ALLIANCE ONE INTERNATIONAL, INC.
Form SC 13G/A
February 10, 2014

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

SCHEDULE 13G

Under the Securities Exchange Act of 1934

(Amendment No. 2)*

ALLIANCE ONE INTERNATIONAL

(Name of Issuer)

Common Stock

(Title of Class of Securities)

018772103

(CUSIP Number)

December 31, 2013

(Date of Event Which Requires Filing of this Statement)

Check the appropriate box to designate the rule pursuant to which this Schedule is filed:

x Rule 13d-1(b)

¨ Rule 13d-1(c)

¨ Rule 13d-1(d)

* The remainder of this cover page shall be filled out for a reporting person s initial filing on this form with respect to the subject class of securities, and for any subsequent amendment containing information which would alter the disclosures provided in a prior cover page.

The information required in the remainder of this cover page shall not be deemed to be filed for the purpose of Section 18 of the Securities Exchange Act of 1934 (Act) or otherwise subject to the liabilities of that section of the Act but shall be subject to all other provisions of the Act (however, see the Notes).

CUSIP No. 018772103

1. Names of Reporting Persons.

   I.R.S. Identification Nos. of above persons (entities only).

   Dimensional Fund Advisors LP (Tax ID: 30-0447847)

2. Check the Appropriate Box if a Member of a Group (See Instructions)

   (a) ¨

   (b) x

3. SEC Use Only

4. Citizenship or Place of Organization

   Delaware Limited Partnership

Number of Shares Beneficially Owned by Each Reporting Person With	5. Sole Voting Power 5495308 **see Note 1**
	6. Shared Voting Power 0
	7. Sole Dispositive Power 5628813 **see Note 1**
	8. Shared Dispositive Power

0

9. Aggregate Amount Beneficially Owned by Each Reporting Person

5628813 **see Note 1**

10. Check if the Aggregate Amount in Row (9) Excludes Certain Shares (See Instructions)

N/A

11. Percent of Class Represented by Amount in Row (9)

6.39%

12. Type of Reporting Person (See Instructions)

IA

Item 1.

(a) Name of Issuer

ALLIANCE ONE INTERNATIONAL

(b) Address of Issuer s Principal Executive Offices

8001 Aerial Center Parkway, Morrisville,NC 27560

Item 2.

(a) Name of Person Filing

Dimensional Fund Advisors LP

(b) Address of Principal Business Office or, if none, Residence

Palisades West, Building One

6300 Bee Cave Road

Austin, Texas, 78746

(c) Citizenship

Delaware Limited Partnership

(d) Title of Class of Securities

Common Stock

(e) CUSIP Number

018772103

Item 3. If this statement is filed pursuant to §§240.13d-1(b) or 240.13d-2(b) or (c), check whether the person filing is a:

(a) ¨ Broker or dealer registered under section 15 of the Act (15 U.S.C. 78o).

(b) ¨ Bank as defined in section 3(a)(6) of the Act (15 U.S.C. 78c).

(c) ¨ Insurance company as defined in section 3(a)(19) of the Act (15 U.S.C. 78c).

(d) ¨ Investment company registered under section 8 of the Investment Company Act of 1940 (15 U.S.C 80a-8).

(e) x An investment adviser in accordance with §240.13d-1(b)(1)(ii)(E);

(f) ¨ An employee benefit plan or endowment fund in accordance with §240.13d-1(b)(1)(ii)(F);

(g) ¨ A parent holding company or control person in accordance with §240.13d-1(b)(1)(ii)(G);

(h) ¨ A savings associations as defined in Section 3(b) of the Federal Deposit Insurance Act (12 U.S.C. 1813);

(i) ¨ A church plan that is excluded from the definition of an investment company under section 3(c)(14) of the Investment Company Act of 1940 (15 U.S.C. 80a-3);

(j) ¨ A non-U.S. institution in accordance with §240.13d-1(b)(1)(ii)(J);

(k) ¨ Group, in accordance with §240.13d-1(b)(1)(ii)(J).

Item 4. Ownership.

Provide the following information regarding the aggregate number and percentage of the class of securities of the issuer identified in Item 1.

(a) Amount beneficially owned:

5628813 **see Note 1**

(b) Percent of class:

6.39%

(c) Number of shares as to which the person has:

(i) Sole power to vote or to direct the vote:

5495308 **see Note 1**

(ii) Shared power to vote or to direct the vote:

0

(iii) Sole power to dispose or to direct the disposition of:

5628813 **see Note 1**

(iv) Shared power to dispose or to direct the disposition of:

0

** Note 1 ** Dimensional Fund Advisors LP, an investment adviser registered under Section 203 of the Investment Advisors Act of 1940, furnishes investment advice to four investment companies registered under the Investment Company Act of 1940, and serves as investment manager to certain other commingled group trusts and separate accounts (such investment companies, trusts and accounts, collectively referred to as the Funds). In certain cases, subsidiaries of Dimensional Fund Advisors LP may act as an adviser or sub-adviser to certain Funds. In its role as investment advisor, sub-adviser and/or manager, Dimensional Fund Advisors LP or its subsidiaries (collectively, Dimensional) possess voting and/or investment power over the securities of the Issuer that are owned by the Funds, and may be deemed to be the beneficial owner of the shares of the Issuer held by the Funds. However, all securities reported in this schedule are owned by the Funds. Dimensional disclaims beneficial ownership of such securities. In addition, the filing of this Schedule 13G shall not be construed as an admission that the reporting person or any of its affiliates is the beneficial owner of any securities covered by this Schedule 13G for any other purposes than Section 13(d) of the Securities Exchange Act of 1934.

Item 5. Ownership of Five Percent or Less of a Class

If this statement is being filed to report the fact that as of the date hereof the reporting person has ceased to be the beneficial owner of more than five percent of the class of securities, check the following [ ].

Item 6. Ownership of More than Five Percent on Behalf of Another Person.

The Funds described in Note 1 above have the right to receive or the power to direct the receipt of dividends from, or the proceeds from the sale of the securities held in their respective accounts. To the knowledge of Dimensional, the interest of any one such Fund does not exceed 5% of the class of securities. Dimensional Fund Advisors LP disclaims beneficial ownership of all such securities.

Item 7. Identification and Classification of the Subsidiary Which Acquired the Security Being Reported on By the Parent Holding Company or Control Person.

