amortization expense associated with these intangibles of $0.4 million, $0.7 million, and $1.6 million, respectively. As of June 30, 2007 (unaudited), the remaining amortization periods for these contracts range from approximately two to 20 years, with a weighted-average remaining period of approximately 15 years.

Estimated future amortization for these contracts is as follows ($ in millions):

	(unaudited)
Remainder of 2007	$ 0.6
2008	1.1
2009	0.9
2010	0.9

	(unaudited)
2011	0.9
Thereafter	10.1
Total	$ 14.5

8. Equity Method Investments

We have four investments accounted for using the equity method. The following table includes our percentage of ownership and the carrying value of our investments as of the indicated dates ($ in millions):

	Percentage of Ownership as of June 30, 2007, and December 31, 2006 and 2005	Carrying Value as of June 30, 2007 (unaudited)	December 31, 2006	December 31, 2005
Discovery Producer Services LLC	40%	$ 110.6	$ 113.4	$ 101.8
DCP East Texas Holdings, LLC	25%	51.4	50.9	48.4
Black Lake Pipe Line Company	45%	6.2	5.7	5.3
Other	50%	0.2	0.2	0.2
Total equity method investments		$ 168.4	$ 170.2	$ 155.7

Discovery operates a 600 MMcf/d cryogenic natural gas processing plant near Larose, Louisiana, a 32,000 Bbl/d natural gas liquids fractionator plant near Paradis, Louisiana, a natural gas pipeline from offshore deep water in the Gulf of Mexico that transports gas to our processing plant in Larose, Louisiana with a design capacity of 600 MMcf/d and approximately 173 miles of pipe, and several laterals expanding their presence in the Gulf. There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of $46.1 million (unaudited), $48.6 million and $53.5 million at June 30, 2007, and December 31, 2006 and 2005, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Discovery.

East Texas is engaged in the business of gathering, transporting, treating, compressing, processing, and fractionating natural gas and natural gas liquids, or NGLs. Their operations, located near Carthage, Texas, include a natural gas processing complex with a total capacity of 780 million cubic feet per day. The facility is connected to their 845 mile gathering system, as well as third party gathering systems. The complex is adjacent to their Carthage Hub, which delivers residue gas to interstate and intrastate pipelines. The Carthage Hub, with an aggregate delivery capacity of 1.5 billion cubic feet per day, acts as a key exchange point for the purchase and sale of residue gas.

Black Lake owns a 317-mile NGL pipeline, with a throughput capacity of approximately 40 MBbls/d. The pipeline receives NGLs from a number of gas plants in Louisiana and Texas. There was a deficit between the carrying amount of the investment and the underlying equity of Black Lake of $6.5 million (unaudited), $6.7 million and $7.0 million at June 30, 2007, and December 31, 2006 and 2005, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Black Lake.

Prior to December 7, 2005, DCP Midstream Partners Predecessor held a 50% interest in Black Lake. Upon completion of our initial public offering, DCP Midstream, LLC retained a 5% interest in Black Lake.

Earnings from equity method investments for the six months ended June 30, 2007 and 2006, and for the years ended December 31, 2006, 2005 and 2004, were as follows ($ in millions):

	Six Months Ended June 30, 2007 (unaudited)	Six Months Ended June 30, 2006 (unaudited)	Year Ended December 31, 2006	2005	2004
Discovery Producer Services LLC	$ 7.6	$ 8.6	$16.9	$ 10.8	$ 7.8
DCP East Texas Holdings, LLC	4.7	7.1	12.0	14.5	9.2
Black Lake Pipe Line Company and other	0.5	0.1	0.3	0.4	0.6
Total earnings from equity method investments	$ 12.8	$ 15.8	$29.2	$ 25.7	$ 17.6
Distributions from equity method investments	$ 18.5	$ 11.1	$25.9	$ 36.7	$ 13.4
Earnings from equity method investments, net of distributions	$ (5.7)	$ 4.7	$ 3.3	$ (11.0)	$ 4.2

The following summarizes financial information of our equity method investments (unaudited) ($ in millions):

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006	Year Ended December 31, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
Statements of operations:					
Operating revenue	$ 323.2	$ 365.4	$ 686.9	$ 672.1	$ 489.6
Operating expenses	$(291.3)	$(323.1)	$(612.2)	$(594.8)	$(440.7)
Net income	$ 32.6	$ 43.1	$ 77.4	$ 77.9	$ 49.5

	June 30, 2007	December 31, 2006	December 31, 2005
Balance sheet:			
Current assets	$ 82.9	$108.9	$106.7
Non-current assets	634.5	630.7	634.3
Current liabilities	88.8	94.8	109.7
Non-current liabilities	6.6	6.0	1.8
Net assets	$622.0	$638.8	$629.5

9. Impairment of Equity Method Investment

In the third quarter of 2004, we recognized an other-than-temporary impairment of our investment in Black Lake totaling $4.4 million as impairment of equity method investment, included in the consolidated statements of operations. This investment was written down to fair value, which was determined based on management's best estimates of discounted future cash flow models. The charge associated with this impairment is recorded in the NGL Logistics segment.

