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): May 26, 2010

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 No.)**	**(IRS Employer Identification No.)**

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

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

Not Applicable
(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 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.

DCP Midstream Partners, LP, (the "Partnership") is filing this Current Report on Form 8-K (this "Report") in connection with the anticipated filing with the Securities and Exchange Commission ("SEC") of a shelf registration statement on Form S-3 relating to the offering of securities (the "Securities") of the Partnership and its subsidiary, DCP Midstream Operating, LP ("DCP Operating"). The new shelf registration statement will replace the Partnership's existing shelf registration statement that expires in November 2010. The Securities, including debt securities of DCP Operating that will be unconditionally guaranteed by the Partnership, may be offered for sale from time to time. This Report adds Note 21 to the Partnership's audited consolidated financial statements included within Part II, Item 8 of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2009 (the "2009 Form 10-K"), filed with the SEC on March 11, 2010.

The Partnership is providing the additional note to the Partnership's financial statements to provide condensed consolidating financial information in accordance with Rule 3-10(c) of Regulation S-X promulgated by the SEC because the debt securities may be fully and unconditionally guaranteed by the Partnership. To reflect the addition of Note 21 to the Partnership's 2009 Form 10-K, Part II, Item 8 of the 2009 Form 10-K is being amended in its entirety and is attached as Exhibit 99.1 hereto and is incorporated by reference herein.

Because this Current Report is being filed only for the purposes described above, and only affects the Item specified above, the other information contained in the 2009 Form 10-K remains unchanged. No attempt has been made in this Current Report nor in the Exhibits hereto to modify or update disclosures in the 2009 Form 10-K except as described above. Accordingly, this Current Report should be read in conjunction with the 2009 Form 10-K and the Partnership's filings with the SEC subsequent to the filing of the 2009 Form 10-K, including the Partnership's Quarterly Report on Form 10-Q for the quarter ended March 31, 2010.

Item 9.01. Financial Statements and Exhibits.

(d) Exhibits.

Exhibit Number	Description
Exhibit 23.1	Consent of Deloitte & Touche LLP
Exhibit 99.1	Update to the Partnership's 2009 Form 10-K, Part II, Item 8. Financial Statements and Supplementary Data

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

By:	/s/ Michael S. Richards
Name:	Michael S. Richards
Title:	Vice President, General Counsel and Secretary

May 26, 2010

EXHIBIT INDEX

Exhibit Number	Description
23.1	**Consent of Deloitte & Touche LLP**
99.1	**Update to the Partnership’s 2009 Form 10-K, Part II, Item 8. Financial Statements and Supplementary Data**

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 of our report dated March 10, 2010 (May 26, 2010 as to Note 21), relating to the consolidated financial statements and financial statement schedule of DCP Midstream Partners, LP (which report expresses an unqualified opinion including explanatory paragraphs referring to (a) the preparation of the portion of the DCP Midstream Partners, LP consolidated financial statements attributable to DCP East Texas Holdings, LLC, Discovery Producer Services, LLC, and a non trading derivative instrument from the separate records maintained by DCP Midstream, LLC, (b) the retroactive effect of the April 1, 2009 acquisition of an additional 25.1% of DCP East Texas Holdings, LLC, which was accounted for in a manner similar to a pooling of interests, and (c) the retrospective adjustments related to the adoption of the amended provisions of ASC 810, *Consolidation*, as it pertains to noncontrolling interests, and the adoption of the amended provisions of ASC 260, *Earnings Per Share*, as it pertains to net income per limited partner unit), appearing in this Current Report on Form 8-K of DCP Midstream Partners, LP dated May 26, 2010.

/s/ Deloitte & Touche LLP

Denver, Colorado
May 26, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
DCP Midstream 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, 2009 and 2008, and the related consolidated statements of operations, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2009. Our audits also included the accompanying 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. We did not audit the financial statements of Discovery Producer Services, LLC ("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 $145,727,000 and $145,054,000 at December 31, 2009 and 2008, respectively, and in Discovery's net income of $14,204,000, $13,759,000, and $19,228,000 for the years ended December 31, 2009, 2008, and 2007, 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 the amounts included for Discovery, is based solely on the report of the 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, such consolidated statements present fairly, in all material respects, the financial position of the Company as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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, through July 1, 2007, the portion of the accompanying consolidated financial statements attributable to DCP East Texas Holdings, LLC ("East Texas"), Discovery and a nontrading derivative instrument (the "Swap"), collectively, referred to as "predecessors", have been prepared from the separate records maintained by DCP Midstream, LLC ("Midstream") and may not necessarily be indicative of the conditions that would have existed or the results of operations if the predecessors had been operated as unaffiliated entities. Portions of certain expenses represent allocations made from, and are applicable to Midstream as a whole.

Also, as discussed in Note 1 to the consolidated financial statements, the consolidated financial statements give retroactive effect to the April 1, 2009 acquisition by the Company of an additional 25.1% of East Texas from Midstream, as a combination of entities under common control, and have been accounted for in a manner similar to a pooling of interests as described in Note 1 to the consolidated financial statements.

Also, as discussed in Note 3 to the consolidated financial statements, in 2009, the Company adopted the amended provisions of ASC 810, *Consolidation*, as it pertains to noncontrolling interests, and the amended provisions of ASC 260, *Earnings per Share*, as it pertains to net income per limited partner unit, and as a result, retrospectively adjusted its 2008 and 2007 consolidated financial statements.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2009, based on the criteria established in the *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 10, 2010 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 10, 2010
(May 26, 2010 as to Note 21)

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2.1	$ 61.9
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.5 million and $1.0 million, respectively	78.7	58.8
Affiliates	73.8	57.5
Inventories	34.2	20.9
Unrealized gains on derivative instruments	7.3	15.4
Other	1.6	0.9
Total current assets	197.7	215.4
Restricted investments	10.0	60.2
Property, plant and equipment, net	1,000.1	882.7
Goodwill	92.1	88.8
Intangible assets, net	60.5	47.7
Investments in unconsolidated affiliates	114.6	111.5
Unrealized gains on derivative instruments	2.0	8.6
Other long-term assets	4.5	4.8
Total assets	$1,481.5	$1,419.7
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 85.5	$ 71.6
Affiliates	43.1	36.0
Unrealized losses on derivative instruments	41.5	17.7
Accrued interest payable	0.7	1.3
Other	20.3	36.6
Total current liabilities	191.1	163.2
Long-term debt	613.0	656.5
Unrealized losses on derivative instruments	58.0	26.0
Other long-term liabilities	14.0	11.2
Total liabilities	876.1	856.9
Commitments and contingent liabilities:		
Equity:		
Predecessor equity	—	66.0
Common unitholders (34,608,183 and 24,661,754 units issued and outstanding, respectively)	415.5	429.0
Subordinated unitholders (0 and 3,571,429 convertible units issued and outstanding, respectively)	—	(54.6)
General partner unitholders	(5.9)	(4.8)
Accumulated other comprehensive loss	(31.9)	(40.5)
Total partners' equity	377.7	395.1
Noncontrolling interests	227.7	167.7
Total equity	605.4	562.8
Total liabilities and equity	$1,481.5	$1,419.7

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2009	2008	2007
	(Millions, except per unit amounts)		
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$456.3	$ 881.2	$ 807.9
Sales of natural gas, propane, NGLs and condensate to affiliates	456.7	791.5	568.6
Transportation, processing and other	79.2	59.9	40.7
Transportation, processing and other to affiliates	16.0	26.2	16.7
(Losses) gains from commodity derivative activity, net	(62.3)	75.4	(83.1)
Losses from commodity derivative activity, net — affiliates	(3.5)	(3.7)	(4.6)
Total operating revenues	942.4	1,830.5	1,346.2
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	529.5	1,218.0	1,005.2
Purchases of natural gas, propane and NGLs from affiliates	246.7	263.0	180.4
Operating and maintenance expense	69.7	77.4	59.3
Depreciation and amortization expense	64.9	53.2	40.2
General and administrative expense	11.9	13.1	15.9
General and administrative expense — affiliates	20.4	20.2	20.3
Other, net	—	(1.5)	—
Total operating costs and expenses	943.1	1,643.4	1,321.3
Operating (loss) income	(0.7)	187.1	24.9
Interest income	0.3	6.1	5.6
Interest expense	(28.3)	(32.8)	(25.7)
Earnings from unconsolidated affiliates	18.5	18.2	24.7
(Loss) income before income taxes	(10.2)	178.6	29.5
Income tax expense	(0.6)	(0.6)	(0.8)
Net (loss) income	(10.8)	178.0	28.7
Net income attributable to noncontrolling interests	(8.3)	(36.1)	(29.8)
Net (loss) income attributable to partners	(19.1)	141.9	(1.1)
Net loss (income) attributable to predecessor operations	1.0	(16.2)	(18.3)
General partner unitholders' interest in net income or net loss	(12.7)	(13.0)	(3.9)
Net (loss) income allocable to limited partners	$ (30.8)	$ 112.7	$ (23.3)
Net (loss) income per limited partner unit — basic and diluted	$ (0.99)	$ 4.11	$ (1.14)
Weighted-average limited partner units outstanding — basic and diluted	31.2	27.4	20.5

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2009	2008	2007
		(Millions)	
Net (loss) income	$(10.8)	$178.0	$ 28.7
Other comprehensive loss:			
Reclassification of cash flow hedge losses (gains) into earnings	20.6	7.5	(3.1)
Net unrealized losses on cash flow hedges	(12.0)	(33.1)	(19.1)
Total other comprehensive income (loss)	8.6	(25.6)	(22.2)
Total comprehensive (loss) income	(2.2)	152.4	6.5
Total comprehensive income attributable to noncontrolling interests	(8.3)	(36.1)	(29.8)
Total comprehensive (loss) income attributable to partners	$(10.5)	$116.3	$(23.3)

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Partners' Equity								
	Predecessor Equity	**Common Unitholders**	**Class C Unitholders**	**Class D Unitholders**	**Subordinated Unitholders**	**General Partner Unitholders**	**Accumulated Other Comprehensive Income (Loss)**	**Noncontrolling Interests**	**Total Equity**
					(Millions)				
Balance, January 1, 2009	$ 66.0	$ 429.0	$ —	$ —	$ (54.6)	$ (4.8)	$ (40.5)	$ 167.7	$ 562.8
Net change in parent advances	3.0	—	—	—	—	—	—	—	3.0
Conversion of subordinated units to common units	—	(52.1)	—	—	52.1	—	—	—	—
Distributions	—	(67.7)	—	(2.1)	(2.1)	(13.4)	—	(27.0)	(112.3)
Contributions from DCP Midstream, LLC	—	0.7	—	—	—	—	—	—	0.7
Contributions from noncontrolling interests	—	—	—	—	—	—	—	78.7	78.7
Other	—	(0.1)	—	—	—	—	—	—	(0.1)
Issuance of 2,875,000 common units	—	69.5	—	—	—	—	—	—	69.5
Issuance of 3,500,000 Class D units	—	—	—	49.7	—	—	—	—	49.7
Acquisition of additional 25.1% interest in East Texas and the NGL Hedge	(68.0)	—	—	4.6	—	—	—	—	(63.4)
Deficit purchase price over acquired assets	—	—	—	19.0	—	—	—	—	19.0
Conversion of Class D units into common units	—	66.8	—	(66.8)	—	—	—	—	—
Comprehensive income:									
Net loss attributable to predecessor operations	(1.0)	—	—	—	—	—	—	—	(1.0)
Net (loss) income	—	(30.6)	—	(4.4)	4.6	12.3	—	8.3	(9.8)
Reclassification of cash flow hedges into earnings	—	—	—	—	—	—	20.6	—	20.6
Net unrealized losses on cash flow hedges	—	—	—	—	—	—	(12.0)	—	(12.0)
Total comprehensive (loss) income	(1.0)	(30.6)	—	(4.4)	4.6	12.3	8.6	8.3	(2.2)
Balance, December 31, 2009	$ —	$ 415.5	$ —	$ —	$ —	$ (5.9)	$ (31.9)	$ 227.7	$ 605.4
Balance, January 1, 2007	$ 215.4	$ 223.4	$ (20.7)	$ —	$ (101.6)	$ (5.0)	$ 7.3	$ 101.7	$ 420.5
Net change in parent advances	(16.4)	—	—	—	—	—	—	—	(16.4)
Acquisition of East Texas, Discovery and the Swap	(153.3)	27.0	—	—	—	0.6	—	—	(125.7)
Excess purchase price over acquired assets	—	(118.0)	—	—	—	—	—	—	(118.0)
Acquisition of Momentum Energy Group, Inc.	—	12.0	—	—	—	—	—	22.8	34.8
Purchase of units	—	(0.3)	—	—	—	—	—	—	(0.3)
Issuance of units	—	0.3	—	—	—	—	—	—	0.3
Issuance of 5,386,732 common units	—	228.5	—	—	—	—	—	—	228.5
Conversion of Class C units to common units	—	(20.7)	20.7	—	—	—	—	—	—
Contributions	—	0.2	—	—	0.6	—	—	31.6	32.4
Distributions	—	(27.0)	(0.2)	—	(14.1)	(3.2)	—	(30.8)	(75.3)
Equity-based compensation	—	0.2	—	—	—	—	—	—	0.2
Comprehensive income:									
Net income attributable to predecessor operations	18.3	—	—	—	—	—	—	—	18.3
Net (loss) income	—	(16.8)	0.2	—	(5.0)	2.2	—	29.8	10.4
Reclassification of cash flow hedges into earnings	—	—	—	—	—	—	(3.1)	—	(3.1)
Net unrealized losses on cash flow hedges	—	—	—	—	—	—	(19.1)	—	(19.1)
Total comprehensive income (loss)	18.3	(16.8)	0.2	—	(5.0)	2.2	(22.2)	29.8	6.5
Balance, December 31, 2007	$ 64.0	$ 308.8	$ —	$ —	$ (120.1)	$ (5.4)	$ (14.9)	$ 155.1	$ 387.5
Net change in parent advances	(14.2)	—	—	—	—	—	—	—	(14.2)
Issuance of 4,250,000 common units	—	132.1	—	—	—	—	—	—	132.1
Conversion of subordinated units to common units	—	(66.4)	—	—	66.4	—	—	—	—
Contributions	—	4.0	—	—	—	—	—	21.3	25.3
Distributions	—	(53.9)	—	—	(10.5)	(11.3)	—	(46.4)	(122.1)
Equity-based compensation	—	0.2	—	—	—	—	—	—	0.2
Acquisition of subsidiaries	—	—	—	—	—	—	—	1.6	1.6
Comprehensive income:									
Net income attributable to predecessor operations	16.2	—	—	—	—	—	—	—	16.2
Net income	—	104.2	—	—	9.6	11.9	—	36.1	161.8
Reclassification of cash flow hedges into earnings	—	—	—	—	—	—	7.5	—	7.5
Net unrealized losses on cash flow hedges	—	—	—	—	—	—	(33.1)	—	(33.1)
Total comprehensive income (loss)	16.2	104.2	—	—	9.6	11.9	(25.6)	36.1	152.4
Balance, December 31, 2008	$ 66.0	$ 429.0	$ —	$ —	$ (54.6)	$ (4.8)	$ (40.5)	$ 167.7	$ 562.8

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2009	2008 (Millions)	2007
OPERATING ACTIVITIES:			
Net (loss) income	$ (10.8)	$ 178.0	$ 28.7
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	64.9	53.2	40.2
Earnings from unconsolidated affiliates	(18.5)	(18.2)	(24.7)
Distributions from unconsolidated affiliates	20.2	38.4	23.5
Other, net	(0.4)	(0.7)	(0.5)
Change in operating assets and liabilities which provided (used) cash, net of effects of acquisitions:			
Accounts receivable	(36.6)	101.4	(92.8)
Inventories	(13.3)	16.4	(7.2)
Net unrealized losses (gains) on derivative instruments	83.8	(101.0)	81.1
Accounts payable	21.5	(108.2)	49.1
Accrued interest	(0.6)	(0.3)	0.5
Other current assets and liabilities	(3.2)	19.0	(13.6)
Other long-term assets and liabilities	0.9	(0.4)	2.2
Net cash provided by operating activities	107.9	177.6	86.5
INVESTING ACTIVITIES:			
Capital expenditures	(164.8)	(72.7)	(45.6)
Acquisitions, net of cash acquired	(44.5)	(157.3)	(333.3)
Acquisition of unconsolidated affiliates	—	—	(153.3)
Investments in unconsolidated affiliates	(7.0)	(7.4)	(3.9)
Return of investment from unconsolidated affiliate	2.2	—	—
Payment of earnest deposit	—	—	(9.0)
Refund of earnest deposit	—	—	9.0
Proceeds from sales of assets	0.3	2.9	0.1
Purchases of available-for-sale securities	(1.1)	(608.2)	(6,921.6)
Proceeds from sales of available-for-sale securities	51.1	650.5	6,924.0
Net cash used in investing activities	(163.8)	(192.2)	(533.6)
FINANCING ACTIVITIES:			
Proceeds from debt	237.0	660.4	579.0
Payments of debt	(280.5)	(633.9)	(217.0)
Payment of deferred financing costs	—	—	(0.6)
Purchase of units	—	—	(0.3)
Proceeds from issuance of common units, net of offering costs	69.5	132.1	228.5
Excess purchase price over acquired assets	—	—	(100.3)
Net change in advances to predecessor from DCP Midstream, LLC	3.0	(14.2)	(16.4)
Distributions to unitholders and general partner	(85.3)	(76.2)	(44.0)
Distributions to noncontrolling interests	(27.0)	(46.4)	(30.8)
Contributions from noncontrolling interests	78.7	21.3	31.6
Contributions from DCP Midstream, LLC	0.7	4.1	0.5
Net cash (used in) provided by financing activities	(3.9)	47.2	430.2
Net change in cash and cash equivalents	(59.8)	32.6	(16.9)
Cash and cash equivalents, beginning of period	61.9	29.3	46.2
Cash and cash equivalents, end of period	$ 2.1	$ 61.9	$ 29.3

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, producing, transporting, storing and selling propane and transporting and selling NGLs and condensate.