N/A

Item 8. Identification and Classification of Members of the Group

N/A

Item 9. Notice of Dissolution of Group

N/A

Item 10. Certification

By signing below I certify that, to the best of my knowledge and belief, the securities referred to above were acquired and are held in the ordinary course of business and were not acquired and are not held for the purpose of or with the effect of changing or influencing the control of the issuer of the securities and were not acquired and are not held in connection with or as a participant in any transaction having that purpose or effect, other than activities solely in connection with a nomination under §240.14a-11.

SIGNATURE

After reasonable inquiry and to the best of my knowledge and belief, I certify that the information set forth in this statement is true, complete and correct.

DIMENSIONAL FUND ADVISORS LP

February 10, 2014

Date

By: Dimensional Holdings Inc., General Partner

/s/ Christopher Crossan

Signature

Global Chief Compliance Officer

Title

D VALIGN="bottom"> **2009 2008 2009 2008 (Millions)**

Reconciliation of Non-GAAP Measures

Reconciliation of net loss attributable to partners to gross margin:

Net loss attributable to partners

$(42.1) $(153.1) $(21.0) $(153.0)

Interest expense

7.0 7.9 14.3 16.0

Income tax expense

0.3 0.1 0.6

Operating and maintenance expense

17.1 19.3 33.3 37.3

Depreciation and amortization expense

16.3 13.0 30.9 25.7

General and administrative expense

7.1 7.8 15.7 15.4

Other

(1.5) (1.5)

Interest income

(0.1) (2.0) (0.3) (3.7)

Earnings from equity method investments

(3.7) (7.1) (2.6) (17.8)

Net income attributable to noncontrolling interests

2.1 13.3 0.8 27.0

Gross margin

$3.7 $(102.1) $71.2 $(54.0)

Non-cash derivative mark-to-market (a)

$(54.2) $(170.3) $(54.0) $(198.9)

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	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(Millions)			
Reconciliation of Non-GAAP Measures				
Reconciliation of segment net income (loss) attributable to partners to segment gross margin:				
Natural Gas Services segment:				
Segment net loss attributable to partners	$ (32.1)	$ (141.6)	$ (19.0)	$ (134.5)
Operating and maintenance expense	14.5	16.4	27.7	31.5
Depreciation and amortization expense	15.4	12.4	29.3	24.4
Earnings from equity method investment	(3.3)	(6.9)	(1.8)	(17.2)
Net income attributable to noncontrolling interests	2.1	13.3	0.8	27.0
Segment gross margin	$ (3.4)	$ (106.4)	$ 37.0	$ (68.8)
Non-cash derivative mark-to-market (a)	$ (54.0)	$ (170.2)	$ (53.9)	$ (201.2)
Wholesale Propane Logistics segment:				
Segment net income attributable to partners	$ 3.0	$ 0.9	$ 25.8	$ 6.5
Operating and maintenance expense	2.4	2.7	5.1	5.4
Depreciation and amortization expense	0.4	0.3	0.7	0.6
Other		(1.5)		(1.5)
Segment gross margin	$ 5.8	$ 2.4	$ 31.6	$ 11.0
Non-cash derivative mark-to-market (a)	$ (0.1)	$ (0.2)	$ 0.1	$ 2.5
NGL Logistics segment:				
Segment net income attributable to partners	$ 1.1	$ 1.6	$ 2.1	$ 3.3
Operating and maintenance expense	0.2	0.2	0.5	0.4
Depreciation and amortization expense	0.4	0.3	0.8	0.7
Earnings from equity method investment	(0.4)	(0.2)	(0.8)	(0.6)
Segment gross margin	$ 1.3	$ 1.9	$ 2.6	$ 3.8

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

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

A substantial amount of our general and administrative expense is incurred from DCP Midstream, LLC. We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for certain costs incurred and centralized corporate functions performed by DCP Midstream, LLC on our behalf. The fees under the Omnibus Agreement increased $0.4 million per year effective October 1, 2008, in connection with the Michigan acquisition. Under the Omnibus Agreement, DCP Midstream, LLC provided parental guarantees, which currently total $43.0 million, to certain counterparties to our commodity derivative instruments. We anticipate incurring a total of $9.7 million for all fees under the Omnibus Agreement in 2009. During the three months ended June 30, 2009 and 2008, we incurred $2.4 million and $2.5 million, respectively, for all fees under the Omnibus Agreement and incurred other fees to DCP Midstream, LLC of $2.7 million and $2.3 million, respectively. During the six months ended June 30, 2009 and 2008, we incurred $4.8 million and $4.9 million, respectively, for all fees under the Omnibus Agreement and incurred other fees to DCP Midstream, LLC of $5.6 million and $5.0 million, respectively.

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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 for certain obligations related to derivative financial instruments, such as commodity derivative instruments, to the extent that such credit support arrangements were in effect as of December 7, 2005 until the earlier of December 7, 2010 or when we obtain certain credit ratings from either Moody s Investor Services, Inc. or Standard & Poor s Ratings Group with respect to any of our unsecured indebtedness; and

- DCP Midstream, LLC s obligation to continue to maintain its credit support for our obligations related to commercial contracts with respect to its business or operations that were in effect at December 7, 2005 until the expiration of such contracts.

All of the fees under the Omnibus Agreement will be adjusted annually by the percentage change in the Consumer Price Index for the applicable year. In addition, our general partner will have the right to agree to further increases in connection with expansions of our operations through the acquisition or construction of new assets or businesses, with the concurrence of the special committee of DCP Midstream GP, LLC s board of directors.

The Omnibus Agreement was not amended following our acquisition of an additional 25.1% interest in East Texas on April 1, 2009. East Texas incurs general and administrative expenses directly from DCP Midstream, LLC. During the three months ended June 30, 2009 and 2008 East Texas incurred $2.2 million and $2.1 million, respectively, for general and administrative expenses from DCP Midstream, LLC. During the six months ended June 30, 2009 and 2008 East Texas incurred $4.4 million and $4.1 million, respectively, for general and administrative expenses from DCP Midstream, LLC.

We also incurred third party general and administrative expenses, which were primarily related to compensation and benefit expenses of the personnel who provide direct support to our operations. Also included are expenses associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, due diligence and acquisition costs, costs associated with the Sarbanes-Oxley Act of 2002, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs, and director compensation.