10. Estimated Fair Value of Financial Instruments

We have determined the following fair value amounts using available market information and appropriate valuation methodologies. However, considerable judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize in a current market exchange. The use of different market assumptions and/or estimation methods may have a material effect on the estimated fair value amounts. The following summarizes the estimated fair value of financial instruments ($ in millions):

	June 30, 2007		December 31, 2006		December 31, 2005	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(unaudited)					
Restricted investments	$ —	$ —	$ 102.0	$ 102.0	$ 100.4	$ 100.4
Accounts receivable	$ 70.6	$ 70.6	$ 78.2	$ 78.2	$ 122.2	$ 122.2
Accounts payable	$ 92.3	$ 92.3	$ 117.3	$ 117.3	$ 138.3	$ 138.3
Unrealized (losses) gains on non-trading derivative and hedging instruments	$ (15.2)	$ (15.2)	$ 7.3	$ 7.3	$ 0.4	$ 0.4
Long-term debt	$ 249.0	$ 249.0	$ 268.0	$ 268.0	$ 210.1	$ 210.1

The fair value of restricted investments, accounts receivable and accounts payable are not materially different from their carrying amounts because of the short term nature of these instruments or the stated rates approximating market rates. Unrealized gains and unrealized losses on mark-to-market and hedging instruments are carried at fair value.

The carrying value of long-term debt approximates fair value, as the interest rate is variable and reflects current market conditions.

11. Debt

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

	Principal Amount		
	June 30, 2007 (unaudited)	December 31, 2006	December 31, 2005
Revolving credit facility, weighed-average interest rate of 5.77% at June 30, 2007, due June 21, 2012	$ 249.0	$168.0	$110.0
Term loan facility, interest rate of 5.47% at December 31, 2006, due December 7, 2010	—	100.0	100.1
Total long-term debt	$ 249.0	$268.0	$210.1

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 (unaudited) and December 31, 2006, we had $0.2 million of letters of credit outstanding. There were no letters of credit outstanding at December 31, 2005. 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 consolidated balance sheet as of December 31, 2006. In June 2007, we incurred $0.5 million (unaudited) of debt issuance costs associated with the Amended Credit Agreement. In December 2005, we incurred $0.7 million of debt issuance costs associated with the Credit Agreement. These expenses are deferred as other non-current assets in the consolidated balance sheet and will be amortized over the term of the Credit Agreement.

As of June 30, 2007, and December 31, 2006 and 2005, $0.4 million (unaudited), $1.1 million and $0.8 million, respectively, was recorded as accrued interest payable in the consolidated balance sheets. We paid $10.0 million (unaudited) in interest and facility fees, net of capitalized interest of $0.2 million (unaudited), during the six months ended June 30, 2007. We paid $11.1 million in interest and facility fees, net of capitalized interest of $0.4 million, in 2006. We paid $0.5 million of facility fees during 2005.

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.

Guarantor Financial Information

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. In connection with the universal shelf registration statement, all of our subsidiaries, or Guarantors, have fully and unconditionally guaranteed, on a joint and several basis, any debt obligations we may register. DCP Midstream Partners, LP, the parent company of the Guarantors and the co-issuer of the debt obligations with its wholly-owned finance subsidiary, DCP Midstream Partners Finance Corp., has no independent assets or operations. There are no significant restrictions on DCP Midstream Partners, LP's ability to obtain funds from its subsidiaries by dividend or loan.

12. 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 (unaudited) — 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. In August 2007, these units were issued to our general partner.

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.

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.

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

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

	Six Months Ended June 30, 2007 (unaudited)	Six Months Ended June 30, 2006 (unaudited)	Year Ended December 31, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
Commodity cash flow hedges:					
Losses due to ineffectiveness	$ —	$ (0.5)	$(0.3)	$ 0.3	$—
Gains reclassified into earnings as a result of settlements	$ 1.8	$ 0.7	$ 2.6	$—	$—
Commodity non-trading derivative activity:					
(Losses) gains from non-trading derivative activity	$ (15.0)	$ (0.5)	$ 0.1	$(0.9)	$(1.9)
Interest rate cash flow hedges:					
Gains reclassified into earnings as a result of settlements	$ 0.3	$ —	$ 0.1	$—	$—

	June 30, 2007 (unaudited)	December 31, 2006	December 31, 2005	December 31, 2004
Commodity cash flow hedges:				
Net deferred (losses) gains in AOCI	$ (2.0)	$6.9	$ 0.4	$—
Interest rate cash flow hedges:				
Net deferred gains in AOCI	$ 1.5	$0.4	$—	$—

For the six months ended June 30, 2007 and 2006 (unaudited), and the year ended December 31, 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.