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; our Southern Oklahoma system (acquired in May 2007); our limited liability company interest in Discovery Producer Services LLC, or Discovery (acquired in July 2007); our Wyoming system and a 70% interest in our Colorado system (each acquired in August 2007); our 50.1% interest in our East Texas system (acquired in July 2007 and April 2009); our Michigan systems (acquired in October 2008 and November 2009); our wholesale propane logistics business; and our NGL transportation pipelines.

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, and is wholly-owned by DCP Midstream, LLC. DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as 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 our assets. DCP Midstream, LLC owns approximately 35% of our partnership.

The consolidated financial statements include the accounts of the Company and all majority-owned subsidiaries where we have the ability to exercise control and undivided interests in jointly owned assets. 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, are accounted for using the equity method. Intercompany balances and transactions have been eliminated.

The consolidated financial statements include our accounts, which have been combined with the historical assets, liabilities and operations of our predecessor operations. Our predecessor operations consist of our initial 25% limited liability company interest in DCP East Texas Holdings, LLC, or East Texas and our 40% limited liability company interest in 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, and our additional 25.1% limited liability interest in East Texas, which we acquired from DCP Midstream, LLC in April 2009. Prior to our acquisition of an additional 25.1% limited liability company interest in East Texas we owned a 25.0% limited liability company interest in East Texas which we accounted for under the equity method of accounting. Subsequent to this transaction we own a 50.1% limited liability interest in East Texas, and account for East Texas as a consolidated subsidiary. These transactions were among entities under common control. We recognize transfers of net assets between entities under common control at DCP Midstream, LLC's basis in the net assets contributed. In addition, transfers of net assets 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; accordingly, our financial information includes the historical results of Discovery, the Swap and East Texas for all periods presented. The amount of the purchase price in excess of DCP Midstream, LLC's basis in the net assets, if any, is recognized as a reduction to partners' equity. The amount of the purchase price in deficit of DCP Midstream, LLC's basis in the net assets, if any, is recognized as an increase to partners' equity. In addition, the results of operations of our Southern Oklahoma, Wyoming and Colorado systems, and our Michigan systems, have been included in the consolidated financial statements since their respective acquisition dates.

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 the assets, liabilities and operations of East Texas, our equity interest in Discovery, and the Swap, prior to our acquisition from DCP Midstream, LLC, 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 unaffiliated entities. 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.

We adopted the amended guidance of the Financial Accounting Standards Board, or FASB, Accounting Standards Codification, or ASC, 810 "Consolidation," or ASC 810, effective January 1, 2009, which required us to retrospectively recast our financial statements for all periods presented. As a result of adoption, we have reclassified our noncontrolling interests on our balance sheets from a component of liabilities to a component of equity and have also reclassified the net income or net loss attributable to noncontrolling interests on our consolidated statements of operations, to below net income for all periods presented. Furthermore, we have displayed the portion of other comprehensive income that is attributable to noncontrolling interests within our statements of comprehensive income or loss. We also added a rollforward of the noncontrolling interest within our consolidated statements of changes in equity.

Certain amounts in the prior year's consolidated financial statements have been reclassified to the current year presentation.

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 consolidated financial statements and notes. Although these estimates are based on management's best available knowledge of current and expected future events, actual results could differ from those estimates.

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 — We may invest available cash balances in various financial instruments, such as commercial paper and money market instruments. 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 are used as collateral to secure the term loan portion of our credit facility and to finance gathering and compression asset acquisitions. 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 (loss), or AOCI. The cost, including accrued interest on investments, approximates fair value, due to the short-term, highly liquid nature of the securities held by us; interest rates are re-set on a daily, weekly or monthly basis.

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.

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

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 is determined using a risk free interest rate, and increases due to the passage of time based on the time value of money until the obligation is settled.

Goodwill and Intangible Assets — 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 when we believe events or changes in circumstances indicate that we may not be able to recover the carrying value of the reporting unit. 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, the excess of the carrying value over the fair value is recognized as an impairment loss.

Intangible assets consist primarily of customer contracts, including commodity purchase, transportation and processing contracts and related relationships. These intangible assets are amortized on a straight-line basis over the period of expected future benefit. Intangible assets are removed from the gross carrying amount and the total of accumulated amortization in the period in which they become fully amortized.

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 sum of the undiscounted 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 and discounted cash flow models. 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.

Investments in Unconsolidated Affiliates — We use the equity method to 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.

We evaluate our investments in unconsolidated affiliates for impairment whenever events or changes in circumstances indicate that the carrying value of such investments may have experienced a 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 investments in unconsolidated affiliates using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. If the estimated fair value is considered to be permanently less than the carrying value, the excess of the carrying value over the estimated fair value is recognized as an impairment loss.

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

Noncontrolling Interest — Noncontrolling interest represents any third party or affiliate interest in non-wholly owned entities that we consolidate. For financial reporting purposes, the assets and liabilities of these entities are consolidated with those of our own, with any third party or affiliate interest in our consolidated balance sheet amounts shown as noncontrolling interest in equity. Distributions to and contributions from noncontrolling interests represent cash payments to and cash contributions from, respectively, such third party and affiliate investors.

Accounting for Risk Management Activities and Financial Instruments — 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. The remaining non-trading derivatives, which are related to assets-based activities for which the normal purchases or normal sale exception are not elected, are recorded at fair value in the consolidated balance sheets as unrealized gains or unrealized losses in derivative instruments, with changes in the fair value recognized in the consolidated statements of operations. 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 gains and losses from commodity 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 gains and losses from commodity 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 derivative 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 derivative 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 derivative 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 the expected relationship 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. However, to the extent a sustained decline in commodity prices results in a decline in volumes, our revenues from these arrangements would be reduced.
- *Percent-of-proceeds arrangements* — Under percent-of-proceeds 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 percent-of-proceeds arrangements relate 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.
- *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, credit metrics, liquidity 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 not recognized until the cash 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 for non-trading commodity derivative activity net in the consolidated statements of operations as gains and losses from commodity derivative activity. These activities include mark-to-market gains and losses on energy trading contracts and the settlement of financial or physical energy trading contracts.

Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements with customers, producers or pipelines are recorded monthly as accounts receivable or accounts payable 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 and accounts receivable—affiliates were imbalances of $0.9 million and $4.9 million at December 31, 2009 and 2008, respectively. Included in the consolidated balance sheets as accounts payable—trade were imbalances of $1.4 million and $2.4 million at December 31, 2009 and 2008, respectively.

Significant Customers — There were no third party customers that accounted for more than 10% of total operating revenues for the years ended December 31, 2009, 2008 and 2007. There was one third party customer that accounted for approximately 12% 11% and 11% of total operating revenues for the years ended December 31, 2009, 2008 and 2007, respectively in our Wholesale Propane Logistics segment. We also had significant transactions with affiliates, and with suppliers of natural gas and propane.

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 December 31, 2009 and 2008, included in the consolidated balance sheets as other current liabilities amounted to $0.5 million and $1.3 million, respectively, and as other long-term liabilities amounted to $0.6 million and $0.6 million, respectively.

Equity-Based Compensation — Equity classified stock-based compensation cost is measured at fair value, based on the closing common unit price at grant date, and is recognized as expense over the vesting period. Liability classified stock-based compensation cost is remeasured at each reporting date at fair value, based on the closing common unit price, 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.

Allowance for Doubtful Accounts — Management estimates the amount of required allowances for the potential non-collectability of accounts receivable generally based upon the number of days past due, past collection experience and consideration of other relevant factors. However, past experience may not be indicative of future collections and therefore additional charges could be incurred in the future to reflect differences between estimated and actual collections.

Income Taxes — We are structured as a master limited partnership which is a pass-through entity for federal income tax purposes. Our income tax expense includes certain jurisdictions, including state, local, franchise and margin taxes of the master limited partnership and subsidiaries. We follow the asset and liability method of accounting for income taxes. Under this method, 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. Our taxable income or loss, which may vary substantially from the net income or loss reported in the consolidated statements of operations, is included in the federal returns of each partner.

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

3. Recent Accounting Pronouncements

On July 1, 2009, the FASB ASC became the source for authoritative U.S. Generally Accepted Accounting Principles, or GAAP, as noted in the discussion of Accounting Standards Update, or ASU, 2009-01 below. During the current quarter, the FASB issued several ASUs and ASCs. The following outlines the ASUs and ASCs that are applicable to us and may have an impact on our consolidated financial statements and related disclosures:

ASU 2010-06 "Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements," **or ASU 2010-06** — In January 2010, the FASB issued ASU 2010-06 which amended ASC topic 820-10 "Fair Value Measurement and Disclosures—Overall." ASU 2010-06 requires new disclosures regarding transfers in and out of assets and liabilities measured at fair value classified within the valuation hierarchy as either Level 1 or Level 2 and information about sales, issuances and settlements on a gross basis for assets and liabilities classified as Level 3. ASU 2010-06 clarifies existing disclosures on the level of disaggregation required and inputs and valuation techniques. The provisions of ASU 2010-06 are effective for us on January 1, 2010, except for disclosure of information about sales, issuances and settlements on a gross basis for assets and liabilities classified as Level 3, which is effective for us on January 1, 2011. The provisions of ASU 2010-06 impact only disclosures and we will disclose information in accordance with the revised provisions of ASU 2010-06 within all financial statements issued after the effective date of the ASU.

ASU 2010-02 "Consolidation (Topic 810): Accounting and Reporting for Decreases in Ownership of a Subsidiary—a Scope Clarification," **or ASU 2010-02** — In January 2010, the FASB issued ASU 2010-02 which amended ASC topic 810-10 "Consolidation—Overall." ASU 2010-02 clarifies guidance on the scope of the decrease in ownership provisions of ASC 810-10 and expands the disclosures about the deconsolidation of a subsidiary and the derecognition of a group of assets. ASU 2010-02 was effective for us on January 1, 2009. We have not had any transactions that would fall under the scope of the revised guidance of ASU 2010-02 and consequently there was no impact on our consolidated results of operations, cash flows and financial position as a result of adoption.

ASU 2009-17 "Consolidation (Topic 810): Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities," **or ASU 2009-17** — In December 2009, the FASB issued ASU 2009-17 which amended ASC topic 810 "Consolidation." ASU 2009-17 requires entities to perform additional analysis of their variable interest entities and consolidation methods. This SFAS became effective on January 1, 2010 and upon adoption we did not change our conclusions on which entities we consolidate in our financial statements.

ASU 2009-13 "Revenue Recognition (Topic 605) Multiple-Deliverable Revenue Arrangements," **or ASU 2009-13** — In October 2009, the FASB issued ASU 2009-13 which amended ASC Topic 605 "Revenue Recognition." The ASU addresses the accounting for multiple-deliverable arrangements, to enable vendors to account for products or services separately rather than as a combined unit. ASU 2009-13 is effective for us on January 1, 2011 and we are in the process of assessing the impact of ASU 2009-13 on our consolidated results of operations, cash flows and financial position as a result of adoption.

ASU 2009-05 "Fair Value Measurements and Disclosures (Topic 820) Measuring Liabilities at Fair Value," **or ASU 2009-05** — In August 2009, the FASB issued ASU 2009-05 which amended ASC Topic 820-10 "Fair Value Measurements and Disclosures—Overall" for the fair value measurement of liabilities. The amended provisions in this update are designed to reduce potential ambiguity in financial reporting when measuring the fair value of liabilities, helping to improve the consistency in the application of Topic 820 "Fair Value Measurements and Disclosures." ASU 2009-05 became effective on October 1, 2009 and there was no impact on our consolidated results of operations, cash flows or financial position as a result of adoption.

ASU 2009-01 "Topic 105—Generally Accepted Accounting Principles," **or ASU 2009-01** — In June 2009, the FASB issued ASU 2009-01, which amended ASC Topic 105 "Generally Accepted Accounting Principles," or ASC 105 which establishes the FASB ASC as the source of authoritative GAAP. The ASC supersedes all existing non-SEC accounting and reporting standards. We adopted the amended provisions of ASC 105 effective September 15, 2009, and have included all required disclosures in this filing. The amended provisions of ASC 105 impacts only disclosures so there was no effect on our consolidated results of operations, cash flows or financial position as a result of adoption.

ASC 260 "Earnings per Share," **or ASC 260** — In March 2008, the FASB amended guidance relating to earnings per share. The amendment seeks to improve the comparability of earnings per unit, or EPU, calculations for master limited partnerships with incentive distribution rights. We adopted these amended provisions effective January 1, 2009. As a result of adopting the amended provisions, undistributed earnings or losses are reduced or increased, respectively, by the amount of available cash that was generated during the current period, and undistributed earnings are no longer allocated to our general partner with respect to its incentive distribution rights, as our partnership agreement specifically limits incentive distributions to available cash. These amended provisions are applied retrospectively for all periods. We have retrospectively restated our previously disclosed net income (loss) per limited partner unit, or LPU, and related disclosures, within this filing. As a result of adoption, net income per LPU increased from $3.25 per unit to $4.11 per unit and net loss increased from $(1.05) per unit to $(1.14) per unit for the years ended December 31, 2008 and 2007, respectively.

ASC 320 "Investments—Debt and Equity Securities," **or ASC 320** — In April 2009, the FASB amended the other-than-temporary impairment guidance for debt securities to make the guidance more operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. We adopted these amended provisions effective June 30, 2009 and there was no impact on our consolidated results of operations, cash flows or financial position.

ASC 323 "Investments—Equity Method and Joint Ventures**," or ASC 323** — In November 2008, the FASB amended guidance on equity method investments. This issue addresses a) how the initial carrying value of an equity method investment should be determined; b) how impairment assessment of an underlying indefinite-lived intangible asset of an equity method investment should be performed; c) how an equity method investee's issuance of shares should be accounted for; and d) how to account for a change in an investment from the equity method to the cost method. This amendment became effective for us on January 1, 2009, and although it has not impacted the manner in which we apply equity method accounting for our current equity method investments, we will apply this guidance to future transactions with equity method investees.

***ASC 350 "Intangibles—Goodwill and Other,"* or ASC 350, *ASC 275 "Risks and Uncertainties,"* or ASC 275** — In April 2008, the FASB amended guidance relating to intangible assets and risks and uncertainties, for factors that should be considered in developing renewal or extension assumptions used to determine the useful life of an intangible asset. We adopted these amended provisions on January 1, 2009. As a result of acquisitions, we have intangible assets for customer contracts and related relationships in our consolidated balance sheets. Generally, costs to renew or extend such contracts are not significant, and are expensed to the consolidated statements of operations as incurred. During the year ended December 31, 2009, there were no contracts that were recognized as intangible assets that were renewed or extended.

ASC 805 "Business Combinations**," or ASC 805** — In April 2009, the FASB amended guidance relating to business combinations, providing additional guidance on the valuation of assets and liabilities assumed in a business combination that arise from contingencies, which would otherwise be subject to the provisions of other applicable GAAP. This amendment emphasizes that assets and liabilities assumed in a business combination that have an estimated fair value should be recorded at the time of acquisition. Assets and liabilities where the fair value may not be determinable during the measurement period will continue to be recognized pursuant to other applicable GAAP. This amendment was effective for us for business combinations with closing dates subsequent to January 1, 2009. We have accounted for business combinations with closing dates subsequent to the effective date in accordance with this new guidance.