Discovery pays fees to Williams, for direct general and administrative costs incurred on their behalf. These fees reduce the amount of cash available from Discovery for distribution to us.

Adjusted EBITDA and Distributable Cash Flow We define adjusted EBITDA as net income or loss attributable to partners less interest income, noncontrolling interest in depreciation and income tax expense and non-cash commodity derivative gains, plus interest expense, income tax expense, depreciation and amortization expense and non-cash commodity derivative losses. Adjusted EBITDA is used as a supplemental liquidity and performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess:

- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness, make cash distributions to our unitholders and general partner, and finance maintenance capital expenditures;

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;

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

Our adjusted EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate these measures in the same manner.

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

We define distributable cash flow as net cash provided by or used in operating activities, less maintenance capital expenditures, net of reimbursable projects, plus or minus adjustments for non-cash mark-to-market of derivative instruments, proceeds from divestiture of assets, noncontrolling interest on depreciation, net changes in operating assets and liabilities, and

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other adjustments to reconcile net cash provided by or used in operating activities (see Liquidity and Capital Resources for further definition of maintenance capital expenditures). Maintenance capital expenditures are capital expenditures made where we add on to or improve capital assets owned, or acquire or construct new capital assets, if such expenditures are made to maintain, including over the long term, our operating capacity or revenues. Non-cash mark-to-market of derivative instruments is considered to be non-cash for the purpose of computing distributable cash flow because settlement will not occur until future periods, and will be impacted by future changes in commodity prices. Distributable cash flow is used as a supplemental liquidity measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess our ability to make cash distributions to our unitholders and our general partner. Our distributable cash flow may not be comparable to a similarly titled measure of another company because other entities may not calculate distributable cash flow in the same manner.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are described in Item 7 in our 2008 Form 10-K. The accounting policies and estimates used in preparing our interim condensed consolidated financial statements for the six months ended June 30, 2009 are the same as those described in our 2008 Form 10-K.

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Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three and six months ended June 30, 2009 and 2008. The results of operations by segment are discussed in further detail following this consolidated overview discussion:

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2009 vs. 2008		Variance Six Months 2009 vs. 2008	
	2009 (a)	2008 (b)	2009 (a)(b)	2008 (b)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Natural Gas Services (c)	$ 103.3	$ 247.3	$ 253.1	$ 522.3	$ (144.0)	(58)%	$ (269.2)	(52)%
Wholesale Propane Logistics	46.9	94.3	179.7	296.0	(47.4)	(50)%	(116.3)	(39)%
NGL Logistics	1.8	2.7	3.6	5.3	(0.9)	(33)%	(1.7)	(32)%
Total operating revenues	152.0	344.3	436.4	823.6	(192.3)	(56)%	(387.2)	(47)%
Gross margin (d):								
Natural Gas Services	(3.4)	(106.4)	37.0	(68.8)	103.0	97%	105.8	*
Wholesale Propane Logistics	5.8	2.4	31.6	11.0	3.4	142%	20.6	187%
NGL Logistics	1.3	1.9	2.6	3.8	(0.6)	(32)%	(1.2)	(32)%
Total gross margin	3.7	(102.1)	71.2	(54.0)	105.8	*	125.2	*
Operating and maintenance expense	(17.1)	(19.3)	(33.3)	(37.3)	(2.2)	(11)%	(4.0)	(11)%
Depreciation and amortization expense	(16.3)	(13.0)	(30.9)	(25.7)	3.3	25%	5.2	20%
General and administrative expense	(7.1)	(7.8)	(15.7)	(15.4)	(0.7)	(9)%	0.3	2%
Other		1.5		1.5	(1.5)	(100)%	(1.5)	(100)%
Earnings from equity method investments (d)	3.7	7.1	2.6	17.8	(3.4)	(48)%	(15.2)	(85)%
Interest income	0.1	2.0	0.3	3.7	(1.9)	(95)%	(3.4)	(92)%
Interest expense	(7.0)	(7.9)	(14.3)	(16.0)	(0.9)	(11)%	(1.7)	(11)%
Income tax expense		(0.3)	(0.1)	(0.6)	(0.3)	(100)%	(0.5)	(83)%
Net income attributable to noncontrolling interests	(2.1)	(13.3)	(0.8)	(27.0)	(11.2)	(84)%	(26.2)	(97)%
Net loss attributable to partners	$ (42.1)	$ (153.1)	$ (21.0)	$ (153.0)	$ 111.0	73%	$ 132.0	86%
Operating data:								
Natural gas throughput (MMcf/d) (e)	1,108	980	1,051	980	128	13%	71	7%
NGL gross production (Bbls/d) (e)	28,584	30,659	25,208	31,702	(2,075)	(7)%	(6,494)	(20)%
Propane sales volume (Bbls/d)	13,912	14,442	25,502	24,178	(530)	(4)%	1,324	5%
NGL pipelines throughput (Bbls/d) (e)	26,850	34,286	25,409	33,081	(7,436)	(22)%	(7,672)	(23)%

* Percentage change is not meaningful.

(a) Includes the results of MPP since October 1, 2008, the date of acquisition.

(b) In April 2009, we completed the acquisition of an additional 25.1% interest in East Texas from DCP Midstream, LLC, which results in us owning a 50.1% interest in East Texas. Prior to this transaction, we accounted for our interest in East Texas under the equity method of accounting. As a result of our owning in excess of 50%, and because the transaction was between entities under common control, we are required to present results of operations, including all historical periods, on a consolidated basis. Therefore, these results as presented are different from those originally reported in 2008, which excluded the impact of this transaction.

Additionally, note that while we utilize commodity derivative instruments to help stabilize distributable cash flows for our ownership in East Texas as well as all other natural gas services assets, the portion of East Texas owned by DCP Midstream, LLC is unhedged. As such, our consolidated results depict 75% of East Texas unhedged in all periods prior to the second quarter of 2009 and 49.9% of East Texas unhedged for all periods subsequent to the first quarter of 2009.

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Our gross margin for our Natural Gas Services segment changed from a loss of $146.2 million and $148.7 million as previously reported in 2008, to a loss of $106.4 million and $68.8 million as currently reported, for the three and six months ended June 30, 2008, respectively.