We are exposed to market risks, including changes in commodity prices and interest rates. We may use financial instruments such as forward contracts, swaps and futures to mitigate the effects of the identified risks. In general, we attempt to mitigate risks related to the variability of future cash flows resulting from changes in applicable commodity prices or interest rates so that we can maintain cash flows sufficient to meet debt service, required capital expenditures, distribution objectives and similar requirements. We have established a comprehensive risk management policy, or the Risk Management Policy, and a risk management committee, to monitor and manage market risks associated with commodity prices and interest rates. Our Risk Management Policy prohibits the use of derivative instruments for speculative purposes.

Commodity Price Risk — 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. As an owner and operator of natural gas processing and other midstream assets, we have an inherent exposure to market variables and commodity price risk. The amount and type of price risk is dependent on the underlying natural gas contracts to purchase and process raw natural gas. Risk is also dependent on the types and mechanisms for sales of natural gas and NGLs, and related products produced, processed, transported or stored.

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. To the extent that we carry propane inventories or our sales and supply arrangements are not aligned we are exposed to market variables and commodity price risk. The amount and type of price risk is dependent on the mechanisms and locations for purchases, sales, transportation and storage of propane.

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.

Credit Risk — In the Natural Gas Services segment, we sell natural gas to marketing affiliates of natural gas pipelines, marketing affiliates of integrated oil companies, marketing affiliates of DCP Midstream, LLC, national wholesale marketers, industrial end-users and gas-fired power plants. In the Wholesale Propane Logistics segment, we sell primarily to retail propane distributors. In the NGL Logistics segment, our principal customers include an affiliate of DCP Midstream, LLC, producers and marketing companies. 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 and guidelines. The 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.

Commodity Cash Flow Hedges — We executed a series of derivative financial transactions, referred to as swap contracts. As a result of these transactions, we have mitigated a significant portion of our expected natural gas and NGL commodity price risk through 2011 relating to our percentage-of-proceeds gathering and processing contracts and of our expected condensate commodity price risk relating to condensate recovered from gathering operations.

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 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 consolidated statements of operations in the same accounts as the item being hedged. As of June 30, 2007, $0.2 million (unaudited) 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; however, due to the volatility of the commodities markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings.

Commodity Fair Value Hedges — We use fair value hedges to 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 six months ended June 30, 2007 and 2006 (unaudited), and for the years ended December 31, 2006, 2005 and 2004, 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 six months ended June 30, 2007 and 2006 (unaudited) and during the years ended December 31, 2006, 2005 and 2004, 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.

Normal Purchases and Normal Sales — If a contract qualifies and is designated as a normal purchase or normal sale, no recognition of the contract's fair value in the consolidated financial statements is required until the associated delivery period impacts earnings. We have applied this accounting election for contracts involving the purchase or sale of physical natural gas, propane or NGLs in future periods.

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 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 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. In March 2007, DCP Midstream, LLC entered into a crude oil swap, or the Swap, a non-trading derivative, to mitigate a portion of the price risk from July 2007 through December 2012. The Swap is for a total of approximately 1.9 million barrels at $66.72 per barrel. We acquired the Swap from DCP Midstream, LLC in July 2007. 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 consolidated balance sheets. As of June 30, 2007, $0.4 million (unaudited) 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; 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.

14. Equity-Based Compensation

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

	Six Months Ended June 30,		Year Ended December 31,		
	2007	2006	2006	2005	2004
	(unaudited)				
Performance Units	$ 0.5	$ 0.1	$0.2	$—	$—
Phantom Units	0.4	0.2	0.4	—	—
Total compensation cost	$ 0.9	$ 0.3	$0.6	$—	$—

On November 28, 2005, the board of directors of our General Partner adopted the LTIP for employees, consultants and directors of our 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 limited partner units, or LPUs, phantom units, unit options and substitute awards, and, with respect to unit options and phantom units, the grant of 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 are 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. We first granted awards under the LTIP during 2006.