In December 2007, the FASB amended guidance relating to business combinations, which requires the acquiring entity in a business combination subsequent to January 1, 2009 to recognize all (and only) the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. We adopted these amended provisions effective January 1, 2009, and have accounted for all transactions with closing dates subsequent to adoption in accordance with the revised provisions of this standard.

ASC 810 "Consolidation**," or ASC 810** — In December 2007, the FASB amended guidance relating to consolidation, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent's ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. These amended provisions also establish reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. We adopted these amended provisions effective January 1, 2009, which required retrospective restatement of our consolidated financial statements for all periods presented in this filing.

ASC 815 "Derivatives and Hedging**," or ASC 815** — In March 2008, the FASB amended guidance relating to derivatives and hedging to require disclosures of how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. We adopted these amended provisions effective January 1, 2009, and have included all required disclosures in this filing. The amended provisions impact only disclosures, so there was no effect on our consolidated results of operations, cash flows or financial position as a result of adoption.

ASC 820 "Fair Value Measurements and Disclosures**," or ASC 820** — In April 2009, the FASB amended guidance relating to fair value measurements and disclosures, which provides additional guidance on the valuation of assets or liabilities that are held in markets that have seen a significant decline in activity. While this amendment does not change the overall objective of determining fair value, it emphasizes that in markets with significantly decreased activity and the appearance of non-orderly transactions, an entity may employ multiple valuation techniques, to which significant adjustments may be required, to determine the most appropriate fair value. During 2009, certain of the markets in which we transact have seen a decrease in overall volume; however, we believe that these markets continue to provide sufficient liquidity such that transactions are executed in an orderly manner at fair value. We adopted these amended provisions effective June 30, 2009 and there was no impact on our consolidated results of operations, cash flows or financial position.

On January 1, 2008 we adopted the fair value measurement and disclosure requirements of ASC 820 for all financial assets and liabilities. Effective January 1, 2009, we adopted the fair value measurement and disclosure requirements for all nonfinancial assets and liabilities. There was no effect on our consolidated results of operations, cash flows, or financial position, and we have included all required disclosures as a result of the adoption of these requirements relative to nonfinancial assets and liabilities.

***ASC 825 "Financial Instruments,"* or ASC 825** — In April 2009, the FASB amended guidance relating to financial instruments, requiring disclosure of summarized financial information for financial instruments. We have instruments that are subject to the fair value disclosure requirements of ASC 825, and are subject to the amended provisions of this guidance. We adopted these amended provisions effective June 30, 2009 and there was no impact on our consolidated results of operations, cash flows or financial position.

4. Acquisitions

Gathering and Compression Assets

In November 2009, we acquired certain companies that held natural gas gathering and treating assets for $45.1 million from MichCon Pipeline Company, a subsidiary of DTE Energy. The assets are located in northern Michigan and are adjacent to our existing Michigan assets. These assets provide essential services for gas produced from the Antrim Shale formation. The results of the assets have been included prospectively, from the date of acquisition, as part of the Natural Gas Services segment. The fees under the Omnibus Agreement increased $0.1 million per year effective November 24, 2009 in connection with the acquisition. The purchase price allocation is as follows:

	(Millions)
Property, plant and equipment	$ 28.4
Intangible assets	16.1
Goodwill	3.0
Other liabilities	(2.4)
Total purchase price allocation	$ 45.1

In April 2009, we acquired an additional 25.1% interest in East Texas, and a fixed price natural gas liquids derivative by NGL component for the period of April 2009 to March 2010, or NGL Hedge, from DCP Midstream, LLC, for aggregate consideration of 3,500,000 Class D units, valued at $49.7 million. This transaction was among entities under common control. Our East Texas system includes a natural gas processing complex, an NGL fractionator and a gathering system. Transfers of net assets or exchanges of units 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. Accordingly, these consolidated financial statements include the historical results of East Texas for all periods presented. The NGL Hedge was entered into on the date of the transaction. Accordingly these financial statements include the results of the NGL Hedge prospectively from April 1, 2009. Prior to this transaction we owned a 25.0% limited liability company interest in East Texas, which we accounted for under the equity method of accounting. Subsequent to this transaction we own a 50.1% interest in East Texas, and account for East Texas as a consolidated subsidiary. The $19.0 million deficit purchase price, including purchase price adjustments for working capital of $0.7 million in the third quarter of 2009, under the historical basis of the net acquired assets was recorded as an increase in partners' equity, and the $49.7 million of Class D units issued as consideration for this transaction was recorded as an increase in partners' equity. The Class D units converted into our common units on a one-for-one basis on August 17, 2009. The holders of the Class D units received the second quarter distribution paid on August 14, 2009.

Combined Financial Information

The following table presents the impact on the consolidated balance sheet as of December 31, 2008, adjusted for the acquisition of an additional 25.1% interest in East Texas, from DCP Midstream, LLC.

	DCP Midstream Partners, LP (As previously reported) (a)	Consolidate East Texas (b)	Remove East Texas Equity Investment (c)	Combined DCP Midstream Partners, LP
		(Millions)		
ASSETS				
Current assets:				
Cash and cash equivalents	$ 48.0	$ 13.9	$ —	$ 61.9
Accounts receivable	80.4	35.9	—	116.3
Inventories	20.9	—	—	20.9
Other	15.9	0.4	—	16.3
Total current assets	165.2	50.2	—	215.4
Restricted investments	60.2	—	—	60.2
Property, plant and equipment, net	629.3	253.4	—	882.7
Goodwill and intangible assets, net	136.5	—	—	136.5
Investments in unconsolidated affiliates	175.4	—	(63.9)	111.5
Other non-current assets	13.4	—	—	13.4
Total assets	$ 1,180.0	$ 303.6	$ (63.9)	$ 1,419.7
LIABILITIES AND EQUITY				
Accounts payable and other current liabilities	$ 124.8	$ 38.4	$ —	$ 163.2
Long-term debt	656.5	—	—	656.5
Other long-term liabilities	34.9	2.3	—	37.2
Total liabilities	816.2	40.7	—	856.9
Commitments and contingent liabilities				
Equity:				
Partners' equity				
Net equity	369.6	129.9	(63.9)	435.6
Accumulated other comprehensive income	(40.5)	—	—	(40.5)
Total partners' equity	329.1	129.9	(63.9)	395.1
Noncontrolling interests	34.7	133.0	—	167.7
Total equity	363.8	262.9	(63.9)	562.8
Total liabilities and equity	$ 1,180.0	$ 303.6	$ (63.9)	$ 1,419.7

The following tables present the impact on the consolidated statements of operations, adjusted for the acquisition of an additional 25.1% interest in East Texas, from DCP Midstream, LLC, for the periods indicated.

Year Ended December 31, 2008

	DCP Midstream Partners, LP (As previously reported) (a)	Consolidate East Texas (b)	Remove East Texas Equity Earnings (c)	Combined DCP Midstream Partners, LP
		(Millions)		
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 1,156.3	$ 516.4	$ —	$ 1,672.7
Transportation, processing and other	57.2	28.9	—	86.1
Gains (losses) from commodity derivative activity, net	72.3	(0.6)	—	71.7
Total operating revenues	1,285.8	544.7	—	1,830.5
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	1,061.2	419.8	—	1,481.0
Operating and maintenance expense	43.0	34.4	—	77.4
Depreciation and amortization expense	36.5	16.7	—	53.2
General and administrative expense and other	22.5	9.3	—	31.8
Total operating costs and expenses	1,163.2	480.2	—	1,643.4
Operating income	122.6	64.5	—	187.1
Interest (expense) income, net	(27.2)	0.5	—	(26.7)
Earnings from unconsolidated affiliates	34.3	—	(16.1)	18.2
Income before income taxes	129.7	65.0	(16.1)	178.6
Income tax expense	(0.1)	(0.5)	—	(0.6)
Net income	129.6	64.5	(16.1)	178.0
Net income attributable to noncontrolling interests	(3.9)	(32.2)	—	(36.1)
Net income attributable to partners	$ 125.7	$ 32.3	$ (16.1)	$ 141.9

Year Ended December 31, 2007

	DCP Midstream Partners, LP (As previously reported) (a)	Consolidate East Texas (b)	Remove East Texas Equity Earnings (c)	Combined DCP Midstream Partners, LP
		(Millions)		
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 925.8	$ 450.7	$ —	$ 1,376.5
Transportation, processing and other	35.1	22.3	—	57.4
Losses from commodity derivative activity, net	(87.6)	(0.1)	—	(87.7)
Total operating revenues	873.3	472.9	—	1,346.2
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	826.7	358.9	—	1,185.6
Operating and maintenance expense	32.1	27.2	—	59.3
Depreciation and amortization expense	24.4	15.8	—	40.2
General and administrative expense and other	24.1	12.1	—	36.2
Total operating costs and expenses	907.3	414.0	—	1,321.3
Operating (loss) income	(34.0)	58.9	—	24.9
Interest (expense) income, net	(20.5)	0.4	—	(20.1)
Earnings from unconsolidated affiliates	39.3	—	(14.6)	24.7
(Loss) income before income taxes	(15.2)	59.3	(14.6)	29.5
Income tax expense	(0.1)	(0.7)	—	(0.8)
Net (loss) income	(15.3)	58.6	(14.6)	28.7
Net income attributable to noncontrolling interests	(0.5)	(29.3)	—	(29.8)
Net (loss) income attributable to partners	$ (15.8)	$ 29.3	$ (14.6)	$ (1.1)

(a) Amounts as previously reported with 25% of East Texas' results presented as earnings from unconsolidated affiliates.
(b) Adjustments to present East Texas on a consolidated basis at 100%, with noncontrolling interest of 49.9%.
(c) Adjustments to remove East Texas equity earnings at 25%.

The following table presents unaudited pro forma information for the consolidated statements of operations for the years ended December 31, 2009 and 2008, as if the acquisition of certain companies from MichCon Pipeline Company had occurred at the beginning of each year presented. Revenues of $1.1 million and net income attributable to partners of $0.5 million, associated with the acquired companies, from the date of acquisition through December 31, 2009 have been included in the Consolidated Statement of Operations.

	2009			2008		
	DCP Midstream Partners, LP	Acquisition of certain companies from MichCon Pipeline Company	DCP Midstream Partners, LP Pro Forma	DCP Midstream Partners, LP	Acquisition of certain companies from MichCon Pipeline Company	DCP Midstream Partners, LP Pro Forma
	(Millions, except per unit amounts)					
Total operating revenues	$ 942.4	$ 9.6	$ 952.0	$ 1,830.5	$ 12.1	$ 1,842.6
Net (loss) income attributable to partners	$ (19.1)	$ 2.2	$ (16.9)	$ 141.9	$ 3.8	$ 145.7
Less:						
Net loss (income) attributable to predecessor operations	1.0	—	1.0	(16.2)	—	(16.2)
General partner unitholders interest in net income	(12.7)	(0.1)	(12.8)	(13.0)	—	(13.0)
Net (loss) income allocable to limited partners	$ (30.8)	$ 2.1	$ (28.7)	$ 112.7	$ 3.8	$ 116.5
Net (loss) income per limited partner unit – basic and diluted	$ (0.99)	$ 0.07	$ (0.92)	$ 4.11	$ 0.14	$ 4.25

The pro forma information is not intended to reflect actual results that would have occurred if the companies had been combined during the periods presented, nor is it intended to be indicative of the results of operations that may be achieved by us in the future.

5. Agreements and Transactions with Affiliates

DCP Midstream, LLC

Omnibus Agreement and Other General and Administrative Charges

We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC.

Following is a summary of the fees we incurred under the Omnibus Agreement as well as other fees paid to DCP Midstream, LLC:

	Year Ended December 31, 2009	2008	2007
		(Millions)	
Omnibus Agreement	$ 9.7	$ 9.8	$ 7.9
Other fees — DCP Midstream, LLC	10.4	10.4	12.4
Total — DCP Midstream, LLC	$20.1	$20.2	$20.3

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, taxes and engineering.

In December 2009 we extended the omnibus agreement through December 31, 2010 for $9.8 million. The Omnibus Agreement also addresses the following matters:

- 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 derivative 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. On December 7, 2009 we received an investment grade credit rating from Standard & Poor's Ratings Group. DCP Midstream, LLC is no longer obligated to continue to maintain its credit support for our obligations related to derivative financial instruments, in effect as of December 7, 2005, subsequent to this date. As of December 31, 2009, DCP Midstream, LLC has continued to provide parental guarantees totaling $43.0 million in favor of certain counterparties to our commodity derivative instruments; 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).

East Texas incurs general and administrative expenses directly from DCP Midstream, LLC. During the years ended December 31, 2009, 2008 and 2007, East Texas incurred $8.5 million, $8.6 million and $10.3 million, respectively, for general and administrative expenses from DCP Midstream, LLC, which includes expenses for our predecessor operations.

Outside of the Omnibus Agreement and amounts incurred by East Texas, we incurred other fees with DCP Midstream, LLC, which includes expenses for our predecessor operations, of $1.9 million, $1.8 million and $2.1 million, respectively, for the years ended December 31, 2009, 2008 and 2007, respectively. These amounts include allocated expenses, including professional services, insurance and internal audit.

Competition

None of DCP Midstream, LLC, or 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

In connection with our acquisition of our wholesale propane logistics business, DCP Midstream, LLC agreed to indemnify us until October 31, 2010 if certain contractual matters result in a claim, and agreed to indemnify us indefinitely for breaches of the agreement. The indemnity obligation for breach of the representations and warranties is not effective until claims exceed in the aggregate $680,000 and is subject to a maximum liability of $6.8 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. We have not pursued indemnification under this agreement.

Other Agreements and Transactions with DCP Midstream, LLC

In conjunction with our acquisition of a 50.1% limited liability company interest in East Texas from DCP Midstream, LLC, we entered into agreements with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse East Texas for certain amounts of East Texas capital projects as defined in the Contribution Agreements. These reimbursements are for a period not to exceed three years from the respective acquisition dates. DCP Midstream, LLC made capital contributions to East Texas for capital projects of $67.5 million and $23.1 million for the years ended December 31, 2009 and 2008, respectively.

On February 11, 2009, our East Texas natural gas processing complex and natural gas delivery system known as the Carthage Hub, had been temporarily shut in following a fire that was caused by a third party underground pipeline outside of our property line that ruptured. We are actively pursuing full reimbursement of our costs and lost margin associated with the incident from the responsible third party. In the event we are not reimbursed by the responsible third party, we have insurance covering property damage, net of applicable deductibles. Following this incident, DCP Midstream, LLC has agreed to reimburse to us twenty five percent of any claims received as reimbursement of costs and lost margin, from the responsible third party or from insurance. DCP Midstream, LLC will pay seventy five percent of costs related to the incident as a result of this agreement.

On February 25, 2009, we entered into a Contribution Agreement with DCP Midstream, LLC, whereby DCP Midstream, LLC contributed an additional 25.1% interest in East Texas and the NGL Hedge to us in exchange for 3,500,000 Class D units, providing us with a 50.1% interest in East Texas. This transaction closed in April 2009. Subsequent to this transaction we consolidate our 50.1% interest in East Texas and consequently no longer account for East Texas as an unconsolidated affiliate. The Class D Units converted into the Partnership's Common Units on a one for one basis on August 17, 2009.

We sell a portion of our residue gas and NGLs to, purchase natural gas and other petroleum products from, and provide gathering and transportation services for, DCP Midstream, LLC. We anticipate continuing to purchase and sell commodities to DCP Midstream, LLC in the ordinary course of business. In addition, DCP Midstream, LLC conducts derivative activities on our behalf.

DCP Midstream, LLC owns certain assets and is party to certain contractual relationships around our Pelico system, which is part of our Natural Gas Services segment, 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 us and is able to take natural gas from the outlet of the Pelico system and market it downstream of Pelico. We purchase natural gas from DCP Midstream, LLC upstream of Pelico and transport it to Pelico under a firm transportation agreement with an affiliate. Our purchases from DCP Midstream, LLC are at DCP Midstream LLC's actual acquisition cost plus any transportation service charges. Volumes that exceed our on-system demand and volumes supplying an industrial end user are sold to DCP Midstream, LLC at an index-based price, less contractually agreed to marketing fees. Revenues associated with these activities are reported gross in our consolidated statements of operations as sales of natural gas, propane, NGLs and condensate to affiliates.