(c) Includes the effect of the acquisition of the NGL Hedge, contributed by DCP Midstream, LLC in April 2009. The NGL Hedge is a fixed price natural gas liquids derivative by NGL component for the period April 2009 to March 2010.
(d) Gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas, propane and NGLs, and segment gross margin for each segment consists of total operating revenues for that segment, less commodity purchases for that segment. Please read How We Evaluate Our Operations above.
(e) Includes our proportionate share of the throughput volumes and NGL production of Collbran, Jackson, East Texas, Black Lake and Discovery and our proportionate earnings of Black Lake and Discovery. Earnings for Discovery and Black Lake include the amortization of the net difference between the carrying amount of the investments and the underlying equity of the investments.

Three Months Ended June 30, 2009 vs. Three Months Ended June 30, 2008

Total Operating Revenues Total operating revenues decreased in 2009 compared to 2008, primarily due to the following:

- $48.5 million decrease primarily attributable to lower propane prices, for our Wholesale Propane Logistics segment;
- $288.0 million decrease primarily attributable to decreased commodity prices and a decrease in transport volumes, partially offset by a January 1, 2009 amendment to a contract with an affiliate such that our sales to the affiliate are no longer associated with our purchases from the affiliate, which resulted in a prospective change in certain Pelico revenues from a net presentation to a gross presentation, for our Natural Gas Services segment; and
- $0.7 million decrease due to decreased throughput volumes, as well as a decline in volumes from connected plants for our NGL Logistics segment; partially offset by
- $141.5 million increase related to commodity derivative activity, resulting from the following:
  - a loss of $45.9 million in 2009 and a loss of $187.3 million in 2008, resulting in a decrease in losses of $141.4 million, which is included in losses from commodity derivative activity. This decrease in losses includes a decrease in unrealized losses of $116.2 million due to forward prices of commodities generally being lower in 2009 compared to 2008 and an increase in realized cash settlement gains of $25.2 million due to average prices of commodities generally being lower in 2009 compared to 2008; and
  - a $0.1 million decrease in unrealized loss, which is included in sales of natural gas, NGLs and condensate; and
- $3.4 million increase in transportation processing and other revenue, primarily attributable to the MPP acquisition in our Natural Gas Services segment.

Gross Margin Gross margin increased in 2009 compared to 2008, primarily due to the following:

- $103.0 million increase for our Natural Gas Services segment primarily due to increases related to commodity derivative activity and the MPP acquisition, partially offset by the impact of decreased commodity prices and lower natural gas, NGL and condensate production as well as lower processing margins; and

$3.4 million increase for our Wholesale Propane Logistics segment as a result of increased per unit margins; partially offset by

$0.6 million decrease for our NGL Logistics segment, primarily attributable to decreased throughput, as well as a decline in volumes from connected plants.

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Operating and Maintenance Expense Operating and maintenance expense decreased in 2009 compared to 2008, primarily as a result of our cost reduction initiatives, partially offset by increased expenses as a result of the MPP acquisition in our Natural Gas Services segment.

General and Administrative Expense General and administrative expense decreased in 2009 compared to 2008, primarily as a result of our cost reduction initiatives, partially offset by the MPP acquisition.

Earnings from Equity Method Investments Earnings from equity method investments decreased in 2009 compared to 2008, primarily due to decreased equity earnings from Discovery of $3.6 million.

Noncontrolling Interest in Income Noncontrolling interest in income represents the noncontrolling interest holders portion of the net income of East Texas, our Collbran Valley Gas Gathering system joint venture, and in 2009 the noncontrolling interest holders portion of the net income of Jackson Pipeline Company, acquired in the MPP acquisition during 2008.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2009 compared to 2008, primarily as a result of the MPP acquisition and our East Texas expansion project.

Six Months Ended June 30, 2009 vs. Six Months Ended June 30, 2008

Total Operating Revenues Total operating revenues decreased in 2009 compared to 2008, primarily due to the following:

- $459.3 million decrease primarily attributable to decreased commodity prices and a decrease in transport volumes, partially offset by a January 1, 2009 amendment to a contract with an affiliate such that our sales to the affiliate are no longer associated with our purchases from the affiliate, which resulted in a prospective change in certain Pelico revenues from a net presentation to a gross presentation, for our Natural Gas Services segment; and

- $116.4 million decrease primarily attributable to lower propane prices, partially offset by increased sales volumes driven by an increase in spot sales, for our Wholesale Propane Logistics segment;

- $1.3 million decrease due to decreased throughput volumes resulting from ethane rejection at certain connected processing plants during the first quarter and lower commodity prices in our NGL Logistics segment; partially offset by

- $185.3 million increase related to commodity derivative activity, resulting from the following:

  - a loss of $38.9 million in 2009 and a loss of $224.4 million in 2008, resulting in a decrease in losses of $185.5 million, which is included in losses from commodity derivative activity. This decrease in losses includes a decrease in unrealized gains of $145.0 million due to forward prices of commodities generally being lower in 2009 compared to 2008 and an increase in realized cash settlement gains of $40.5 million due to average prices of commodities generally being lower in 2009 compared to 2008; partially offset by

  - a $0.2 million increase in unrealized loss, which is included in sales of natural gas, NGLs and condensate; and

- $4.5 million increase in transportation processing and other revenue, primarily attributable to the MPP acquisition in our Natural Gas Services segment.

Gross Margin Gross margin increased in 2009 compared to 2008, primarily due to the following:

$105.8 million increase for our Natural Gas Services segment primarily due to increases related to commodity derivative activity and the MPP acquisition, partially offset by the impact of decreased commodity prices and lower natural gas, NGL and condensate production as well as lower processing margins; and

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$20.6 million increase for our Wholesale Propane Logistics segment as a result of increased per unit margins, approximately $6.0 million of which was attributable to the sale of inventory that was written down at the end of the fourth quarter of 2008, as well as increased volumes; partially offset by

$1.2 million decrease for our NGL Logistics segment, primarily attributable to decreased throughput volumes resulting from ethane rejection at certain connected processing plants during the first quarter, as well as a decline in volumes from connected plants and lower commodity prices.

Operating and Maintenance Expense Operating and maintenance expense decreased in 2009 compared to 2008, primarily as a result of our cost reduction initiatives, partially offset by increased expenses as a result of the MPP acquisition in our Natural Gas Services segment.