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 (unaudited) 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 (a)	Grant Date Weighted-Average Price per Unit	Measurement Date Weighted-Average Price per Unit
Outstanding at December 31, 2005	—	$ —	
Granted	40,560	$ 26.96	
Forfeited	(17,470)	$ 26.96	
Outstanding at December 31, 2006	23,090	$ 26.96	
Granted	29,610	$ 37.23	
Outstanding at June 30, 2007 (unaudited)	52,700	$ 32.73	$ 46.62
Expected to vest (unaudited)	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 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 (unaudited) 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 Weighted-Average Price per Unit
Outstanding at December 31, 2005	—	$ —	
Granted	35,900	$ 24.05	
Forfeited	(11,200)	$ 24.05	
Outstanding at December 31, 2006	24,700	$ 24.05	
Granted	4,000	$ 42.69	
Forfeited	(2,668)	$ 24.05	
Outstanding at June 30, 2007 (unaudited)	26,032	$ 26.91	$ 46.62
Expected to vest (unaudited)	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 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 (unaudited). No awards were vested or settled during the six months ended June 30, 2006 or the year ended December 31, 2006.

15. Income Taxes

We are structured as a master limited partnership, which is a pass-through entity for U.S. income tax purposes. The income tax expense reflected on our consolidated statements of operations is applicable to our wholesale propane logistics business. On

December 7, 2005, our wholesale propane logistics business changed its tax structure, which resulted in its activities changing from taxable to non-taxable for United States income tax purposes.

Income tax expense consisted of the following for the years ended December 31, 2005 and 2004 ($ in millions):

	Year Ended December 31, 2005	Year Ended December 31, 2004
Current:		
Federal	$ 3.0	$ 2.0
State	0.8	0.6
Deferred:		
Federal	(0.4)	(0.1)
State	(0.1)	—
Total income tax expense	$ 3.3	$ 2.5

A reconciliation of the actual income tax expense and the amount computed by applying the federal statutory rate of 35% to the income before income taxes is as follows ($ in millions):

	Year Ended December 31, 2005	Year Ended December 31, 2004
Federal income tax at statutory rate	$ 3.4	$ 2.1
State income taxes, net of federal benefit	0.6	0.5
Change in tax structure	(0.5)	—
Depreciation and amortization	—	0.4
Net trading margins	—	(0.4)
Other	(0.2)	(0.1)
Total income tax expense	$ 3.3	$ 2.5

The change in tax structure resulted in the reversal of the net deferred tax liabilities in the year ended December 31, 2005. Accordingly, we had no deferred tax balances as of June 30, 2007 (unaudited), December 31, 2006 or 2005, and no income tax expense for the six months ended June 30, 2007 or 2006 (unaudited), or the year ended December 31, 2006.

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

The Texas margin tax is considered an income tax for purposes of calculating the deferred tax liability. GAAP requires that deferred taxes be adjusted upon enactment of new tax law, which occurred in 2006. The deferred tax liabilities associated with the Texas margin tax were insignificant.

16. 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 limited partner unit. This result occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the incentive distribution rights of the general partner, even though we make distributions on the basis of Available Cash and not earnings. In periods in which our aggregate net income does not exceed the First Target Distribution Level, there is no impact on our calculation of earnings per limited partner unit. During the six months ended June 30, 2007 (unaudited), 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 six months ended June 30, 2006 (unaudited), 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 year ended December 31, 2006, our aggregate net income per limited partner unit exceeded the Second Target Distribution level, and as a result we allocated $1.3 million in additional earnings to the general partner.

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

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

	Six Months Ended June 30,		Year ended December 31,	
	2007	2006	2006	2005
	(unaudited)			
Net income	$ 16.6	$ 32.0	$ 61.9	$ 69.8
Less:				
Net income attributable to predecessor operations	(3.6)	(17.8)	(26.6)	(65.1)
Net income attributable to the partnership	13.0	14.2	35.3	4.7
Less: General partner interest in net income	(0.6)	(0.3)	(0.7)	(0.1)
Limited partners' interest in net income	12.4	13.9	34.6	4.6
Less: Additional earnings allocation to general partner	(1.8)	—	(1.3)	(1.1)
Net income available to limited partners	$ 10.6	$ 13.9	$ 33.3	$ 3.5
Net income per limited partner unit — basic and diluted	$ 0.60	$ 0.79	$ 1.90	$ 0.20

17. Commitments and Contingent Liabilities

Litigation

Driver — In August 2007, Driver Pipeline Company, Inc., or Driver, filed a lawsuit against DCP Midstream, LP, an affiliate of the owner of our general partner, in District Court, Jackson County, Texas. The litigation stems from an ongoing commercial dispute involving the construction of our Wilbreeze pipeline, which was completed in December 2006. Driver was the primary contractor for construction of the pipeline and the construction process was managed for us by DCP Midstream, LP. Driver claims damages in the amount of $2.4 million for breach of contract. We believe Driver's position in this litigation is without merit and we intend to vigorously defend ourselves against this claim. 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 financial position.