In addition, in our Natural Gas Services segment, we sell NGLs processed at certain of our plants, and sell condensate removed from the gas gathering systems that deliver to certain of our systems under contracts to a subsidiary of DCP Midstream, LLC equal to that subsidiary's net weighted-average sales price, adjusted for transportation, processing and other charges from the tailgate of the respective asset.

In our NGL Logistics segment, 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 and Wilbreeze pipelines, pursuant to fee-based rates that will be applied to the volumes transported. DCP Midstream, LLC is the sole shipper on these pipelines under the transportation agreements. We generally report revenues associated with these activities in the consolidated statements of operations as transportation, processing and other to affiliates.

In April 2009, we entered into a thirteen year contractual arrangement with DCP Midstream, LLC in which we pay DCP Midstream, LLC a fee for processing services associated with the gas we gather on our Lindsey system, which is part of our Natural Gas Services segment. We generally report fees associated with these activities in the consolidated statements of operations as purchases of natural gas, propane, NGLs and condensate from affiliates. In addition, as part of this arrangement, DCP Midstream, LLC pays us a fee for certain gathering services. We generally report revenues associated with these activities in the consolidated statements of operations as transportation, processing and other to affiliates.

In July 2008, DCP Midstream, LLC issued additional parental guarantees outside of the Omnibus Agreement, totaling $200.0 million, in favor of certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with those counterparties. These guarantees were reduced to $60.0 million as of December 31, 2009 to correspond with lower commodity prices and collateral requirements. We pay DCP Midstream, LLC interest of 0.5% per annum on these outstanding guarantees.

In conjunction with our acquisition of a 40% limited liability company interest in Discovery from DCP Midstream, LLC in July 2007, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will make capital contributions to us as reimbursement for certain Discovery capital projects, which were forecasted to be completed prior to our acquisition of a 40% limited liability company interest in Discovery. Pursuant to the letter agreement, DCP Midstream, LLC made capital contributions to us of $0.7 million, $3.8 million and $0.3 million during the years ended December 31 2009, 2008 and 2007, respectively to reimburse us for these capital projects, which were substantially completed during 2008.

DCP Midstream, LLC was a significant customer during the years ended December 31, 2009, 2008 and 2007.

Spectra Energy

We purchase a portion of our propane from and market propane on behalf of Spectra Energy. We anticipate continuing to purchase propane from and market propane on behalf of Spectra Energy in the ordinary course of business.

We entered into a propane supply agreement with Spectra Energy, effective May 1, 2008 and terminating April 30, 2014, which provides us propane supply at our marine terminal, which is included in our Wholesale Propane Logistics segment, for up to approximately 120 million gallons of propane annually. This contract replaces the supply provided under a contract with a third party that was terminated by us for supplier non-performance during the first quarter of 2008.

ConocoPhillips

We have multiple agreements whereby we provide a variety of services for ConocoPhillips and its affiliates. The agreements include fee-based and percent-of-proceeds gathering and processing arrangements, and 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 $0.6 million, $1.9 million and $2.9 million of capital reimbursements during the years ended December 31, 2009, 2008 and 2007, respectively.

Summary of Transactions with Affiliates

The following table summarizes the transactions with affiliates:

	Year Ended December 31,		
	2009	2008	2007
		(Millions)	
DCP Midstream, LLC:			
Sales of natural gas, propane, NGLs and condensate	$451.4	$760.1	$553.2
Transportation, processing and other	$ 7.5	$ 15.4	$ 6.0
Purchases of natural gas, propane and NGLs	$138.4	$175.4	$150.2
Losses from derivative activity, net	$ (3.5)	$ (3.7)	$ (4.6)
Operating and maintenance expense	$ —	$ —	$ 0.4
General and administrative expense	$ 20.1	$ 20.2	$ 20.3
Interest expense	$ 0.2	$ 0.4	$ —
Spectra Energy:			
Sales of natural gas, propane, NGLs and condensate	$ —	$ 0.3	$ 1.1
Transportation, processing and other	$ 0.3	$ 0.2	$ —
Purchases of natural gas, propane and NGLs	$ 95.2	$ 50.9	$ —
ConocoPhillips:			
Sales of natural gas, propane, NGLs and condensate	$ 5.3	$ 31.1	$ 14.3
Transportation, processing and other	$ 8.2	$ 10.6	$ 10.7
Purchases of natural gas, propane and NGLs	$ 12.7	$ 36.7	$ 30.2
General and administrative expense	$ 0.3	$ —	$ —
Unconsolidated affiliates			
Purchases of natural gas, propane and NGLs	$ 0.4	$ —	$ —

We had accounts receivable and accounts payable with affiliates as follows:

	December 31, 2009	December 31, 2008
	(Millions)	
DCP Midstream, LLC:		
Accounts receivable	$71.5	$51.0
Accounts payable	$24.4	$30.3
Unrealized gains on derivative instruments—current	$ 5.5	$ —
Unrealized losses on derivative instruments—current	$ (5.4)	$ (1.2)
Spectra Energy:		
Accounts receivable	$ 0.1	$ 4.0
Accounts payable	$16.6	$ 5.3
ConocoPhillips:		
Accounts receivable	$ 2.2	$ 2.5
Accounts payable	$ 2.1	$ 0.4

6. Property, Plant and Equipment

A summary of property, plant and equipment by classification is as follows:

	Depreciable Life	December 31, 2009	December 31, 2008
		(Millions)	
Gathering systems	15 — 30 Years	$ 683.0	$ 497.7
Processing plants	25 — 30 Years	427.4	383.2
Terminals	25 — 30 Years	28.9	28.5
Transportation	25 — 30 Years	217.2	216.6
Underground storage	20 — 50 Years	0.1	0.1
General plant	3 — 5 Years	15.2	13.9
Construction work in progress		21.8	73.9
Property, plant and equipment		1,393.6	1,213.9
Accumulated depreciation		(393.5)	(331.2)
Property, plant and equipment, net		$1,000.1	$ 882.7

The above amounts include accrued capital expenditures of $3.8 million and $17.4 million as of December 31, 2009 and 2008, respectively, which are included in other current liabilities in the consolidated balance sheets. Interest capitalized on construction projects in 2009, 2008 and 2007, was $1.3 million, $0.3 million and $0.2 million, respectively.

Depreciation expense was $62.3 million, $51.1 million and $39.1 million for the years ended December 31, 2009, 2008 and 2007, 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 $8.5 million at December 31, 2009 and 2008. Accretion expense for the years ended December 31, 2009, 2008 and 2007 was $0.3 million $0.4 million and $0.1 million, respectively.

We identified various assets as having an indeterminate life, for which there is no requirement to establish a fair value for future retirement obligations associated with such assets. These assets include certain pipelines, gathering systems and processing facilities. A liability for these asset retirement obligations will be recorded only if and when a future retirement obligation with a determinable life is identified. These assets have an indeterminate life because they are owned and will operate for an indeterminate future period when properly maintained. Additionally, if the portion of an owned plant containing asbestos were to be modified or dismantled, we would be legally required to remove the asbestos. We currently have no plans to take actions that would require the removal of the asbestos in these assets. Accordingly, the fair value of the asset retirement obligation related to this asbestos cannot be estimated and no obligation has been recorded.

7. Goodwill and Intangible Assets

The change in the carrying amount of goodwill is as follows:

	December 31,	
	2009	2008
	(Millions)	
Beginning of period	$88.8	$80.2
Acquisitions	3.3	8.6
End of period	$92.1	$88.8

Goodwill increased during 2009 by $3.0 million as a result of our acquisition of certain companies that held natural gas gathering and treating assets from MichCon Pipeline Company, and by $0.3 million for the final purchase price allocation of the Michigan Pipeline & Processing, LLC, or MPP acquisition. Goodwill increased during 2008 by $6.7 million as a result of the MPP acquisition, and by $1.9 million for the final purchase price allocation for the Momentum Energy Group, Inc., or MEG, acquisition.

We perform an annual goodwill impairment test, and update the test during interim periods when we believe events or changes in circumstances indicated that we may not be able to recover the carrying value of a reporting unit. 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 and estimated future cash flows. 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 tests indicated that our reporting unit's fair value exceeded its carrying or book value; therefore, we did not record any impairment charges during the years ended December 31, 2009, 2008 and 2007. The carrying value of goodwill as of December 31, 2009 and 2008 was $62.8 million and $59.5 million, respectively for our Natural Gas Services segment, and $29.3 million and $29.3 million, respectively, for our Wholesale Propane Logistics segment.

If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value.

Intangible assets consist of customer contracts, including commodity purchase, transportation and processing contracts, and related relationships. The gross carrying amount and accumulated amortization of these intangible assets are included in the accompanying consolidated balance sheets as intangible assets, net, and are as follows:

	December 31, 2009	December 31, 2008
	(Millions)	
Gross carrying amount	$66.2	$52.5
Accumulated amortization	(5.7)	(4.8)
Intangible assets, net	$60.5	$47.7

Intangible assets increased in 2009 by $16.1 million as a result of our acquisition of certain companies that held natural gas gathering and treating assets from MichCon Pipeline Company, partially offset by a decrease of $0.4 million for the final purchase price allocation of the MPP acquisition.

For the years ended December 31, 2009, 2008 and 2007, we recorded amortization expense of $2.6 million, $2.1 million and $1.1 million, respectively. As of December 31, 2009, the remaining amortization periods range from approximately less than one year to 25 years, with a weighted-average remaining period of approximately 20 years.

Estimated future amortization for these intangible assets is as follows:

	Estimated Future Amortization (Millions)
2010	$ 3.2
2011	3.2
2012	3.2
2013	3.2
2014	3.2
Thereafter	44.5
Total	$ 60.5

8. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

	Percentage of Ownership as of December 31, 2009 and 2008	Carrying Value as of December 31, 2009	Carrying Value as of December 31, 2008
		(Millions)	
Discovery Producer Services LLC	40%	$ 108.2	$ 105.0
Black Lake Pipe Line Company	45%	6.2	6.3
Other	50%	0.2	0.2
Total investments in unconsolidated affiliates		$ 114.6	$ 111.5

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of $37.6 million and $39.7 million at December 31, 2009 and 2008, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Discovery.

There was a deficit between the carrying amount of the investment and the underlying equity of Black Lake of $5.7 million and $6.0 million at December 31, 2009 and 2008, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Black Lake.

Earnings from investments in unconsolidated affiliates were as follows:

	Year Ended December 31,		
	2009	2008	2007
		(Millions)	
Discovery Producer Services LLC	$16.6	$17.4	$24.1
Black Lake Pipe Line Company and other	1.9	0.8	0.6
Total earnings from unconsolidated affiliates	$18.5	$18.2	$24.7

The following summarizes financial information of our investments in unconsolidated affiliates:

	Year Ended December 31,		
	2009	2008	2007
		(Millions)	
Statements of operations:			
Operating revenue	$168.1	$247.9	$266.7
Operating expenses	$127.2	$216.7	$220.6
Net income	$ 40.4	$ 35.3	$ 48.3

	December 31,	
	2009	2008
	(Millions)	
Balance sheet:		
Current assets	$ 41.8	$ 54.1
Long-term assets	383.8	392.9
Current liabilities	(17.4)	(46.0)
Long-term liabilities	(23.6)	(20.1)
Net assets	$384.6	$380.9

9. Fair Value Measurement

Determination of Fair Value

Below is a general description of our valuation methodologies for derivative financial assets and liabilities, as well as short-term and restricted investments, which are measured at fair value. Fair values are generally based upon quoted market prices, where available. If listed market prices or quotes are not available, we determine fair value based upon a market quote, adjusted by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. These adjustments result in a fair value for each asset or liability under an "exit price" methodology, in line with how we believe a marketplace participant would value that asset or liability. These adjustments may include amounts to reflect counterparty credit quality, the effect of our own creditworthiness, the time value of money and/or the liquidity of the market.

- Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. We record counterparty credit valuation adjustments on all derivatives that are in a net asset position as of the measurement date in accordance with our established counterparty credit policy, which takes into account any collateral margin that a counterparty may have posted with us as well as any letters of credit that they have provided.

- Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability position with each counterparty. This adjustment takes into account any credit enhancements, such as collateral margin we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement date.
- Liquidity valuation adjustments are necessary when we are not able to observe a recent market price for financial instruments that trade in less active markets for the fair value to reflect the cost of exiting the position. Exchange traded contracts are valued at market value without making any additional valuation adjustments and, therefore, no liquidity reserve is applied. For contracts other than exchange traded instruments, we mark our positions to the midpoint of the bid/ask spread, and record a liquidity reserve based upon our total net position. We believe that such practice results in the most reliable fair value measurement as viewed by a market participant.

We manage our derivative instruments on a portfolio basis and the valuation adjustments described above are calculated on this basis. We believe that the portfolio level approach represents the highest and best use for these assets as there are benefits inherent in naturally offsetting positions within the portfolio at any given time, and this approach is consistent with how a market participant would view and value the assets and liabilities. Although we take a portfolio approach to managing these assets/liabilities, in order to reflect the fair value of any one individual contract within the portfolio, we allocate all valuation adjustments down to the contract level, to the extent deemed necessary, based upon either the notional contract volume, or the contract value, whichever is more applicable.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other market participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 12 Risk Management and Hedging Activities.

Valuation Hierarchy

Our fair value measurements are grouped into a three-level valuation hierarchy. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows:

- Level 1 — inputs are unadjusted quoted prices for *identical* assets or liabilities in active markets.
- Level 2 — inputs include quoted prices for *similar* assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 — inputs are unobservable and considered significant to the fair value measurement.

A financial instrument's categorization within the hierarchy is based upon the input that requires the highest degree of judgment in the determination of the instrument's fair value. Following is a description of the valuation methodologies used as well as the general classification of such instruments pursuant to the hierarchy.

Commodity Derivative Assets and Liabilities

We enter into a variety of derivative financial instruments, which may include over-the-counter, or OTC, instruments, such as natural gas, crude oil or NGL contracts.

Within our Natural Gas Services segment we typically use OTC derivative contracts in order to mitigate a portion of our exposure to natural gas, NGL and condensate price changes. We also may enter into natural gas derivatives to lock in margin around our storage and transportation assets. These instruments are generally classified as Level 2. Depending upon market conditions and our strategy, we may enter into OTC derivative positions with a significant time horizon to maturity, and market prices for these OTC derivatives may only be readily observable for a portion of the duration of the instrument. In order to calculate the fair value of these instruments, readily observable market information is utilized to the extent that it is available; however, in the event that readily observable market data is not available, we may interpolate or extrapolate based upon observable data. In instances where we utilize an interpolated or extrapolated value, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 3.

Within our Wholesale Propane Logistics segment, we may enter into a variety of financial instruments to either secure sales or purchase prices, or capture a variety of market opportunities. Since financial instruments for NGLs tend to be counterparty and location specific, we primarily use the OTC derivative instrument markets, which are not as active and liquid as exchange traded instruments. Market quotes for such contracts may only be available for short dated positions (up to six months), and an active market itself may not exist beyond such time horizon. Contracts entered into with a relatively short time horizon for which prices are readily observable in the OTC market are generally classified within Level 2. Contracts with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, historical and future expected relationship of NGL prices to crude oil prices, the knowledge of expected supply sources coming on line, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.

Each instrument is assigned to a level within the hierarchy at the end of each financial quarter depending upon the extent to which the valuation inputs are observable. Generally, an instrument will move toward a level within the hierarchy that requires a lower degree of judgment as the time to maturity approaches, and as the markets in which the asset trades will likely become more liquid and prices more readily available in the market, thus reducing the need to rely upon our internally developed assumptions. However, the level of a given instrument may change, in either direction, depending upon market conditions and the availability of market observable data.

Interest Rate Derivative Assets and Liabilities

We use interest rate swap agreements as part of our overall capital strategy. These instruments effectively exchange a portion of our floating rate debt for fixed rate debt. The swaps are generally priced based upon a London Interbank Offered Rate, or LIBOR, instrument with similar duration, adjusted by the credit spread between our company and the LIBOR instrument. Given that a portion of the swap value is derived from the credit spread, which may be observed by comparing similar assets in the market, these instruments are classified within Level 2. Default risk on either side of the swap transaction is also considered in the valuation. We record counterparty credit and entity valuation adjustments in the valuation of our interest rate swaps; however, these reserves are not considered to be a significant input to the overall valuation.