General and Administrative Expense General and administrative expense increased in 2009 compared to 2008, primarily as a result of the MPP acquisition, partially offset by our cost reduction initiatives.

*Earnings from Equity Method Investment*s Earnings from equity method investments decreased in 2009 compared to 2008, primarily due to the impact of hurricanes and lower per unit margins on Discovery. Settlements related to our commodity derivatives on our equity method investments are included in segment gross margin.

Noncontrolling Interest in Income Noncontrolling interest in income represents the noncontrolling interest holders portion of the net income or loss of our East Texas, Collbran Valley Gas Gathering system joint venture and in 2009 the noncontrolling interest holders portion of the net income of Jackson Pipeline Company, acquired in the MPP acquisition.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2009 compared to 2008, primarily as a result of the MPP acquisition and our East Texas expansion project.

Results of Operations — Natural Gas Services Segment

This segment consists of our Northern Louisiana system, the Southern Oklahoma system, a 40% limited liability company interest in Discovery, our Colorado and Wyoming systems, our East Texas systems, and our Michigan systems acquired in October 2008.

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2009 vs. 2008		Variance Six Months 2009 vs. 2008	
	2009 (a)	2008 (b)	2009 (a)(b)	2008 (b)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of natural gas, NGLs and condensate	$ 126.5	$ 414.4	$ 250.2	$ 709.7	$ (287.9)	(69)%	$ (459.5)	(65)%
Transportation, processing and other	22.6	18.1	41.7	35.9	4.5	25%	5.8	16%
Losses from commodity derivative activity (c)	(45.8)	(185.2)	(38.8)	(223.3)	(139.4)	(75)%	(184.5)	(83)%
Total operating revenues	103.3	247.3	253.1	522.3	(144.0)	(58)%	(269.2)	(52)%
Purchases of natural gas and NGLs	106.7	353.7	216.1	591.1	(247.0)	(70)%	(375.0)	(63)%
Segment gross margin (d)	(3.4)	(106.4)	37.0	(68.8)	103.0	97%	105.8	*
Operating and maintenance expense	(14.5)	(16.4)	(27.7)	(31.5)	(1.9)	(12)%	(3.8)	(12)%
Depreciation and amortization expense	(15.4)	(12.4)	(29.3)	(24.4)	3.0	24%	4.9	20%
Earnings from equity method investment (e)	3.3	6.9	1.8	17.2	(3.6)	(52)%	(15.4)	(90)%
Segment net loss	(30.0)	(128.3)	(18.2)	(107.5)	98.3	77%	89.3	83%
Segment net income attributable to noncontrolling interests	(2.1)	(13.3)	(0.8)	(27.0)	(11.2)	(84)%	(26.2)	(97)%
Segment net loss attributable to partners	$ (32.1)	$ (141.6)	$ (19.0)	$ (134.5)	$ 109.5	77%	$ 115.5	86%
Operating data:								
Natural gas throughput (MMcf/d) (d)	1,108	980	1,051	980	128	13%	71	7%
NGL gross production (Bbls/d) (d)	28,584	30,659	25,208	31,702	(2,075)	(7)%	(6,494)	(20)%

* Percentage change is not meaningful.

(a) Includes the results of MPP since October 1, 2008, the date of acquisition.

(b) In April 2009, we completed the acquisition of an additional 25.1% interest in East Texas from DCP Midstream, LLC, which results in us owning a 50.1% interest in East Texas. Prior to this transaction, we accounted for our interest in East Texas under the equity method of accounting. As a result of our owning in excess of 50%, and because the transaction was between entities under common control, we are required to present results of operations, including all historical periods, on a consolidated basis. Therefore, these results as presented are different from those originally reported in 2008, which excluded the impact of this transaction.

Additionally, note that while we utilize commodity derivative instruments to help stabilize distributable cash flows for our ownership in East Texas as well as all other natural gas services assets, the portion of East Texas owned by DCP Midstream, LLC is unhedged. As such, our consolidated results depict 75% of East Texas unhedged in all periods prior to the second quarter of 2009 and 49.9% of East Texas unhedged for all periods subsequent to the first quarter of 2009.

Our gross margin for our Natural Gas Services segment changed from a loss of $146.2 million and $148.7 million as previously reported in 2008, to a loss of $106.4 million and $68.8 million as currently reported, for the three and six months ended June 30, 2008, respectively.

(c) Includes the effect of the acquisition of the NGL Hedge, contributed by DCP Midstream, LLC in April 2009. The NGL Hedge is a fixed price natural gas liquids derivative by NGL component for the period April 2009 to March 2010.

(d) Gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas and NGLs. Please read How We Evaluate Our Operations above.

(e) Includes our proportionate share of the throughput volumes and NGL production of Collbran, Jackson East Texas and Discovery and our proportionate share of the earnings of Discovery for each period presented. Earnings for Discovery include the amortization of the net difference between the carrying amount of the investment and the underlying equity of the investment.

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Three Months Ended June 30, 2009 vs. Three Months Ended June 30, 2008

Total Operating Revenues Total operating revenues decreased in 2009 compared to 2008, primarily due to the following:

- $233.5 million decrease attributable to decreased commodity prices;
- $54.5 million decrease, primarily due to a decrease in transport volumes and, partially offset by a January 1, 2009 amendment to a contract with an affiliate such that certain Pelico revenues changed from a net presentation to a gross presentation; partially offset by
- $139.5 million increase related to commodity derivative activity, resulting from the following:
  - a loss of $45.8 million in 2009 and a loss of $185.2 million in 2008, resulting in a decrease in losses of $139.4 million, which is included in losses from commodity derivative activity. This decrease in losses includes a decrease in unrealized losses of $116.1 million due to forward prices of commodities generally being lower in 2009 compared to 2008, and an increase in realized cash settlement gains of $23.3 million due to average prices of commodities generally being lower in 2009 compared to 2008; and
  - a $0.1 million decrease in unrealized loss, which is included in sales of natural gas, NGLs and condensate;
- $4.5 million increase in transportation, processing and other revenue, primarily as a result of the MPP acquisition.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs decreased in 2009 compared to 2008, primarily due to lower costs of natural gas supply, driven by lower commodity prices, partially offset by an amendment to a contract with an affiliate, which resulted in a prospective change in certain Pelico purchases from a net presentation to a gross presentation.