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.

Seabreeze — In June 2006, a DCP Midstream, LLC customer whose plant is served by our Seabreeze pipeline notified DCP Midstream, LLC that off specification NGLs had been received into their facility. Our Seabreeze pipeline transports NGLs owned by DCP Midstream, LLC that are delivered to the customer under the terms of a transportation agreement. The customer sent a letter to DCP Midstream, LLC claiming that the off specification NGLs delivered to their facility caused damage to their plant facility. On December 29, 2006 we entered into a settlement agreement with the customer to settle all our issues regarding this matter, and our portion of the settlement was $0.3 million.

Other — We are not a party to any other significant legal proceedings, but are a party to various administrative proceedings, 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.

Insurance — In 2005, DCP Midstream, LLC carried insurance coverage, which included our assets and operations, with an affiliate of Duke Energy. Beginning in 2006, DCP Midstream, LLC elected to carry our property and excess liability insurance coverage with an affiliate of Duke Energy and an affiliate of ConocoPhillips. DCP Midstream, LLC provides our remaining insurance coverage with a third party insurer. DCP Midstream, LLC's insurance coverage includes: (1) commercial general public liability insurance for liabilities arising to third parties for bodily injury and property damage resulting from operations; (2) workers' compensation liability coverage to required statutory limits; (3) automobile liability insurance for all owned, non-owned and hired vehicles covering liabilities to third parties for bodily injury and property damage; (4) excess liability insurance above the established primary limits for commercial general liability and automobile liability insurance; (5) property insurance covering the replacement value of all real and personal property damage, including damages arising from boiler and machinery breakdowns, windstorms, earthquake, flood damage and business interruption/extra expense; and (6) directors and officers insurance covering our directors and officers for acts related to our activities. All coverages are subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations. Effective August 2006, we contracted with a third party insurer for our property and primary liability insurance coverage.

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

Indemnification — 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.

Other Commitments and Contingencies — We utilize assets under operating leases in several areas of operation. Consolidated rental expense, including leases with no continuing commitment, amounted to $5.8 million (unaudited), $5.5 million (unaudited), $11.2 million, $10.3 million, and $1.5 million for the six months ended June 30, 2007 and 2006, and for the years ended December 31, 2006, 2005 and 2004, respectively. Rental expense for leases with escalation clauses is recognized on a straight line basis over the initial lease term.

Minimum rental payments under our various operating leases in the year indicated are as follows at June 30, 2007 ($ in millions):

	(unaudited)
Remainder of 2007	$ 4.8
2008	8.4
2009	6.5
2010	5.8
2011	4.8
Thereafter	10.7
Total minimum rental payments	$ 41.0

18. 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. The Natural Gas Services segment also consists of our 25% limited liability company interest in East Texas, our 40% limited liability company interest in Discovery, and the Swap acquired in July 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. Our equity interest consists of 45% from December 7, 2005 through December 31, 2006, and 50% in 2004 and the period from January 1, 2005 through December 6, 2005. DCP Midstream, LLC owns a 5% interest in Black Lake, effective with the date of our initial public offering, and an affiliate of BP PLC owns the remaining interest and is the operator of Black Lake.

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):

Six Months Ended June 30, 2007 (unaudited)

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(c)	Total
Total operating revenue	$ 187.7	$ 227.0	$ 3.6	$ —	$418.3
Gross margin (a)	$ 25.3	$ 14.6	$ 2.3	$ —	$ 42.2
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	12.3	—	0.5	—	12.8
Interest income	—	—	—	2.5	2.5
Interest expense	—	—	—	(8.4)	(8.4)
Net income (loss)	$ 23.7	$ 8.9	$ 1.6	$ (17.6)	$ 16.6
Capital expenditures	$ 4.1	$ 2.6	$ 0.9	$ —	$ 7.6

Six Months Ended June 30, 2006 (unaudited)

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(c)	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	15.7	—	0.1	—	15.8
Interest income	—	—	—	3.0	3.0
Interest expense	—	—	—	(5.2)	(5.2)
Net income (loss)	$ 38.4	$ 3.7	$ 1.4	$ (11.5)	$ 32.0
Capital expenditures	$ 5.9	$ 5.2	$ 1.0	$ —	$ 12.1

Year ended December 31, 2006:

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(c)	Total
Total operating revenue	$ 415.3	$ 375.2	$ 5.3	$ —	$795.8
Gross margin (a)	$ 75.3	$ 16.0	$ 4.1	$ —	$ 95.4
Operating and maintenance expense	(13.5)	(8.6)	(1.6)	—	(23.7)
Depreciation and amortization expense	(11.1)	(0.8)	(0.9)	—	(12.8)
General and administrative expense	—	—	—	(12.9)	(12.9)
General and administrative expense — affiliate	—	—	—	(8.1)	(8.1)
Earnings from equity method investments	28.9	—	0.3	—	29.2
Interest income	—	—	—	6.3	6.3
Interest expense	—	—	—	(11.5)	(11.5)
Net income (loss)	$ 79.6	$ 6.6	$ 1.9	$ (26.2)	$ 61.9
Capital expenditures	$ 6.5	$ 9.4	$ 11.3	$ —	$ 27.2

Year ended December 31, 2005:

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(c)	Total
Total operating revenues	$ 592.8	$ 359.8	$ 191.7	$ —	$1,144.3
Gross margin (a)	$ 71.4	$ 21.8	$ 3.8	$ —	$ 97.0
Operating and maintenance expense	(14.0)	(8.2)	(0.2)	—	(22.4)
Depreciation and amortization expense	(10.8)	(1.0)	(0.9)	—	(12.7)
General and administrative expense	—	—	—	(5.1)	(5.1)
General and administrative expense — affiliate	—	—	—	(9.1)	(9.1)
Earnings from equity method investments	25.3	—	0.4	—	25.7
Interest income	—	—	—	0.5	0.5
Interest expense	—	—	—	(0.8)	(0.8)
Income tax expense (b)	—	—	—	(3.3)	(3.3)
Net income (loss)	$ 71.9	$ 12.6	$ 3.1	$ (17.8)	$ 69.8
Capital expenditures	$ 7.9	$ 2.9	$ —	$ —	$ 10.8

Year ended December 31, 2004:

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(c)	Total
Total operating revenues	$ 353.3	$ 324.5	$ 156.2	$ —	$834.0
Gross margin (a)	$ 53.6	$ 16.5	$ 3.3	$ —	$ 73.4
Operating and maintenance expense	(13.4)	(6.2)	(0.2)	—	(19.8)
Depreciation and amortization expense	(11.7)	(2.1)	(0.9)	—	(14.7)
General and administrative expense	—	—	—	(0.9)	(0.9)
General and administrative expense — affiliate	—	—	—	(7.8)	(7.8)
Earnings from equity method investments	17.0	—	0.6	—	17.6
Impairment of equity method investment	—	—	(4.4)	—	(4.4)
Income tax expense (b)	—	—	—	(2.5)	(2.5)
Net income (loss)	$ 45.5	$ 8.2	$ (1.6)	$ (11.2)	$ 40.9
Capital expenditures	$ 2.8	$ 0.2	$ 0.3	$ —	$ 3.3

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

	June 30, 2007 (unaudited)	December 31, 2006	December 31, 2005
Segment non-current assets:			
Natural Gas Services (d)	$ 496.5	$311.7	$303.0
Wholesale Propane Logistics	51.8	50.2	40.4
NGL Logistics	35.4	35.1	23.5
Other (e)	6.0	109.3	106.8
Total non-current assets	589.7	506.3	473.7
Current assets	159.3	159.6	206.4
Total assets	$ 749.0	$665.9	$680.1

(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) Income tax expense relates to our wholesale propane logistics business, which changed its tax status in December 2005.

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

(d) 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 (unaudited) in May 2007. Long-term assets for our Natural Gas Services segment include the effects of our 25% equity interest in East Texas, our 40% equity interest in Discovery and the Swap acquired in July 2007.

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

19. Quarterly Financial Data (Unaudited)

In July 2007, we acquired our 25% limited liability company interest in East Texas, our 40% limited liability company interest in Discovery and the Swap. Accordingly, the results of operations by quarter have been retroactively adjusted for to include the results of our wholesale propane logistics business, and for East Texas, Discovery and the Swap, for all periods presented.