Short-Term and Restricted Investments

We are required to post collateral to secure the term loan portion of our credit facility, and may elect to invest a portion of our available cash balances in various financial instruments such as commercial paper and money market instruments. The money market instruments are generally priced at acquisition cost, plus accreted interest at the stated rate, which approximates fair value, without any additional adjustments. Given that there is no observable exchange traded market for identical money market securities, we have classified these instruments within Level 2. Investments in commercial paper are priced using a yield curve for similarly rated instruments, and are classified within Level 2. As of December 31, 2009, nearly all of our short-term and restricted investments were held in the form of money market securities.

Nonfinancial Assets and Liabilities

We utilize fair value on a non-recurring basis to perform impairment tests as required on our property, plant and equipment, goodwill and intangible assets. Assets and liabilities acquired in business combinations are recorded at their fair value on the date of acquisition. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and would generally be classified within Level 3, in the event that we were required to measure and record such assets at fair value within our consolidated financial statements. Additionally, we use fair value to determine the inception value of our asset retirement obligations. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition, and would generally be classified within Level 3.

The following table presents the financial instruments carried at fair value as of December 31, 2009 and 2008, by consolidated balance sheet caption and by valuation hierarchy, as described above:

	December 31, 2009				December 31, 2008			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(Millions)							
Current assets:								
Short term investments (a)	$ —	$ 0.1	$ —	$ 0.1	$ —	$ —	$ —	$ —
Commodity derivatives (b)	$ —	$ 6.9	$ 0.4	$ 7.3	$ —	$ 15.1	$ 0.3	$ 15.4
Long-term assets:								
Restricted investments	$ —	$ 10.0	$ —	$ 10.0	$ —	$ 60.2	$ —	$ 60.2
Commodity derivatives (c)	$ —	$ 1.8	$ 0.2	$ 2.0	$ —	$ 6.9	$ 1.7	$ 8.6
Current liabilities (d):								
Commodity derivatives	$ —	$(20.3)	$ (0.8)	$ (21.1)	$ —	$ (1.2)	$ —	$ (1.2)
Interest rate derivatives	$ —	$(20.4)	$ —	$ (20.4)	$ —	$(16.5)	$ —	$ (16.5)
Long-term liabilities (e):								
Commodity derivatives	$ —	$(46.0)	$ (0.4)	$ (46.4)	$ —	$ (3.2)	$ —	$ (3.2)
Interest rate derivatives	$ —	$(11.6)	$ —	$ (11.6)	$ —	$(22.8)	$ —	$ (22.8)

(a) Included in other current assets in our consolidated balance sheets.
(b) Included in current unrealized gains on derivative instruments in our consolidated balance sheets.
(c) Included in long-term unrealized gains on derivative instruments in our consolidated balance sheets.
(d) Included in current unrealized losses on derivative instruments in our consolidated balance sheets.
(e) Included in long-term unrealized losses on derivative instruments in our consolidated balance sheets.

Changes in Level 3 Fair Value Measurements

The tables below illustrate a rollforward of the amounts included in our consolidated balance sheets for derivative financial instruments that we have classified within Level 3. The determination to classify a financial instrument within Level 3 is based upon the significance of the unobservable factors used in determining the overall fair value of the instrument. Since financial instruments classified as Level 3 typically include a combination of observable components (that is, components that are actively quoted and can be validated to external sources) and unobservable components, the gains and losses in the table below may include changes in fair value due in part to observable market factors, or changes to our assumptions on the unobservable components. Depending upon the information readily observable in the market, and/or the use of unobservable inputs, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. In the event that there is a movement to/from the classification of an instrument as Level 3, we have reflected such items in the table below within the “Transfers In/Out of Level 3” caption.

We manage our overall risk at the portfolio level, and in the execution of our strategy, we may use a combination of financial instruments, which may be classified within any level. Since Level 1 and Level 2 risk management instruments are not included in the rollforward below, the gains or losses in the table do not reflect the effect of our total risk management activities.

	Beginning Balance	Net Realized and Unrealized Gains (Losses) Included in Earnings	Transfers In/Out of Level 3 (a)	Purchases, Issuances and Settlements, Net	Ending Balance	Net Unrealized Gains (Losses) Still Held Included in Earnings (b)
			(Millions)			
Year Ended December 31, 2009:						
Commodity derivative instruments:						
Current assets	$ 0.3	$ 0.2	$ (0.1)	$ —	$ 0.4	$ 0.4
Long-term assets	$ 1.7	$ (1.5)	$ —	$ —	$ 0.2	$ (0.1)
Current liabilities	$ —	$ (3.9)	$ —	$ 3.1	$ (0.8)	$ (1.8)
Long-term liabilities	$ —	$ (0.4)	$ —	$ —	$ (0.4)	$ (0.4)
Year Ended December 31, 2008:						
Commodity derivative instruments:						
Current assets	$ 0.2	$ 0.8	$ —	$ (0.7)	$ 0.3	$ 0.3
Long-term assets	$ 1.5	$ 1.0	$ (0.8)	$ —	$ 1.7	$ 1.0
Current liabilities	$ (1.6)	$ (0.2)	$ —	$ 1.8	$ —	$ —
Long-term liabilities	$ (0.2)	$ 0.2	$ —	$ —	$ —	$ 0.2

(a) Amounts transferred in are reflected at the fair value as of the beginning of the period and amounts transferred out are reflected at fair value at the end of the period.

(b) Represents the amount of total gains or losses for the period, included in gains or losses from commodity derivative activity, net, attributable to change in unrealized gains (losses) relating to assets and liabilities classified as Level 3 that are still held at December 31, 2009 and 2008.

10. Estimated Fair Value of Financial Instruments

We have determined 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 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 derivative instruments are carried at fair value. The carrying and fair values of outstanding balances under our credit agreement are $613.0 million and $590.0 million as of December 31, 2009 and $656.5 million and $656.5 million, respectively as of December 31, 2008. We determine the fair value of our credit facility borrowings based upon the discounted present value of expected future cash flows, taking into account the difference between the contractual borrowing spread and the spread for similar credit facilities available in the marketplace. Additionally, we have executed interest rate swap agreements on a portion of our interest rate exposure which swaps variable for fixed interest rates.

11. Debt

Long-term debt was as follows:

	Principal Amount 2009	2008
	(Millions)	
Revolving credit facility, weighted-average variable interest rate of 0.69% and 2.08%, respectively, and net effective interest rate of 4.41% and 4.48%, respectively, due June 21, 2012 (a)	$603.0	$596.5
Term loan facility, variable interest rate 0.34% and 1.54%, respectively, due June 21, 2012 (b)	10.0	60.0
Total long-term debt	$613.0	$656.5

(a) $575.0 million of debt has been swapped to a fixed rate obligation with effective fixed rates ranging from 2.26% to 5.19%, for a net effective rate of 4.41% on the $603.0 million of outstanding debt under our revolving credit facility as of December 31, 2009.

(b) The term loan facility is fully secured by restricted investments.

Credit Agreement

We have an $824.6 million 5-year credit agreement that matures June 21, 2012, or the Credit Agreement, which consists of:

- a $814.6 million revolving credit facility; and
- a $10.0 million term loan facility.

At December 31, 2009 and 2008, we had $0.3 million letters of credit issued under the credit agreement outstanding. Outstanding balances under the term loan facility are fully collateralized by investments in high-grade securities, which are classified as restricted investments in the accompanying consolidated balance sheet as of December 31, 2009 and 2008. As of December 31, 2009, the available capacity under the revolving credit facility was $211.9 million, which is net of non-participation by Lehman Brothers Commercial Bank, or Lehman Brothers. We incurred $0.6 million of debt issuance costs during 2007 associated with the Credit Agreement. These expenses are deferred as other long-term assets in the consolidated balance sheet and will be amortized over the term of the Credit Agreement.

Under the 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 credit rating. The revolving credit facility incurs an annual facility fee of 0.07% to 0.175% depending on our credit 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 Credit Agreement requires us to maintain a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Credit Agreement) of not more than 5.0 to 1.0, 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 5.5 to 1.0. Prior to our credit rating that we received on December 7, 2009 from Standard & Poor's Ratings Group, the Credit Agreement also required us to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, in each case as is defined by the Credit 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. As a result of our credit rating, we are no longer required to maintain this interest coverage ratio.

Our borrowing capacity may be limited by the Credit Agreement's financial covenant requirements. Except in the case of a default, amounts borrowed under our credit facility will not mature prior to the June 21, 2012 maturity date.

Other Agreements

As of December 31, 2009, we had an outstanding letter of credit with a counterparty to our commodity derivative instruments of $10.0 million, which reduces the amount of cash we may be required to post as collateral. We pay a fee of 0.75% per annum on this letter of credit. This letter of credit was issued directly by a financial institution and does not reduce the available capacity under our credit facility.

12. Risk Management and Hedging Activities

Our day to day operations expose us to a variety of risks including but not limited to changes in the prices of commodities that we buy or sell, changes in interest rates, and the creditworthiness of each of our counterparties. We manage certain of these exposures with both physical and financial transactions. We have established a comprehensive risk management policy, or Risk Management Policy, and a risk management committee, or the Risk Management Committee, to monitor and manage market risks associated with commodity prices and counterparty credit. The Risk Management Committee is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. The following briefly describes each of the risks that we manage.

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, sales and storage activities. For gathering and processing services, we may receive fees or commodities as payment for these services, depending on the contract type. We enter into derivative financial instruments to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices associated with our gathering, processing and sales activities, thereby stabilizing our cash flows. We have mitigated a portion of our expected commodity price risk associated with our gathering, processing and sales activities through 2014 with natural gas, crude oil and NGL derivative instruments. Additionally, given the limited depth of the NGL derivatives market, we primarily utilize crude oil swaps and following our acquisition of the NGL Hedge on April 1, 2009, to a limited extent NGL derivatives to mitigate a portion of our commodity price exposure for propane and heavier NGLs. Historically, prices of NGLs have been generally related to the price of crude oil, with some exceptions, notably in late 2008 to early 2009, when NGL pricing was at a greater discount to crude oil. Given the relationship and the lack of liquidity in the NGL financial market, we have historically used crude oil swaps to mitigate a portion of NGL price risks. When the relationship of NGL prices to crude oil prices is outside of historical ranges, we experience additional exposure as a result of the relationship. These transactions are primarily accomplished through the use of forward contracts, which are swap futures that effectively exchange our floating rate price risk for a fixed rate. However, the type of instrument that we use to mitigate a portion of our risk may vary depending upon our risk management objective. These transactions are not designated as hedging instruments for accounting purposes and the change in fair value is reflected within our consolidated statements of operations as a gain or a loss on commodity derivative activity.

With respect to our Pelico system, we may enter into financial derivatives to lock in transportation margins across the system, or to lock in margins around our leased storage facility to maximize value. This objective may be achieved through the use of physical purchases or sales of gas that are accounted for under accrual accounting. While the physical purchase or sale of gas transactions are accounted for under accrual accounting and any inventory is stated at lower of cost or market, the swaps are not designated as hedging instruments for accounting purposes and any change in fair value of these instruments is reflected within our consolidated statements of operations.

Our Wholesale Propane Logistics segment 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 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. However, 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. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. While the majority of our sales and purchases in this segment are index-based, 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. In such cases, we may manage this risk with derivatives that 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 transactions are not designated as hedging instruments for accounting purposes and the change in value is reflected in the current period within our consolidated statements of operations as a gain or loss on commodity derivative activity.

Our portfolio of commodity derivative activity is primarily accounted for using the mark-to-market method of accounting; however, depending upon our risk profile and objectives, in certain limited cases, we may execute transactions that qualify for the hedge method of accounting. Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for derivatives that manage our commodity price risk. We have used the mark-to-market method of accounting for all derivatives that manage our commodity price risk since July 2007, thus changes in fair value are recorded directly to the consolidated statements of operations. Derivative contracts that were put in place prior to this date may have been designated as cash flow or fair value hedges, and are described below.

Commodity Cash Flow Hedges — We used NGL, natural gas and crude oil swaps to mitigate a portion of the risk of market fluctuations in the price of NGLs, natural gas and condensate. Prior to July 1, 2007, the effective portion of the change in fair value of a derivative designated as a cash flow hedge was recorded in accumulated other comprehensive income, or AOCI. During the period in which the hedged transaction impacted earnings, amounts in AOCI associated with the hedged transaction were reclassified to the consolidated statements of operations in the same accounts as the item being hedged.

Given our election to discontinue using the hedge method of accounting, the remaining net loss deferred in AOCI relative to these cash flow hedges will be reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the underlying transactions impact earnings. Subsequent to July 1, 2007, the changes in fair value of financial derivatives are included in gains and losses from commodity derivative activity in the consolidated statements of operations.

Commodity Fair Value Hedges — Historically, we used fair value hedges to mitigate a portion of 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. As described above relative to our Wholesale Propane Logistics segment, we may have hedged producer price locks, or fixed price gas purchases, to reduce our cash flow exposure to fixed price risk by swapping the fixed price risk for a floating price position linked to the New York Mercantile Exchange or an index-based position.

Interest Rate Risk

Interest Rate Cash Flow Hedges — 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. These interest rate swap agreements convert the interest rate associated with an aggregate of $575.0 million of the indebtedness outstanding under our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. All 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 and are reclassified into earnings as the hedged transactions impact earnings. The effect that these swaps have on our consolidated financial statements, as well as the effect that is expected over the upcoming 12 months is summarized in the charts below. 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. $425.0 million of the agreements reprice prospectively approximately every 90 days and the remaining $150.0 million of the agreements reprice prospectively approximately every 30 days. Under the terms of the interest rate swap agreements, we pay fixed rates ranging from 2.26% to 5.19%, and receive interest payments based on the three-month and one-month LIBOR. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense.

Contingent Credit Features

Each of the above risks is managed through the execution of individual contracts with a variety of counterparties. Certain of our derivative contracts may contain credit-risk related contingent provisions that may require us to take certain actions in certain circumstances.

We have International Swap Dealers Association, or ISDA, contracts which are standardized master legal arrangements that establish key terms and conditions which govern certain derivative transactions. These ISDA contracts contain standard credit-risk related contingent provisions. Some of the provisions we are subject to are outlined below.

- If we were to have an effective event of default under our credit agreement that occurs and is continuing, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative liability positions.
- In the event that DCP Midstream, LLC was to be downgraded below investment grade by at least one of the major credit rating agencies, certain of our ISDA counterparties may have the right to reduce our collateral threshold to zero, potentially requiring us to fully collateralize any commodity contracts in a net liability position.
- Additionally, in some cases, our ISDA contracts contain cross-default provisions that could constitute a credit-risk related contingent feature. These provisions apply if we default in making timely payments under those agreements and the amount of the default is above certain predefined thresholds, which are significantly high and are generally consistent with the terms of our credit agreement. As of December 31, 2009, we are not a party to any agreements that would be subject to these provisions other than our credit agreement.

Our commodity derivative contracts that are not governed by ISDA contracts do not have any credit-risk related contingent features.

Depending upon the movement of commodity prices and interest rates, each of our individual contracts with counterparties to our commodity derivative instruments or to our interest rate swap instruments are in either a net asset or net liability position.

As of December 31, 2009, we had $62.1 million of individual commodity derivative contracts that contain credit-risk related contingent features that were in a net liability position, and have not posted any cash collateral relative to such positions. If a credit-risk related event were to occur and we were required to net settle our position with an individual counterparty, our ISDA contracts permit us to net all outstanding contracts with that counterparty, whether in a net asset or net liability position, as well as any cash collateral already posted. As of December 31, 2009 if a credit-risk related event were to occur we may be required to post additional collateral. Additionally, although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of December 31, 2009, if a credit-risk related event were to occur, the net liability position would be partially offset by contracts in a net asset position reducing our net liability to $58.3 million.

As of December 31, 2009 our interest rate swaps were in a net liability position of approximately $32.0 million, of which, the entire amount is subject to credit-risk related contingent features. If we were to have a default of any of our covenants to our credit agreement, that occurs and is continuing, the counterparties to our swap instruments may have the right to request that we net settle the instrument in the form of cash.

Collateral

As of December 31, 2009, we had an outstanding letter of credit with a counterparty to our commodity derivative instruments of $10.0 million and DCP Midstream, LLC had issued and outstanding parental guarantees totaling $103.0 million in favor of certain counterparties to our commodity derivative instruments. This letter of credit and parental guarantees reduce the amount of cash we may be required to post as collateral. As of December 31, 2009, we had no cash collateral posted with counterparties to our commodity derivative instruments.