Segment Gross Margin Segment gross margin increased in 2009 compared to 2008, primarily as a result of the following:

- $139.5 million increase related to commodity derivative activity, as discussed in the Operating Revenues section above; and
- $5.0 million increase primarily as a result of the MPP acquisition; partially offset by
- $34.1 million decrease due to lower commodity prices; and
- $7.4 million decrease due to lower natural gas volumes and NGL production, as well as lower processing margins.

Operating and Maintenance Expense Operating and maintenance expense decreased in 2009 compared to 2008, primarily as a result of our cost reduction initiatives, partially offset by increased expenses as a result of the MPP acquisition.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2009 compared to 2008, primarily as a result of the MPP acquisition and our East Texas expansion project.

Earnings from Equity Method Investment Earnings from equity method investment decreased in 2009 compared to 2008, primarily due to the impact of lower per-unit margins on Discovery. Settlements related to our commodity derivatives on our equity method investment are included in segment gross margin. Decreased equity earnings were primarily as a result of the following variances, representing 100% of the earnings drivers for Discovery: a decrease in Discovery s net income of $7.6 million, due primarily to $12.0 million lower NGL sales margins resulting from lower average per-unit margins on higher volumes. These decreases were partially offset by $2.0 million lower depreciation and accretion expense and $1.8 million lower operating and maintenance expense.

Noncontrolling Interest in Income Noncontrolling interest in income represents the noncontrolling interest holders portion of the net income of our East Texas, Collbran Valley Gas Gathering system joint venture and in 2009 the noncontrolling interest holders portion of the net income of Jackson Pipeline Company, acquired in the MPP acquisition.

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Natural gas transported, processed and/or treated increased in 2009 compared to 2008, due primarily to increased volumes from the MPP acquisition, partially offset by decreased volumes across our Northern Louisiana system, as well as at East Texas and Discovery. NGL production decreased in 2009 compared to 2008, due primarily to decreased NGL production at East Texas.

Six Months Ended June 30, 2009 vs. Six Months Ended June 30, 2008

Total Operating Revenues Total operating revenues decreased in 2009 compared to 2008, primarily due to the following:

- $369.2 million decrease attributable to decreased commodity prices;
- $90.1 million decrease in transport volumes, partially offset by a January 1, 2009 amendment to a contract with an affiliate such that certain Pelico revenues changed from a net presentation to a gross presentation; partially offset by
- $184.3 million increase related to commodity derivative activity, resulting from the following:
  - a loss of $38.8 million in 2009 and a loss of $223.3 million in 2008, resulting in a decrease in losses of $184.5 million, which is included in losses from commodity derivative activity. This increase includes a decrease in unrealized losses of $147.4 million due to forward prices of commodities generally being lower in 2009 compared to 2008, and an increase in realized cash settlement gains of $37.1 million due to average prices of commodities generally being lower in 2009 compared to 2008; partially offset by
  - a $0.2 million increase in unrealized loss, which is included in sales of natural gas, NGLs and condensate;
- $5.8 million increase in transportation, processing and other revenue, primarily as a result of the MPP acquisition.

Purchases of Natural Gas and NGLs Purchases of natural gas and NGLs decreased in 2009 compared to 2008, primarily due to lower costs of natural gas supply, driven by lower commodity prices, partially offset by an amendment to a contract with an affiliate, which resulted in a prospective change in certain Pelico purchases from a net presentation to a gross presentation.

Segment Gross Margin Segment gross margin increased in 2009 compared to 2008, primarily as a result of the following:

- $184.3 million increase related to commodity derivative activity, as discussed in the Operating Revenues section above; and
- $9.9 million increase primarily as a result of the MPP acquisition, partially offset by lower processing margins; partially offset by
- $60.6 million decrease due to lower commodity prices; and
- $27.8 million decrease due to lower natural gas volumes and NGL production, as well as lower processing margins.

Operating and Maintenance Expense Operating and maintenance expense decreased in 2009 compared to 2008, primarily as a result of our cost reduction initiatives, partially offset by increased expenses as a result of the MPP acquisition.

Depreciation and Amortization Expense Depreciation and amortization expense increased in 2009 compared to 2008, primarily as a result of the MPP acquisition and our East Texas expansion project.

Earnings from Equity Method Investment Earnings from equity method investment decreased in 2009 compared to 2008, primarily due to the impact of lower per-unit margins and hurricanes on Discovery. Settlements related to our commodity derivatives on our equity method investment are included in segment gross margin. Decreased equity earnings were primarily as a result of the following variances, representing 100% of the earnings drivers for Discovery: a decrease in Discovery s net income of $35.7 million due primarily to $35.0 million lower NGL sales margins resulting from lower average per-unit margins and lower volumes on NGL equity sales, combined with $5.2 million unfavorable other income/expense net. These decreases were partially offset by $5.1 million lower depreciation and accretion expense.

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Noncontrolling Interest in Income Noncontrolling interest in income represents the noncontrolling interest holders portion of the net income or loss of our East Texas, Collbran Valley Gas Gathering system joint venture and in 2009 the noncontrolling interest holders portion of the net income of Jackson Pipeline Company, acquired in the MPP acquisition.

Natural gas transported, processed and/or treated increased in 2009 compared to 2008, due primarily to increased volumes from the MPP acquisition, partially offset by decreased volumes across our Northern Louisiana system and East Texas. NGL production decreased in 2009 compared to 2008, due primarily to decreased NGL production at East Texas and Discovery. Decreased production at East Texas was primarily as a result of production being temporarily shut in following a fire resulting from a third party underground pipeline rupture, during the first quarter of 2009.