Our consolidated results of operations by quarter, as previously reported, for the six months ended June 30, 2007 and the years ended December 31, 2006 and 2005 were as follows ($ in millions, except per unit amounts):

2007	First	Second	Six Months Ended June 30, 2007
Total operating revenues	$240.1	$186.9	$ 427.0
Operating income	$ 14.4	$ 4.0	$ 18.4
Net income	$ 12.5	$ 0.5	$ 13.0
Limited partners’ interest in net income (a)	$ 12.2	$ 0.2	$ 12.4
Basic net income per limited partner unit (a)	$ 0.58	$ 0.01	$ 0.60

2006	First	Second	Third	Fourth	Year Ended December 31, 2006
Total operating revenues	$265.4	$160.1	$162.8	$207.5	$ 795.8
Operating income	$ 9.1	$ 9.3	$ 7.3	$ 12.2	$ 37.9
Net income	$ 8.0	$ 8.3	$ 6.1	$ 10.6	$ 33.0
Limited partners’ interest in net income (a)(b)	$ 5.3	$ 8.6	$ 9.5	$ 11.1	$ 34.6
Basic net income per limited partner unit (a)(b)	$ 0.30	$ 0.47	$ 0.51	$ 0.55	$ 1.90

2005	First	Second	Third	Fourth	Year Ended December 31, 2005
Total operating revenues	$264.4	$202.5	$285.0	$392.4	$ 1,144.3
Operating income	$ 15.1	$ 7.2	$ 2.7	$ 22.7	$ 47.7
Net income	$ 11.9	$ 7.4	$ 6.0	$ 19.2	$ 44.5
Limited partners’ interest in net income (a)(c)	$ —	$ —	$ —	$ 4.6	$ 4.6
Basic net income per limited partner unit (a)(c)	$ —	$ —	$ —	$ 0.20	$ 0.20

Our combined results of operations by quarter for our 25% limited liability company interest in East Texas, our 40% limited liability company interest in Discovery and the Swap for the six months ended June 30, 2007 and the years ended December 31, 2006 and 2005 were as follows ($ in millions):

2007	First	Second	Six Months Ended June 30, 2007
Total operating revenues	$ (2.9)	$ (5.8)	$ (8.7)
Operating loss	$ (2.9)	$ (5.8)	$ (8.7)
Net income	$ 3.3	$ 0.3	$ 3.6
Limited partners’ interest in net income	N/A	N/A	N/A
Basic net income per limited partner unit	N/A	N/A	N/A

2006	First	Second	Third	Fourth	Year Ended December 31, 2006
Total operating revenues	N/A	N/A	N/A	N/A	N/A
Operating income	N/A	N/A	N/A	N/A	N/A
Net income (loss)	$ 8.3	$ 7.4	$ 8.2	$ 5.0	$ 28.9
Limited partners’ interest in net income	N/A	N/A	N/A	N/A	N/A
Basic net income per limited partner unit	N/A	N/A	N/A	N/A	N/A

2005	First	Second	Third	Fourth	Year Ended December 31, 2005
Total operating revenues	N/A	N/A	N/A	N/A	N/A
Operating income	N/A	N/A	N/A	N/A	N/A
Net income (loss)	$ 6.1	$ 5.1	$ 4.0	$10.1	$ 25.3
Limited partners' interest in net income	N/A	N/A	N/A	N/A	N/A
Basic net income per limited partner unit	N/A	N/A	N/A	N/A	N/A

Our consolidated results of operations by quarter for the six months ended June 30, 2007 and for the years ended December 31, 2006 and 2005 were as follows ($ in millions, except per unit amounts):

2007	First	Second	Six Months Ended June 30, 2007
Total operating revenues	$237.2	$181.1	$ 418.3
Operating income (loss)	$ 11.5	$ (1.8)	$ 9.7
Net income	$ 15.8	$ 0.8	$ 16.6
Limited partners' interest in net income (a)	$ 12.2	$ 0.2	$ 12.4
Basic net income per limited partner unit (a)	$ 0.58	$ 0.01	$ 0.60

2006	First	Second	Third	Fourth	Year Ended December 31, 2006
Total operating revenues	$265.4	$160.1	$162.8	$207.5	$ 795.8
Operating income	$ 9.1	$ 9.3	$ 7.3	$ 12.2	$ 37.9
Net income	$ 16.3	$ 15.7	$ 14.3	$ 15.6	$ 61.9
Limited partners' interest in net income (a)(b)	$ 5.3	$ 8.6	$ 9.5	$ 11.1	$ 34.6
Basic net income per limited partner unit (a)(b)	$ 0.30	$ 0.47	$ 0.51	$ 0.55	$ 1.90

2005	First	Second	Third	Fourth	Year Ended December 31, 2005
Total operating revenues	$264.4	$202.5	$285.0	$392.4	$ 1,144.3
Operating income	$ 15.1	$ 7.2	$ 2.7	$ 22.7	$ 47.7
Net income	$ 18.0	$ 12.5	$ 10.0	$ 29.3	$ 69.8
Limited partners' interest in net income (a)(c)	$ —	$ —	$ —	$ 4.6	$ 4.6
Basic net income per limited partner unit (a)(c)	$ —	$ —	$ —	$ 0.20	$ 0.20

(a) Total limited partners' interest in net income and basic income per limited partner unit excludes the results from our interest in East Texas, Discovery and the Swap for all periods presented.