Summarized Derivative Information

The following summarizes the balance within AOCI relative to our commodity and interest rate cash flow hedges:

	December 31, 2009	December 31, 2008
	(Millions)	
Commodity cash flow hedges:		
Net deferred losses in AOCI	$ (0.8)	$ (1.8)
Interest rate cash flow hedges:		
Net deferred losses in AOCI	(31.1)	(38.7)
Total AOCI	$ (31.9)	$ (40.5)

The fair value of our derivative instruments that are designated as hedging instruments, those that are marked to market each period, as well as the location of each within our consolidated balance sheets, by major category, is summarized as follows:

Balance Sheet Line Item	December 31, 2009	December 31, 2008	Balance Sheet Line Item	December 31, 2009	December 31, 2008
	(Millions)			(Millions)	
Derivative Assets Designated as Hedging Instruments:			**Derivative Liabilities Designated as Hedging Instruments:**		
Interest rate derivatives:			**Interest rate derivatives:**		
Unrealized gains on derivative instruments – current	$ —	$ —	Unrealized losses on derivative instruments – current	$ (20.4)	$ (16.5)
Unrealized gains on derivative instruments – long term	—	—	Unrealized losses on derivative instruments – long term	(11.6)	(22.8)
	$ —	$ —		$ (32.0)	$ (39.3)
Derivative Assets Not Designated as Hedging Instruments:			**Derivative Liabilities Not Designated as Hedging Instruments:**		
Commodity derivatives:			**Commodity derivatives:**		
Unrealized gains on derivative instruments – current	$ 7.3	$ 15.4	Unrealized losses on derivative instruments – current	$ (21.1)	$ (1.2)
Unrealized gains on derivative instruments – long term	2.0	8.6	Unrealized losses on derivative instruments – long term	(46.4)	(3.2)
	$ 9.3	$ 24.0		$ (67.5)	$ (4.4)

The following tables summarize the impact on our consolidated balance sheet and consolidated statements of operations of our derivative instruments that are accounted for using the cash flow hedge method of accounting.

	Gain (Loss) Recognized in AOCI on Derivatives — Effective Portion		Gain (Loss) Reclassified From AOCI to Earnings — Effective Portion		Gain (Loss) Recognized in Income on Derivatives — Ineffective Portion and Amount Excluded From Effectiveness Testing		Deferred Losses in AOCI Expected to be Reclassified into Earnings Over the Next 12 Months
	2009	2008	2009	2008	2009	2008	
	(Millions)		(Millions)		(Millions)		(Millions)
Interest rate derivatives	$(12.0)	$(33.1)	$(19.7)	$(6.7)(a)	$ —	$ — (a)(c)	$ (19.5)
Commodity derivatives	$ —	$ —	$ (0.9)	$(0.8)(b)	$ —	$ — (b)(c)	$ (0.5)

(a) Included in interest expense in our consolidated statements of operations.
(b) Included in sales of natural gas, propane, NGLs and condensate in our consolidated statements of operations.
(c) For the year ended December 31, 2009, 2008 and 2007, 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.

Changes in value of derivative instruments, for which the hedge method of accounting has not been elected from one period to the next, are recorded in the consolidated statements of operations. The following summarizes these amounts and the location within the consolidated statements of operations that such amounts are reflected:

Commodity Derivatives: Statements of Operations Line Item	Year Ended December 31, 2009	2008 (Millions)	2007
Third party:			
Realized	$ 16.8	$ (25.5)	$ (4.2)
Unrealized	(79.1)	100.9	(78.9)
(Losses) gains from commodity derivative activity, net	$(62.3)	$ 75.4	$(83.1)
Affiliates:			
Realized	$ (0.2)	$ (5.2)	$ (1.8)
Unrealized	(3.3)	1.5	(2.8)
Losses from commodity derivative activity, net — affiliates	$ (3.5)	$ (3.7)	$ (4.6)

We do not have any derivative financial instruments that qualify as a hedge of a net investment.

The following table represents, by commodity type, our net long or short positions that are expected to partially or entirely settle in each respective year. To the extent that we have long dated derivative positions that span multiple calendar years, the contract will appear in more than one line item in the table below.

	December 31, 2009		
Year of Expiration	Crude Oil Net Long (Short) Position (Bbls)	Natural Gas Net Long (Short) position (MMbtu)	Natural Gas Liquids Net Long (Short) Position (Bbls)
2010	(950,225)	(1,883,500)	(74,001)
2011	(949,000)	(1,496,500)	—
2012	(777,750)	(1,500,600)	—
2013	(748,250)	(730,000)	—
2014	(365,000)	—	—

We periodically enter into interest rate swap agreements to mitigate a portion of our floating rate interest exposure. As of December 31, 2009 we have swaps with a notional value between $25.0 million and $150.0 million, which, in aggregate, exchange $575.0 million of our floating rate obligation to a fixed rate obligation through June 2012.

13. 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 November 2009, we issued 2,500,000 common limited partner units at $25.40 per unit, and in December 2009 we issued an additional 375,000 common limited partner units to the underwriters who exercised their overallotment option. We received proceeds of $69.5 million, net of offering costs.

In April 2009, we issued 3,500,000 Class D units valued at $49.7 million. The Class D units were issued to DCP LP Holdings, LP and DCP Midstream GP, LP in consideration for an additional 25.1% interest in East Texas and the NGL Hedge. The Class D units converted into our common units on a one-for-one basis on August 17, 2009.

In March 2008, we issued 4,250,000 common limited partner units at $32.44 per unit, and received proceeds of $132.1 million, net of offering costs.

In January 2008, our registration statement on Form S-3 to register the 3,005,780 common limited partner units represented in the June 2007 private placement agreement and the 2,380,952 common limited partner units represented in the August 2007 private placement agreement was declared effective by the SEC.

In November 2007, our universal shelf registration statement on Form S-3 was declared effective by the SEC. The universal shelf registration statement has a maximum aggregate offering price of $1.5 billion, which will allow us to register and issue additional partnership units and debt obligations.

In August 2007, we issued 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 $100.0 million in the aggregate.

In July 2007, we issued 620,404 common units to DCP Midstream, LLC as partial consideration for the purchase of Discovery, East Texas and the Swap. In August 2007, we issued 275,735 common units to DCP Midstream, LLC as partial consideration for the purchase of certain subsidiaries of MEG.

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.

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; and
  - 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 — The general partner is entitled to a percentage of all quarterly distributions equal to its general partner interest of approximately 1% and limited partner interest of 1% as of December 31, 2009. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest.

The 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. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest level. The general partner's incentive distribution rights were not reduced as a result of our common limited partner unit issuances, 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 current general partner interest. Please read the *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 D Units — All of the Class D units were held by DCP Midstream, LLC and converted into our common units on a one for one basis on August 17, 2009. The holders of the Class D units received the second quarter distribution paid on August 14, 2009.

Class C Units — On July 2, 2007, the Class C units were converted to common units.

Subordinated Units — All of our subordinated units were held by DCP Midstream, LLC. The subordination period had an early termination provision that permitted 50% of the subordinated units, or 3,571,428 units, to convert into common units on a one-to-one basis in February 2008 and permitted the other 50% of the subordinated units, or 3,571,429 units, to convert into common units on a one-to-one basis in February 2009, following the satisfactory completion of the tests for ending the subordination period contained in our partnership agreement. The board of directors of the General Partner certified that all conditions for early conversion were satisfied.

Our partnership agreement provides that, during the subordination period, the common units had 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 were not entitled to receive any distributions until the common units received the Minimum Quarterly Distribution plus any arrearages from prior quarters. Furthermore, no arrearages could 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.

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, which ended in February 2009, 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 2009, 2008 and 2007:

Payment Date	Per Unit Distribution	Total Cash Distribution (Millions)
November 13, 2009	$ 0.600	$ 22.6
August 14, 2009	0.600	22.6
May 15, 2009	0.600	20.1
February 13, 2009	0.600	20.1
November 14, 2008	0.600	20.1
August 14, 2008	0.600	20.1
May 15, 2008	0.590	19.6
February 14, 2008	0.570	15.7
November 14, 2007	0.550	14.7
August 14, 2007	0.530	12.4
May 15, 2007	0.465	8.6
February 14, 2007	0.430	7.8

14. Equity-Based Compensation

Total compensation cost (credit) for equity-based arrangements was as follows:

	Year Ended December 31,		
	2009	2008	2007
		(Millions)	
Performance Units	$ 1.2	$ (0.7)	$ 1.1
Phantom Units	0.4	(0.4)	0.6
Restricted Phantom Units	0.6	0.1	—
Total compensation (credit) cost	$ 2.2	$ (1.0)	$ 1.7

On November 28, 2005, the board of directors of our General Partner adopted a long-term incentive plan, or LTIP, for employees, consultants and directors of our General Partner and its affiliates who perform services for us. 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 dividend equivalent rights, or DERs. Subject to adjustment for certain events, an aggregate of 850,000 LPUs may be delivered pursuant to awards under the LTIP. Awards that are canceled or 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. All awards are subject to cliff vesting, with the exception of the Phantom Units issued to directors in conjunction with our initial public offering, which are subject to graded vesting provisions.

All awards are accounted for as liability awards.

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 200% 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 our General Partner. The DERs are paid in cash at the end of the performance period. Of the remaining Performance Units outstanding at December 31, 2009, 6,535 units are expected to vest on December 31, 2010 and 36,715 units are expected to vest on December 31, 2011.

At December 31, 2009, there was approximately $0.8 million of unrecognized compensation expense related to the Performance Units that is expected to be recognized over a weighted-average period of 1.9 years. The following table presents information related to the Performance Units:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at January 1, 2007	23,090	$ 26.96	
Granted	29,610	$ 37.29	
Forfeited	(5,740)	$ 31.39	
Outstanding at December 31, 2007	46,960	$ 32.93	
Granted	17,085	$ 33.85	
Forfeited	(12,025)	$ 32.42	
Outstanding at December 31, 2008	52,020	$ 33.35	
Granted	52,450	$ 10.05	
Vested	(37,330)	$ 34.51	
Outstanding at December 31, 2009	67,140	$ 14.50	$ 29.57
Expected to vest (a)	43,250	$ 13.65	$ 29.57

(a) Based on our December 31, 2009 estimated achievement of specified performance targets, the performance estimate for units granted in 2009 is 100%, and for units granted in 2008 is 50%. The estimated forfeiture rate for units granted in 2009 is 30% and for units granted in 2008 is 23%.

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.

The following table presents the fair value of units vested and the unit-based liabilities paid for unit based awards related to Performance Units, including the related DERs:

	Units	Fair Value of Units Vested	Unit-Based Liabilities Paid
		(Millions)	
Vested in 2009 (a)	37,330	$ 1.1	$ 0.3

(a) 22,860 of the units and the related DERs that vested in 2009 will be paid in 2010.

Phantom Units — In conjunction with our initial public offering, in January 2006 our 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.

In 2009, we granted 16,000 Phantom Units, pursuant to the LTIP, to directors who are not officers or employees of affiliates of the General Partner as part of their annual director fees for 2009. All of these units vested during 2009.

In 2008, we granted 4,000 Phantom Units, pursuant to the LTIP, to directors who are not officers or employees of affiliates of the General Partner as part of their annual director fees for 2008. All of these units vested during 2008.

In 2007, we granted 4,500 Phantom Units, pursuant to 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. Of these units, 4,000 units vested during 2007 and 500 units vested in February 2008.

The DERs are paid quarterly in arrears.

The following table presents information related to the Phantom Units:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at January 1, 2007	24,700	$ 24.05	
Granted	4,500	$ 42.90	
Forfeited	(2,333)	$ 24.05	
Vested	(6,668)	$ 35.23	
Outstanding at December 31, 2007	20,199	$ 24.56	
Granted	4,000	$ 35.88	
Forfeited	(4,000)	$ 24.05	
Vested	(6,501)	$ 32.91	
Outstanding at December 31, 2008	13,698	$ 24.05	
Granted	16,000	$ 10.05	
Vested	(29,698)	$ 16.51	
Outstanding at December 31, 2009	—	$ —	$ —

The following table presents the fair value of units vested and the unit-based liabilities paid for unit based awards related to Phantom Units:

	Units	Fair Value of Units Vested	Unit-Based Liabilities Paid
		(Millions)	
Vested in 2007	6,668	$ 0.2	$ 0.2
Vested in 2008	6,501	$ 0.2	$ 0.2
Vested in 2009	29,698	$ 0.5	$ 0.5

Restricted Phantom Units — Our General Partner's board of directors awarded restricted phantom LPUs, or RPUs, to key employees under the LTIP. The RPUs outstanding at December 31, 2009 are expected to vest on December 31, 2011. The DERs are paid quarterly in arrears.

At December 31, 2009, there was approximately $0.9 million of unrecognized compensation expense related to the RPUs that is expected to be recognized over a weighted-average period of 1.7 years. The following table presents information related to the RPUs:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at January 1, 2008	—	$ —	
Granted	17,085	$ 33.85	
Forfeited	(2,395)	$ 35.88	
Outstanding at December 31, 2008	14,690	$ 33.52	
Granted	52,450	$ 10.05	
Outstanding at December 31, 2009	67,140	$ 15.18	$ 29.57
Expected to vest	49,785	$ 16.30	$ 29.57

The estimate of RPUs that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate, which was estimated at 30% for units granted in 2009 and 23% for units granted in 2008. 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 certain awards issued under the LTIP in cash upon vesting. Compensation expense on these awards is recognized ratably over each vesting period, and will be re-measured each reporting period 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.

15. Income Taxes

We are structured as a master limited partnership, which is a pass-through entity for federal income tax purposes. Accordingly, we had no federal deferred tax balances as of December 31, 2009, 2008 and 2007, and no federal income tax expense for the years ended December 31, 2009, 2008 and 2007.

The State of Texas imposes a margin tax that is assessed at 1% of taxable margin apportioned to Texas. Accordingly, we have recorded current tax expense for the Texas margin tax beginning in 2007. As a result of our acquisition of an additional 25.1% limited liability company interest in East Texas in April 2009, in a transaction among entities under common control, and our subsequent consolidation of East Texas as a subsidiary, we recorded a non-current deferred tax liability of $1.8 million at December 31, 2006. During 2008 we acquired properties in Michigan. Michigan imposes a business tax of 0.8% on gross receipts, and 4.95% of Michigan taxable income. The sum of the gross receipts and income tax is subject to a tax surcharge of 21.99%. Michigan provides tax credits that may reduce our final tax liability.

Income tax expense for the years ended December 31, 2009, 2008 and 2007, consisted of current tax expense of $0.5 million, $0.7 million and $0.9 million, respectively and deferred tax expense of $0.1 million for 2009 and deferred tax benefit of $0.1 million for 2008 and 2007. Our effective tax rate differs from statutory rates, primarily due to being structured as a limited partnership, which is a pass-through entity for United States income tax purposes, while being treated as a taxable entity in certain states.

16. Net Income or Loss per Limited Partner Unit

Our net income or loss is allocated to the general partner and the limited partners, including the holders of the subordinated units, through the date of subordinated conversion, in accordance with their respective ownership percentages, after allocating Available Cash generated during the period in accordance with our partnership agreement.

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 loss or other financial results; however, in periods in which aggregate net income exceeds our Available Cash it will have the impact of reducing net income per LPU.

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

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 results of operations, financial position or cash flows.

El Paso — On February 27, 2009, a jury in the District Court, Harris County, Texas rendered a verdict in favor of El Paso E&P Company, L.P., or El Paso, and against one of our subsidiaries and DCP Midstream, LLC. As previously disclosed, the lawsuit, filed in December 2006, stems from an ongoing commercial dispute involving our Minden processing plant that dates back to August 2000. During the second quarter of 2009 we filed an appeal in the 14th Court of Appeals, Texas. El Paso filed an additional lawsuit in the District Court of Webster Parish, Louisiana, claiming damages for the same claims as the Texas matter, but for periods prior to our ownership of the Minden processing plant. The Louisiana court determined in August 2009 that El Paso's Louisiana claims were barred by the doctrine of res judicata and dismissed the case with prejudice in Louisiana. In January 2010, we and DCP Midstream, LLC entered into a settlement agreement with El Paso to resolve all claims brought by El Paso regarding this matter in Texas and Louisiana. Under the terms of the settlement agreement, we paid El Paso approximately $2.2 million for our portion of the settlement, which is within the amount of our previously disclosed contingent liability. This amount was included in the consolidated balance sheets within other current liabilities as of December 31, 2009. The cases have been dismissed in both Texas and Louisiana.