Results of Operations Wholesale Propane Logistics Segment

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

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2009 vs. 2008		Variance Six Months 2009 vs. 2008	
	2009	2008	2009	2008	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of propane	$ 46.8	$ 95.3	$ 179.6	$ 296.0	$ (48.5)	(51)%	$ (116.4)	(39)%
Other	0.2	1.1	0.2	1.1	(0.9)	(82)%	(0.9)	(82)%
Losses from commodity derivative activity	(0.1)	(2.1)	(0.1)	(1.1)	(2.0)	(95)%	(1.0)	(91)%
Total operating revenues	46.9	94.3	179.7	296.0	(47.4)	(50)%	(116.3)	(39)%
Purchases of propane	41.1	91.9	148.1	285.0	(50.8)	(55)%	(136.9)	(48)%
Segment gross margin (a)	5.8	2.4	31.6	11.0	3.4	142%	20.6	187%
Operating and maintenance expense	(2.4)	(2.7)	(5.1)	(5.4)	(0.3)	(11)%	(0.3)	(6)%
Depreciation and amortization expense	(0.4)	(0.3)	(0.7)	(0.6)	0.1	33%	0.1	17%
Other		1.5		1.5	(1.5)	(100)%	(1.5)	(100)%
Segment net income attributable to partners	$ 3.0	$ 0.9	$ 25.8	$ 6.5	$ 2.1	233%	$ 19.3	297%
Operating data:								
Propane sales volume (Bbls/d)	13,912	14,442	25,502	24,178	(530)	(4)%	1,324	5%

* Percentage change is not meaningful.

(a) Segment gross margin consists of total operating revenues, including commodity derivative activity, less purchases of propane. Please read How We Evaluate Our Operations above.

Three Months Ended June 30, 2009 vs. Three Months Ended June 30, 2008

Total Operating Revenues Total operating revenues decreased in 2009 compared to 2008, primarily due to the following:

$45.0 million decrease attributable to lower propane prices;

$3.5 million decrease attributable to decreased sales volumes; and

$0.9 million decrease attributable to other fee revenue; partially offset by

$2.0 million increase related to commodity derivative activity, which represents a decrease in unrealized losses of $0.1 million recognized in 2008, and a decrease in realized cash settlement losses of $1.9 million recognized in 2008.

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Purchases of Propane Purchases of propane decreased in 2009 compared to 2008, primarily due to decreased per unit prices.

Segment Gross Margin Segment gross margin increased in 2009 compared to 2008, primarily as a result of increased per unit margins and decreased losses related to commodity derivative activity.

Six Months Ended June 30, 2009 vs. Six Months Ended June 30, 2008

Total Operating Revenues Total operating revenues decreased in 2009 compared to 2008, primarily due to the following:

- $132.7 million decrease attributable to lower propane prices;

- $0.9 million decrease attributable to other fee revenue; partially offset by

- $16.3 million increase attributable to increased propane sales volumes, driven by an increase in spot sales during the first quarter;

- $1.0 million increase related to commodity derivative activity, which represents decreased realized cash settlement losses of $3.4 million, partially offset by a decrease in unrealized gains of $2.4 million.

Purchases of Propane Purchases of propane decreased in 2009 compared to 2008, primarily due to decreased per unit prices, partially offset by increased purchase volumes.

Segment Gross Margin Segment gross margin increased in 2009 compared to 2008, primarily as a result of increased per unit margins, approximately $6.0 million of which was attributable to the sale of inventory that was written down at the end of the fourth quarter of 2008, as well as increased volumes and decreases in losses related to commodity derivative activity.

Results of Operations NGL Logistics Segment

This segment includes our Seabreeze and Wilbreeze NGL transportation pipelines and our 45% interest in Black Lake:

	Three Months Ended June 30,		Six Months Ended June 30,		Variance Three Months 2009 vs. 2008		Variance Six Months 2009 vs. 2008	
	2009	2008	2009	2008	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of NGLs	$ 0.4	$ 1.1	$ 1.0	$ 2.3	$ (0.7)	(64)%	$ (1.3)	(57)%
Transportation, processing and other	1.4	1.6	2.6	3.0	(0.2)	(13)%	(0.4)	(13)%
Total operating revenues	1.8	2.7	3.6	5.3	(0.9)	(33)%	(1.7)	(32)%
Purchases of NGLs	0.5	0.8	1.0	1.5	(0.3)	(38)%	(0.5)	(33)%
Segment gross margin (a)	1.3	1.9	2.6	3.8	(0.6)	(32)%	(1.2)	(32)%
Operating and maintenance expense	(0.2)	(0.2)	(0.5)	(0.4)		%	0.1	25%
Depreciation and amortization expense	(0.4)	(0.3)	(0.8)	(0.7)	0.1	33%	0.1	14%
	0.4	0.2	0.8	0.6	0.2	100%	0.2	33%

Earnings from equity method investment (b)								
Segment net income attributable to partners	$ 1.1	$ 1.6	$ 2.1	$ 3.3	$ (0.5)	(31)%	$ (1.2)	(36)%
Operating data:								
NGL pipelines throughput (Bbls/d) (b)	26,850	34,286	25,409	33,081	(7,436)	(22)%	(7,672)	(23)%

* Percentage change is not meaningful.

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

(b) Includes our proportionate share of the throughput volumes and earnings of Black Lake and the amortization of the net difference between the carrying amount of Black Lake and the underlying equity of Black Lake, for each period presented.

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Three Months Ended June 30, 2009 vs. Three Months Ended June 30, 2008

Total Operating Revenues Total operating revenues decreased in 2009 compared to 2008, primarily due to decreased throughput, as well as a decline in volumes from connected plants.

Purchases of NGLs Purchases of NGLs decreased in 2009 compared to 2008, due primarily to decreased throughput volumes and lower commodity prices.

Segment Gross Margin Segment gross margin decreased in 2009 compared to 2008, primarily die to decreased throughput volumes, as well as a decline in volumes from connected plants.

Six Months Ended June 30, 2009 vs. Six Months Ended June 30, 2008

Total Operating Revenues Total operating revenues decreased in 2009 compared to 2008, primarily due to decreased throughput volumes resulting from ethane rejection at certain connected processing plants during the first quarter of 2009 and lower commodity prices, as well as a decline in volumes from connected plants.

Purchases of NGLs Purchases of NGLs decreased in 2009 compared to 2008, due primarily to decreased throughput volumes resulting from ethane rejection at certain connected processing plants during the first quarter of 2009 and lower commodity prices.

Segment Gross Margin Segment gross margin decreased in 2009 compared to 2008, primarily due to decreased throughput volumes resulting from ethane rejection at certain connected processing plants during the first quarter of 2009 and lower commodity prices, as well as a decline in volumes from connected plants.