(b) Total limited partners' interest in net income and basic income per limited partner unit excludes the results from our wholesale propane logistics business for the period January 1, 2006 through October 31, 2006.

(c) Total limited partners' interest in net income and basic income per limited partner unit is calculated using net income earned by us from December 7, 2005 through December 31, 2005, excluding the results from our wholesale propane logistics business.

20. Subsequent Events

On July 1, 2007, we acquired a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery and the Swap from DCP Midstream, LLC for aggregate consideration of approximately $271.3 million, consisting of approximately $243.7 million in cash, including $1.3 million for net working capital and other adjustments, the issuance of 620,404 common units to DCP Midstream, LLC 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 of $245.9 million under our amended credit facility. We are providing these consolidated financial statements to include the effect of this acquisition.

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. These interest rate swaps commenced 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 conjunction with DCP Midstream, LLC's acquisition of MEG in August 2007, we acquired certain subsidiaries of MEG from DCP Midstream, LLC for aggregate consideration of approximately $165.8 million, subject to final closing adjustments. The consideration consisted of approximately $153.8 million of cash and the issuance of 275,735 common units to an affiliate of DCP Midstream, LLC that were valued at approximately $12.0 million. We have incurred post-closing purchase price adjustments to date that include a liability of $9.0 million for net working capital and general and administrative charges. The subsidiaries of MEG own gathering, processing and compression assets in the Piceance and Powder River producing basins. The Piceance Basin assets consist of a 70 percent operating interest in the 31-mile Collbran Valley Gas Gathering system joint venture, which gathers and processes natural gas from over 20,000 dedicated acres in western Colorado. The processing facility capacity is currently being expanded from 60 MMcf/d to 120 MMcf/d. The other partners in the joint venture, Plains Exploration and Delta Petroleum, are also the producers on the system. The Powder River Basin assets include the 1,324-mile Douglas gas gathering system, which gathers approximately 30 MMcf/d of gas and covers more than 4,000 square miles in Wyoming. Also included in the transaction are the idle Painter Unit fractionator and Millis terminal, and associated NGL pipelines in southwest Wyoming. DCP Midstream, LLC will manage and operate these assets on our behalf. We financed this transaction with borrowings under our amended credit facility of $120.0 million, the issuance of common units through a private placement with certain institutional investors and cash on hand. In August 2007, we sold 2,380,952 common units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100 million in the aggregate. In connection with this common unit purchase agreement, we have a registration rights agreement that requires us to register the units within 90 days of the close of the private placement, and have filed a registration statement with the SEC. In addition, the registration rights agreement requires us to use our commercially reasonable efforts to cause the registration statement to become effective within 180 days of the closing of the private placement. If the registration statement covering the common units is not declared effective by the SEC within 180 days of the closing of the private placement, then we will be liable to the purchasers for liquidated damages of 0.25% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period for the first 60 days following the 180th day, increasing by an additional 0.25% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period for each subsequent 60 days, up to a maximum of 1.00% of the product of the purchase price and the number of registrable securities held by the purchasers per 30-day period.

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. The Omnibus Agreement was further amended in August 2007 to include an additional annual fee of $1.6 million in connection with our acquisition of the MEG subsidiaries, described above.

DCP MIDSTREAM PARTNERS, LP

SCHEDULE II — CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

	Balance at Beginning of Period	Charged to Consolidated Statements of Operations	Deductions/ Other	Credit to Consolidated Statements of Operations	Balance at End of Period
			($ in millions)		
December 31, 2006					
Allowance for doubtful accounts	$ 0.3	$ 0.3	$ (0.3)	$ —	$ 0.3
Environmental	0.1	—	—	—	0.1
Other (a)	—	0.3	—	—	0.3
	$ 0.4	$ 0.6	$ (0.3)	$ —	$ 0.7
December 31, 2005					
Allowance for doubtful accounts	$ 0.3	$ 0.1	$ —	$ (0.1)	$ 0.3
Environmental	—	0.2	(0.1)	—	0.1
Other (a)	1.3	—	(1.3)	—	—
	$ 1.6	$ 0.3	$ (1.4)	$ (0.1)	$ 0.4
December 31, 2004					
Allowance for doubtful accounts	$ 0.3	$ —	$ —	$ —	$ 0.3
Environmental	—	—	—	—	—
Other (a)	1.3	—	—	—	1.3
	$ 1.6	$ —	$ —	$ —	$ 1.6

(a) Principally consists of other contingency liabilities, which are included in other current liabilities.