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

Insurance — We renewed our insurance policies in May, June and July 2009 for the 2009-2010 insurance year. Previously, we carried insurance jointly with DCP Midstream, LLC. Following our 2009 renewals, we now contract with a third party insurer separately from DCP Midstream, LLC for: (1) automobile liability insurance for all owned, non-owned and hired vehicles; (2) excess liability insurance above the established primary limits for general liability and automobile liability insurance; and (3) property insurance, which covers replacement value of all real and personal property and includes business interruption/extra expense. However, we are still jointly insured with DCP Midstream, LLC for directors and officers insurance covering our directors and officers for acts related to our business activities. As a result of separating the excess liability insurance, we have reduced the limits of insurance to match the type and size of exposure covered by this insurance. These changes have not resulted in any material change to the premiums we contracted to pay in the 2009-2010 insurance year. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies that are of similar size to us and with similar types of operations.

Discovery's previous property insurance policy expired in June 2009. Our insurance on Discovery for the 2009-2010 insurance year covers onshore and offshore property, onshore named windstorm and onshore business interruption insurance. The availability of named windstorm insurance has been significantly reduced as a result of higher industry-wide damage claims in past years. Additionally, the named windstorm insurance that is available comes at significantly higher premium amounts, higher deductibles and lower coverage limits. Consequently, Discovery elected to not purchase offshore named windstorm insurance coverage for the 2009-2010 insurance year.

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 certain potential environmental claims, losses and expenses associated with the operation of the assets of certain of our predecessors. 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, totaled $12.1 million, $12.9 million and $11.4 million for the years ended December 31, 2009, 2008 and 2007, 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 December 31, 2009:

	(Millions)
2010	$ 14.0
2011	13.3
2012	10.2
2013	7.8
2014	4.0
Thereafter	1.7
Total minimum rental payments	$ 51.0

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 (1) our Northern Louisiana system; (2) our Southern Oklahoma system, acquired in May 2007; (3) our 40% limited liability company interest in Discovery, and the Swap, acquired in July 2007; (4) our Colorado and Wyoming systems, acquired in August 2007; (5) our East Texas system; and (6) our Michigan systems, acquired in October 2008 and November 2009.

Wholesale Propane Logistics — The Wholesale Propane Logistics segment consists of five owned and operated rail terminals, one leased marine terminal, one pipeline terminal and access to several open-access pipeline terminals.

NGL Logistics — The NGL Logistics segment consists of the Seabreeze and Wilbreeze NGL transportation pipelines, and a non-operated 45% equity interest in the Black Lake interstate NGL pipeline. 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:

Year Ended December 31, 2009:

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other	Total
			(Millions)		
Total operating revenue	$ 583.7	$ 348.2	$ 10.5	$ —	$ 942.4
Gross margin (a)	$ 109.7	$ 48.9	$ 7.6	$ —	$ 166.2
Operating and maintenance expense	(58.2)	(10.3)	(1.2)	—	(69.7)
Depreciation and amortization expense	(61.9)	(1.4)	(1.4)	(0.2)	(64.9)
General and administrative expense	—	—	—	(32.3)	(32.3)
Earnings from unconsolidated affiliates	16.6	—	1.9	—	18.5
Interest income	—	—	—	0.3	0.3
Interest expense	—	—	—	(28.3)	(28.3)
Income tax expense (b)	—	—	—	(0.6)	(0.6)
Net income (loss)	6.2	37.2	6.9	(61.1)	(10.8)
Net income attributable to noncontrolling interests	(8.3)	—	—	—	(8.3)
Net (loss) income attributable to partners	$ (2.1)	$ 37.2	$ 6.9	$(61.1)	$ (19.1)
Non-cash derivative mark-to-market (c)	$ (84.2)	$ 0.8	$ —	$ (0.4)	$ (83.8)
Capital expenditures	$ 164.3	$ 0.5	$ —	$ —	$ 164.8

Year Ended December 31, 2008:

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other	Total
			(Millions)		
Total operating revenue	$1,336.2	$ 483.0	$ 11.3	$ —	$1,830.5
Gross margin (a)	$ 331.4	$ 11.0	$ 7.1	$ —	$ 349.5
Operating and maintenance expense	(66.5)	(9.9)	(1.0)	—	(77.4)
Depreciation and amortization expense	(50.5)	(1.3)	(1.4)	—	(53.2)
General and administrative expense	—	—	—	(33.3)	(33.3)
Other	—	1.5	—	—	1.5
Earnings from unconsolidated affiliates	17.4	—	0.8	—	18.2
Interest income	—	—	—	6.1	6.1
Interest expense	—	—	—	(32.8)	(32.8)
Income tax expense (b)	—	—	—	(0.6)	(0.6)
Net income (loss)	231.8	1.3	5.5	(60.6)	178.0
Net income attributable to noncontrolling interests	(36.1)	—	—	—	(36.1)
Net income (loss) attributable to partners	$ 195.7	$ 1.3	$ 5.5	$(60.6)	$ 141.9
Non-cash derivative mark-to-market (c)	$ 99.2	$ 2.4	$ —	$ (0.6)	$ 101.0
Capital expenditures	$ 68.3	$ 3.3	$ 0.4	$ 0.7	$ 72.7

Year Ended December 31, 2007:

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other	Total
			(Millions)		
Total operating revenue	$877.0	$ 459.6	$ 9.6	$ —	$1,346.2
Gross margin (a)	$130.2	$ 25.5	$ 4.9	$ —	$ 160.6
Operating and maintenance expense	(48.1)	(10.4)	(0.8)	—	(59.3)
Depreciation and amortization expense	(37.7)	(1.1)	(1.4)	—	(40.2)
General and administrative expense	—	—	—	(36.2)	(36.2)
Earnings from unconsolidated affiliates	24.1	—	0.6	—	24.7
Interest income	—	—	—	5.6	5.6
Interest expense	—	—	—	(25.7)	(25.7)
Income tax expense (b)	—	—	—	(0.8)	(0.8)
Net income (loss)	68.5	14.0	3.3	(57.1)	28.7
Net income attributable to noncontrolling interests	(29.8)	—	—	—	(29.8)
Net income (loss) attributable to partners	$ 38.7	$ 14.0	$ 3.3	$(57.1)	$ (1.1)
Non-cash derivative mark-to-market (c)	$ (78.3)	$ (2.8)	$ —	$ —	$ (81.1)
Capital expenditures	$ 40.5	$ 3.9	$ 1.2	$ —	$ 45.6

	December 31, 2009	2008	2007
		(Millions)	
Segment long-term assets:			
Natural Gas Services (d)	$1,185.2	$1,045.9	$ 884.4
Wholesale Propane Logistics	53.2	54.3	52.6
NGL Logistics	32.3	33.8	34.8
Other (e)	13.1	70.3	104.1
Total long-term assets	1,283.8	1,204.3	1,075.9
Current assets	197.7	215.4	304.9
Total assets	$1,481.5	$1,419.7	$1,380.8

(a) Gross margin consists of total operating revenues, including commodity derivative activity, 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 in 2009 relates primarily to the Texas margin tax and the Michigan business tax. Income tax expense in 2008 and 2007 relates primarily to the Texas margin tax.

(c) Non-cash derivative mark-to-market is included in segment gross margin, along with cash settlements for our derivative contracts.

(d) Long-term assets for our Natural Gas Services segment increased in 2009 as a result of; (1) Our expansion projects in East Texas and the Piceance basin; and (2) the acquisition of certain companies that held natural gas gathering and treating assets for $45.1 million from MichCon Pipeline Company.

(e) Other long-term assets not allocable to segments consist of restricted investments, unrealized gains on derivative instruments, corporate leasehold improvements and other long-term assets.

19. Supplemental Cash Flow Information

	Year Ended December 31,		
	2009	2008	2007
		(Millions)	
Cash paid for interest:			
Cash paid for interest, net of amounts capitalized	$ 9.0	$ 26.3	$ 26.5
Cash paid for income taxes, net of income tax refunds	$ 1.5	$ —	$ —
Non-cash investing and financing activities:			
Property, plant and equipment acquired with accounts payable	$ 4.1	$ 17.4	$ 11.1
Other non-cash additions of property, plant and equipment	$ 1.3	$ 5.5	$ 0.7
Accounts payable related to acquisitions	$ —	$ —	$ 9.0
Accrued distributions to DCP Midstream, LLC related to reimbursements	$ —	$ —	$ 0.5
Accrued contributions from DCP Midstream, LLC related to reimbursements	$ —	$ —	$ 0.5
Accrued equity-based compensation	$ —	$ 0.2	$ 0.2

20. Quarterly Financial Data (Unaudited)

In April 2009, we acquired an additional 25.1% limited liability company interest in East Texas, in a transaction among entities under common control. Prior to this transaction we owned a 25% limited liability company interest in East Texas, which we accounted for under the equity method of accounting. Subsequent to this transaction we own a 50.1% limited liability company interest in East Texas, and account for East Texas as a consolidated subsidiary. Accordingly, the results of operations by quarter have been retroactively adjusted to include the results of East Texas on a consolidated basis, for all periods presented.

Our consolidated results of operations by quarter for the years ended December 31, 2009, 2008 and 2007 were as follows (millions, except per unit amounts):

2009	First	Second	Third	Fourth	Year Ended December 31, 2009
Total operating revenues	$284.4	$ 152.0	$205.7	$300.3	$ 942.4
Operating income (loss)	$ 28.1	$ (36.8)	$ 11.1	$ (3.1)	$ (0.7)
Net income (loss)	$ 19.8	$ (40.0)	$ 12.4	$ (3.0)	$ (10.8)
Net loss (income) attributable to noncontrolling interests	$ 1.3	$ (2.1)	$ (2.5)	$ (5.0)	$ (8.3)
Net income (loss) attributable to partners	$ 21.1	$ (42.1)	$ 9.9	$ (8.0)	$ (19.1)
Limited partners' interest in net income (loss) (a)	$ 18.9	$ (44.8)	$ 6.5	$ (11.4)	$ (30.8)
Basic net income (loss) per limited partner unit (a)	$ 0.67	$ (1.41)	$ 0.21	$ (0.35)	$ (0.99)

2008	First	Second	Third	Fourth	Year Ended December 31, 2008
Total operating revenues	$479.3	$ 344.3	$552.1	$454.8	$ 1,830.5
Operating income (loss)	$ 9.8	$(140.7)	$160.0	$158.0	$ 187.1
Net income (loss)	$ 13.8	$(139.8)	$159.8	$144.2	$ 178.0
Net income attributable to noncontrolling interests	$ (13.7)	$ (13.3)	$ (5.0)	$ (4.1)	$ (36.1)
Net income (loss) attributable to partners	$ 0.1	$(153.1)	$154.8	$140.1	$ 141.9
Limited partners' interest in net (loss) income (a)	$ (9.2)	$(160.0)	$147.8	$134.1	$ 112.7
Basic net (loss) income per limited partner unit (a)	$ (0.37)	$ (5.67)	$ 5.24	$ 4.75	$ 4.11

2007	First	Second	Third	Fourth	Year Ended December 31, 2007
Total operating revenues	$331.5	$ 291.3	$307.1	$416.3	$ 1,346.2
Operating income (loss)	$ 21.0	$ 7.6	$ 19.3	$ (23.0)	$ 24.9
Net income (loss)	$ 23.0	$ 8.0	$ 19.2	$ (21.5)	$ 28.7
Net income attributable to noncontrolling interests	$ (4.8)	$ (4.8)	$ (7.9)	$ (12.3)	$ (29.8)
Net income (loss) attributable to partners	$ 18.2	$ 3.2	$ 11.3	$ (33.8)	$ (1.1)
Limited partners' interest in net income (loss) (a)(b)	$ 12.0	$ (0.2)	$ 6.0	$ (41.1)	$ (23.3)
Basic net income (loss) per limited partner unit (a)(b)	$ 0.68	$ (0.01)	$ 0.27	$ (1.71)	$ (1.14)

Our consolidated results of operations by quarter, as previously reported, were as follows (millions, except per unit amounts):

2009	Three Months Ended March 31, 2009
Total operating revenues	$ 240.6
Operating income	$ 32.4
Net income	$ 23.0
Net income attributable to noncontrolling interests	$ (0.9)
Net income attributable to partners	$ 22.1
Limited partners' interest in net income (a)	$ 18.9
Basic net income per limited partner unit (a)	$ 0.67

2008	First	Second	Third	Fourth	Year Ended December 31, 2008
Total operating revenues	$337.7	$ 145.9	$426.8	$375.4	$ 1,285.8
Operating (loss) income	$ (16.6)	$(165.7)	$152.4	$152.5	$ 122.6
Net (loss) income	$ (5.9)	$(158.4)	$153.9	$140.0	$ 129.6
Net income attributable to noncontrolling interests	$ (0.6)	$ (0.9)	$ (1.2)	$ (1.2)	$ (3.9)
Net (loss) income attributable to partners	$ (6.5)	$(159.3)	$152.7	$138.8	$ 125.7
Limited partners' interest in net (loss) income (a)	$ (9.2)	$(160.0)	$147.8	$134.1	$ 112.7
Basic net (loss) income per limited partner unit (a)	$ (0.37)	$ (5.67)	$ 5.24	$ 4.75	$ 4.11

2007	First	Second	Third	Fourth	Year Ended December 31, 2007
Total operating revenues	$237.2	$ 181.1	$188.6	$266.4	$ 873.3
Operating income (loss)	$ 11.5	$ (1.8)	$ 3.9	$ (47.6)	$ (34.0)
Net income (loss)	$ 15.8	$ 0.8	$ 7.8	$ (39.7)	$ (15.3)
Net income attributable to noncontrolling interests	$ —	$ —	$ (0.3)	$ (0.2)	$ (0.5)
Net income (loss) attributable to partners	$ 15.8	$ 0.8	$ 7.5	$ (39.9)	$ (15.8)
Limited partners' interest in net income (loss) (a)(b)	$ 12.0	$ (0.2)	$ 6.0	$ (41.1)	$ (23.3)
Basic net income (loss) per limited partner unit (a)(b)	$ 0.68	$ (0.01)	$ 0.27	$ (1.71)	$ (1.14)

Our results of operations by quarter for our additional 25.1% interest in East Texas for the three months ended March 31, 2009 and the years ended December 31, 2008 and 2007, are as follows (millions):

2009	Three Months Ended March 31, 2009
Total operating revenues	$ 43.8
Operating loss	$ (4.3)
Net loss	$ (3.2)
Net loss attributable to noncontrolling interests	$ 2.2
Net income attributable to partners	$ (1.0)
Limited partners' interest in net income (a)	$ N/A
Basic net income per limited partner unit (a)	$ N/A

2008	First	Second	Third	Fourth	Year Ended December 31, 2008
Total operating revenues	$141.6	$198.4	$125.3	$ 79.4	$ 544.7
Operating income	$ 26.4	$ 25.0	$ 7.6	$ 5.5	$ 64.5
Net income	$ 19.7	$ 18.6	$ 5.9	$ 4.2	$ 48.4
Net income attributable to noncontrolling interests	$ (13.1)	$ (12.4)	$ (3.8)	$ (2.9)	$ (32.2)
Net income attributable to partners	$ 6.6	$ 6.2	$ 2.1	$ 1.3	$ 16.2
Limited partners' interest in net income (a)	$ N/A	$ N/A	$ N/A	$ N/A	$ N/A
Basic net income per limited partner unit (a)	$ N/A	$ N/A	$ N/A	$ N/A	$ N/A

2007	First	Second	Third	Fourth	Year Ended December 31, 2007
Total operating revenues	$ 94.3	$110.2	$118.5	$149.9	$ 472.9
Operating income	$ 9.5	$ 9.4	$ 15.4	$ 24.6	$ 58.9
Net income	$ 7.2	$ 7.2	$ 11.4	$ 18.2	$ 44.0
Net income attributable to noncontrolling interests	$ (4.8)	$ (4.8)	$ (7.6)	$ (12.1)	$ (29.3)
Net income attributable to partners	$ 2.4	$ 2.4	$ 3.8	$ 6.1	$ 14.7
Limited partners' interest in net income (a)(b)	$ N/A	$ N/A	$ N/A	$ N/A	$ N/A
Basic net income per limited partner unit (a)(b)	$ N/A	$ N/A	$ N/A	$ N/A	$ N/A

(a) Total limited partners' interest in net income and basic income per limited partner unit excludes the results from our additional 25.1% interest in East Texas for the period January 1, 2007 through March 31, 2009.

(b) Total limited partners' interest in net income and basic income per limited partner unit excludes the results from our initial 25% interest in East Texas, our 40% interest in Discovery and the Swap for the period January 1, 2007 through June 30, 2007.

21. Supplementary Information — Condensed Consolidating Financial Information

The following condensed consolidating financial information presents the results of operations, financial position and cash flows of DCP Midstream Partners, LP, or parent guarantor, DCP Midstream Operating LP, or subsidiary issuer, which is a wholly owned subsidiary, and non-guarantor subsidiaries, as well as the consolidating adjustments necessary to present DCP Midstream Partners, LP's results on a consolidated basis. The parent guarantor has agreed to fully and unconditionally guarantee securities of the subsidiary issuer that may be issued in future periods. For the purpose of the following financial information, investments in subsidiaries are reflected in accordance with the equity method of accounting. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had the subsidiaries operated as independent entities.

	December 31, 2009				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ 1.6	$ 1.3	$ (0.8)	$ 2.1
Accounts receivable	—	—	152.5	—	152.5
Inventories	—	—	34.2	—	34.2
Other	—	0.1	8.8	—	8.9
Total current assets	—	1.7	196.8	(0.8)	197.7
Restricted investments	—	10.0	—	—	10.0
Property, plant and equipment, net	—	—	1,000.1	—	1,000.1
Goodwill and intangible assets, net	—	—	152.6	—	152.6
Advances receivable — consolidated subsidiaries	245.8	520.0	—	(765.8)	—
Investments in consolidated subsidiaries	131.9	245.3	—	(377.2)	—
Investments in unconsolidated affiliates	—	—	114.6	—	114.6
Other long-term assets	—	0.6	5.9	—	6.5
Total assets	$ 377.7	$ 777.6	$ 1,470.0	$ (1,143.8)	$ 1,481.5
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$ —	$ 21.1	$ 170.8	$ (0.8)	$ 191.1
Advances payable — consolidated subsidiaries	—	—	765.8	(765.8)	—
Long-term debt	—	613.0	—	—	613.0
Other long-term liabilities	—	11.6	60.4	—	72.0
Total liabilities	—	645.7	997.0	(766.6)	876.1
Commitments and contingent liabilities					
Equity:					
Partners' equity:					
Net equity	377.7	163.0	246.1	(377.2)	409.6
Accumulated other comprehensive loss	—	(31.1)	(0.8)	—	(31.9)
Total partners' equity	377.7	131.9	245.3	(377.2)	377.7
Noncontrolling interests	—	—	227.7	—	227.7
Total equity	377.7	131.9	473.0	(377.2)	605.4
Total liabilities and equity	$ 377.7	$ 777.6	$ 1,470.0	$ (1,143.8)	$ 1,481.5

	December 31, 2008				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ 26.6	$ 35.6	$ (0.3)	$ 61.9
Accounts receivable	—	—	116.3	—	116.3
Inventories	—	—	20.9	—	20.9
Other	—	—	16.3	—	16.3
Total current assets	—	26.6	189.1	(0.3)	215.4
Restricted investments	—	60.2	—	—	60.2
Property, plant and equipment, net	—	—	882.7	—	882.7
Goodwill and intangible assets, net	—	—	136.5	—	136.5
Advances receivable — consolidated subsidiaries	211.9	516.3	—	(728.2)	—
Investments in consolidated subsidiaries	183.2	276.3	—	(459.5)	—
Investments in unconsolidated affiliates	—	—	111.5	—	111.5
Other long-term assets	—	0.8	12.6	—	13.4
Total assets	$ 395.1	$ 880.2	$ 1,332.4	$ (1,188.0)	$ 1,419.7
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$ —	$ 17.7	$ 145.8	$ (0.3)	$ 163.2
Advances payable — consolidated subsidiaries	—	—	728.2	(728.2)	—
Long-term debt	—	656.5	—	—	656.5
Other long-term liabilities	—	22.8	14.4	—	37.2
Total liabilities	—	697.0	888.4	(728.5)	856.9
Commitments and contingent liabilities					
Equity:					
Partners' equity:					
Net equity	395.1	221.9	278.1	(459.5)	435.6
Accumulated other comprehensive loss	—	(38.7)	(1.8)	—	(40.5)
Total partners' equity	395.1	183.2	276.3	(459.5)	395.1
Noncontrolling interests	—	—	167.7	—	167.7
Total equity	395.1	183.2	444.0	(459.5)	562.8
Total liabilities and equity	$ 395.1	$ 880.2	$ 1,332.4	$ (1,188.0)	$ 1,419.7

	Year Ended December 31, 2009				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 913.0	$ —	$ 913.0
Transportation, processing and other	—	—	95.2	—	95.2
Losses from commodity derivative activity, net	—	—	(65.8)	—	(65.8)
Total operating revenues	—	—	942.4	—	942.4
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	(776.2)	—	(776.2)
Operating and maintenance expense	—	—	(69.7)	—	(69.7)
Depreciation and amortization expense	—	—	(64.9)	—	(64.9)
General and administrative expense	—	(0.1)	(32.2)	—	(32.3)
Total operating costs and expenses	—	(0.1)	(943.0)	—	(943.1)
Operating loss	—	(0.1)	(0.6)	—	(0.7)
Interest expense, net	—	(27.8)	(0.2)	—	(28.0)
Earnings from unconsolidated affiliates	—	—	18.5	—	18.5
(Losses) Earnings from consolidated subsidiaries	(19.1)	8.8	—	10.3	—
(Loss) income before income taxes	(19.1)	(19.1)	17.7	10.3	(10.2)
Income tax expense	—	—	(0.6)	—	(0.6)
Net (loss) income	(19.1)	(19.1)	17.1	10.3	(10.8)
Net income attributable to noncontrolling interests	—	—	(8.3)	—	(8.3)
Net (loss) income attributable to partners	$ (19.1)	$ (19.1)	$ 8.8	$ 10.3	$ (19.1)

	Year Ended December 31, 2008				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 1,672.7	$ —	$ 1,672.7
Transportation, processing and other	—	—	86.1	—	86.1
Gains from commodity derivative activity, net	—	—	71.7	—	71.7
Total operating revenues	—	—	1,830.5	—	1,830.5
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	(1,481.0)	—	(1,481.0)
Operating and maintenance expense	—	—	(77.4)	—	(77.4)
Depreciation and amortization expense	—	—	(53.2)	—	(53.2)
General and administrative expense	—	(0.1)	(33.2)	—	(33.3)
Other, net	—	—	1.5	—	1.5
Total operating costs and expenses	—	(0.1)	(1,643.3)	—	(1,643.4)
Operating (loss) income	—	(0.1)	187.2	—	187.1
Interest (expense) income, net	—	(27.1)	0.4	—	(26.7)
Earnings from unconsolidated affiliates	—	—	18.2	—	18.2
Earnings from consolidated subsidiaries	141.9	169.1	—	(311.0)	—
Income before income taxes	141.9	141.9	205.8	(311.0)	178.6
Income tax expense	—	—	(0.6)	—	(0.6)
Net income	141.9	141.9	205.2	(311.0)	178.0
Net income attributable to noncontrolling interests	—	—	(36.1)	—	(36.1)
Net income attributable to partners	$ 141.9	$ 141.9	$ 169.1	$ (311.0)	$ 141.9

	Year Ended December 31, 2007				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 1,376.5	$ —	$ 1,376.5
Transportation, processing and other	—	—	57.4	—	57.4
Losses from commodity derivative activity, net	—	—	(87.7)	—	(87.7)
Total operating revenues	—	—	1,346.2	—	1,346.2
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	(1,185.6)	—	(1,185.6)
Operating and maintenance expense	—	—	(59.3)	—	(59.3)
Depreciation and amortization expense	—	—	(40.2)	—	(40.2)
General and administrative expense	—	(0.3)	(35.9)	—	(36.2)
Total operating costs and expenses	—	(0.3)	(1,321.0)	—	(1,321.3)
Operating (loss) income	—	(0.3)	25.2	—	24.9
Interest (expense) income, net	—	(20.5)	0.4	—	(20.1)
Earnings from unconsolidated affiliates	—	—	24.7	—	24.7
(Losses) earnings from consolidated subsidiaries	(1.1)	19.7	—	(18.6)	—
(Loss) income before income taxes	(1.1)	(1.1)	50.3	(18.6)	29.5
Income tax expense	—	—	(0.8)	—	(0.8)
Net (loss) income	(1.1)	(1.1)	49.5	(18.6)	28.7
Net income attributable to noncontrolling interests	—	—	(29.8)	—	(29.8)
Net (loss) income attributable to partners	$ (1.1)	$ (1.1)	$ 19.7	$ (18.6)	$ (1.1)

	Year Ended December 31, 2009				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ 15.8	$ (31.5)	$ 124.1	$ (0.5)	$ 107.9
INVESTING ACTIVITIES:					
Capital expenditures	—	—	(164.8)	—	(164.8)
Acquisitions, net of cash acquired	—	—	(44.5)	—	(44.5)
Investments in unconsolidated affiliates	—	—	(7.0)	—	(7.0)
Return of investment from unconsolidated affiliate			2.2	—	2.2
Proceeds from sale of assets	—	—	0.3	—	0.3
Purchase of available-for-sale securities	—	(1.1)	—	—	(1.1)
Proceeds from sales of available-for-sale securities	—	51.1	—	—	51.1
Net cash provided by (used in) investing activities	—	50.0	(213.8)	—	(163.8)
FINANCING ACTIVITIES:					
Proceeds from debt	—	237.0	—	—	237.0
Payments of debt	—	(280.5)	—	—	(280.5)
Proceeds from issuance of common units, net of offering costs	69.5	—	—	—	69.5
Net change in advances to predecessor from DCP Midstream, LLC	—	—	3.0	—	3.0
Distributions to unitholders and general partner	(85.3)	—	—	—	(85.3)
Distributions to noncontrolling interests	—	—	(27.0)	—	(27.0)
Contributions from noncontrolling interests	—	—	78.7	—	78.7
Contributions from DCP Midstream, LLC	—	—	0.7	—	0.7
Net cash provided by (used in) financing activities	(15.8)	(43.5)	55.4	—	(3.9)
Net change in cash and cash equivalents	—	(25.0)	(34.3)	(0.5)	(59.8)
Cash and cash equivalents, beginning of period	—	26.6	35.6	(0.3)	61.9
Cash and cash equivalents, end of period	$ —	$ 1.6	$ 1.3	$ (0.8)	$ 2.1

	Year Ended December 31, 2008				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ (56.4)	$ (52.8)	$ 285.5	$ 1.3	$ 177.6
INVESTING ACTIVITIES:					
Capital expenditures	—	—	(72.7)	—	(72.7)
Acquisitions, net of cash acquired	—	—	(157.3)	—	(157.3)
Investments in unconsolidated affiliates	—	—	(7.4)	—	(7.4)
Proceeds from sale of assets	—	—	2.9	—	2.9
Purchase of available-for-sale securities	—	(608.2)	—	—	(608.2)
Proceeds from sales of available-for-sale securities	—	650.5	—	—	650.5
Net cash provided by (used in) investing activities	—	42.3	(234.5)	—	(192.2)
FINANCING ACTIVITIES:					
Proceeds from debt	—	660.4	—	—	660.4
Payments of debt	—	(633.9)	—	—	(633.9)
Proceeds from issuance of common units, net of offering costs	132.1	—	—	—	132.1
Net change in advances to predecessor from DCP Midstream, LLC	—	—	(14.2)	—	(14.2)
Distributions to unitholders and general partner	(75.7)	—	(0.5)	—	(76.2)
Distributions to noncontrolling interests	—	—	(46.4)	—	(46.4)
Contributions from noncontrolling interests	—	—	21.3	—	21.3
Contributions from DCP Midstream, LLC	—	—	4.1	—	4.1
Net cash provided by (used in) financing activities	56.4	26.5	(35.7)	—	47.2
Net change in cash and cash equivalents	—	16.0	15.3	1.3	32.6
Cash and cash equivalents, beginning of period	—	10.6	20.3	(1.6)	29.3
Cash and cash equivalents, end of period	$ —	$ 26.6	$ 35.6	$ (0.3)	$ 61.9

	Year Ended December 31, 2007				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ (184.7)	$ (400.5)	$ 672.1	$ (0.4)	$ 86.5
INVESTING ACTIVITIES:					
Capital expenditures	—	—	(45.6)	—	(45.6)
Acquisitions, net of cash acquired	—	—	(333.3)	—	(333.3)
Acquisition of unconsolidated affiliates	—	—	(153.3)	—	(153.3)
Investments in unconsolidated affiliates	—	—	(3.9)	—	(3.9)
Payment of earnest deposit	—	—	(9.0)	—	(9.0)
Refund of earnest deposit	—	—	9.0	—	9.0
Proceeds from sale of assets	—	—	0.1	—	0.1
Purchase of available-for-sale securities	—	(6,921.6)	—	—	(6,921.6)
Proceeds from sales of available-for-sale securities	—	6,924.0	—	—	6,924.0
Net cash provided by (used in) investing activities	—	2.4	(536.0)	—	(533.6)
FINANCING ACTIVITIES:					
Proceeds from debt	—	579.0	—	—	579.0
Payments of debt	—	(217.0)	—	—	(217.0)
Payment of deferred financing costs	—	(0.6)	—	—	(0.6)
Purchase of units	(0.3)	—	—	—	(0.3)
Proceeds from issuance of common units, net of offering costs	228.5	—	—	—	228.5
Excess purchase price over acquired assets	—	—	(100.3)	—	(100.3)
Net change in advances to predecessor from DCP Midstream, LLC	—	—	(16.4)	—	(16.4)
Distributions to unitholders and general partner	(43.5)	—	(0.5)	—	(44.0)
Distributions to noncontrolling interests	—	—	(30.8)	—	(30.8)
Contributions from noncontrolling interests	—	—	31.6	—	31.6
Contributions from DCP Midstream, LLC	—	—	0.5	—	0.5
Net cash provided by (used in) financing activities	184.7	361.4	(115.9)	—	430.2
Net change in cash and cash equivalents	—	(36.7)	20.2	(0.4)	(16.9)
Cash and cash equivalents, beginning of period	—	47.3	0.1	(1.2)	46.2
Cash and cash equivalents, end of period	$ —	$ 10.6	$ 20.3	$ (1.6)	$ 29.3

22. Subsequent Events

On January 26, 2010, the board of directors of the general partner declared a quarterly distribution of $0.60 per unit, payable on February 12, 2010 to unitholders of record on February 5, 2010.

On January 28, 2010, we announced that we acquired an interstate natural gas liquids pipeline from Buckeye Partners, L.P., for $22.0 million in cash, funded with borrowings under our revolving credit facility. The 350-mile pipeline originates in the Denver-Julesburg, or DJ, Basin in Colorado and terminates near the Conway hub in Bushton, Kansas. The pipeline is currently utilized by DCP Midstream, LLC as a market outlet for NGL production from certain of their plants in the DJ Basin. In conjunction with the acquisition we have agreed to a 10 year transportation agreement with DCP Midstream, LLC. The acquired pipeline will generate 100 percent fee-based revenues, with the results of the assets being included in our NGL logistics segment prospectively, from the date of acquisition. The accounting for our acquisition of the pipeline was incomplete at the time we issued our consolidated financial statements. Accordingly, it is impracticable for us to make certain business combination disclosures including the allocation of purchase price among the fair value of assets acquired and liabilities assumed, or assets and liabilities arising from contingencies. Additionally, in the absence of such information we were unable to calculate the amount of goodwill and intangibles acquired or supplemental pro-forma combined information for the most recent period presented. The disclosure required for business combinations will be made in a subsequent filing.

DCP MIDSTREAM PARTNERS, LP

SCHEDULE II — CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

	Balance at Beginning of Period	Charged to Consolidated Statements of Operations	Charged to Other Accounts (a) (Millions)	Deductions/ Other	Balance at End of Period
December 31, 2009					
Allowance for doubtful accounts	$ 1.0	$ —	$ —	$ (0.5)	$ 0.5
Environmental	1.9	—	—	(0.8)	1.1
Litigation	2.5	—	—	(0.1)	2.4
Other (b)	0.1	—	—	—	0.1
	$ 5.5	$ —	$ —	$ (1.4)	$ 4.1
December 31, 2008					
Allowance for doubtful accounts	$ 1.7	$ —	$ —	$ (0.7)	$ 1.0
Environmental	1.8	0.5	—	(0.4)	1.9
Litigation	—	2.5	—	—	2.5
Other (b)	—	—	—	0.1	0.1
	$ 3.5	$ 3.0	$ —	$ (1.0)	$ 5.5
December 31, 2007					
Allowance for doubtful accounts	$ 0.5	$ 1.3	$ 0.2	$ (0.3)	$ 1.7
Environmental	0.4	0.2	1.6	(0.4)	1.8
Other (b)	0.3	—	—	(0.3)	—
	$ 1.2	$ 1.5	$ 1.8	$ (1.0)	$ 3.5

(a) Related to acquisition of certain subsidiaries of Momentum Energy Group, Inc.

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