Liquidity and Capital Resources

We expect our sources of liquidity to include:

- cash generated from operations;
- cash distributions from our equity method investments;
- borrowings under our revolving credit facility;
- cash realized from the liquidation of securities that are pledged under our term loan facility;
- issuance of additional partnership units;
- debt offerings;
- guarantees issued by DCP Midstream, LLC, which reduce the amount of collateral we may be required to post with certain counterparties to our commodity derivative instruments; and

letters of credit.

We anticipate our more significant uses of resources to include:

- capital expenditures;
- quarterly distributions to our unitholders;
- contributions to our equity method investments to finance our share of their capital expenditures;
- business and asset acquisitions; and

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collateral with counterparties to our swap contracts to secure potential exposure under these contracts, which may, at times, be significant depending on commodity price movements, and which is required to the extent we exceed certain guarantees issued by DCP Midstream, LLC and letters of credit we have posted.

We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements, long-term capital expenditure and acquisition requirements, and quarterly cash distributions for the next twelve months. In the event these sources are not sufficient, we would reduce our discretionary spending.

Beginning in the third quarter of 2008, the capital markets experienced volatility, uncertainty and interventions by various governments around the globe. The effects of these market conditions include significant changes in the valuation of equity securities and overnight and longer-term borrowing rates. The availability of credit through traditional sources of funding such as the commercial paper, bank lending and the private and public placement debt markets also decreased dramatically. In these market conditions, it is uncertain if we would be successful in obtaining timely additional funding from the traditional equity or debt markets if it were needed. Furthermore, the cost of such new funding could substantially exceed the cost of funds previously obtained. Based on current and anticipated levels of operations, we believe we have adequate committed financial resources to conduct our business, although deterioration in our operating environment beyond that currently anticipated could limit our borrowing capacity, as well as impact our compliance with our financial covenant requirements under our credit agreement.

Changes in natural gas, NGL and condensate prices and the terms of our processing arrangements have a direct impact on our generation and use of cash from operations due to their impact on net income, along with the resulting changes in working capital. We have mitigated a significant portion of our anticipated commodity price risk associated with the equity volumes from our gathering and processing activities through 2014 with fixed price natural gas, crude oil and NGL swaps. For additional information regarding our derivative activities, please read Item7A. Quantitative and Qualitative Disclosures about Market Risk in our 2008 Form 10-K and Item 3. Quantitative and Qualitative Disclosures about Market Risk in this Quarterly Report on Form 10-Q.

Our banking group is comprised of various financial institutions, of which certain institutions have recently merged. We do not expect the aggregate contractual financial commitment of these institutions to us to change during the remaining life of our existing credit agreement as a result of these mergers.

We have a 5-year credit agreement, or the Credit Agreement, consisting of a $789.6 million revolving credit facility and a $35.0 million term loan facility at June 30, 2009. These amounts are net of non-participation by Lehman Brothers Commercial Bank. Our borrowing capacity may be limited by the Credit Agreement s financial covenant requirements. Except in the case of a default, which would make the borrowings under the Credit Agreement fully callable, amounts borrowed under the Credit Agreement will not mature prior to the June 21, 2012 maturity date. As of August 3, 2009, we had approximately $221.3 million of borrowing capacity under the Credit Agreement.

The counterparties to each of our commodity swap contracts are investment-grade rated financial institutions. Under these contracts, we may be required to provide collateral to the counterparties in the event that our potential payment exposure exceeds a predetermined collateral threshold. Collateral thresholds are set by us and each counterparty, as applicable, in the master contract that governs our financial transactions based on our and the counterparty s assessment of creditworthiness. The assessment of our position with respect to the collateral thresholds are determined on a counterparty by counterparty basis, and are impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative crude oil and natural gas forward price curves, it is not practical to determine a single pricing point at which our swap contracts will meet the collateral thresholds as we may transact multiple commodities with the same counterparty. As of August 3, 2009 DCP Midstream, LLC had issued and outstanding parental guarantees totaling $83.0 million to certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with these counterparties. We pay DCP Midstream LLC a fee of 0.5% per annum on $40.0 million of these parental guarantees. The fee on the remaining parental guarantees of $43.0 million, which were provided prior to our initial public offering, is covered under the omnibus agreement with DCP Midstream, LLC. As of August 3, 2009 we had a letter of credit of $10.0 million, on which we pay a fee of 0.8% per annum. These parental guarantees and letter of credit reduce the amount of cash we may be required to post as collateral. This letter of credit was issued directly by a financial institution and does not reduce the available capacity under our credit facility. As of August 3, 2009, we had no cash collateral posted with counterparties. Depending on daily commodity prices, the amount of collateral posted can go up or down on a daily basis. Predetermined collateral thresholds for commodity derivative instruments guaranteed by DCP Midstream, LLC are generally dependent on DCP Midstream, LLC s credit rating and the thresholds would be reduced to $0 in the event DCP Midstream, LLC s credit rating were to fall below investment grade.

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If we were to have an event of default, of any covenant to our credit agreement, that occurs and is continuing, our International Swap Dealers Association, or 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. For example, if we were to fail to make a required interest or principal payment on a debt instrument, above a predefined threshold level, and after giving effect to any applicable notice or grace period as defined in the ISDA, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative positions.

Working Capital Working capital is the amount by which current assets exceed current liabilities. Current assets are reduced by our quarterly distributions, which are required under the terms of our partnership agreement based on Available Cash, as defined in the partnership agreement. In general, our working capital is impacted by changes in the prices of commodities that we buy and sell, along with other business factors that affect our net income and cash flows. Our working capital is also impacted by the timing of operating cash receipts and disbursements, borrowings of and payments on debt, capital expenditures, and increases or decreases in restricted investments and other long-term assets.

As of June 30, 2009, we had $4.6 million in cash and cash equivalents. Of this balance, as of June 30, 2009, $3.4 million was held by subsidiaries we do not wholly own, which we consolidate in our financial results. Other than the cash held by these subsidiaries, this cash balance was available for general corporate purposes.

We had a working capital deficit of $8.6 million and working capital of $52.2 million as of June 30, 2009 and December 31, 2008, respectively. Excluding derivative working capital liabilities of $19.8 million and $2.3 million, working capital would be $11.2 million and $54.5 million as of June 30, 2009 and December 31, 2008, respectively. The changes in working capital are primarily attributable to the factors described above. We expect that our future working capital requirements will be impacted by these same factors.

Cash Flow Operating, investing and financing activities were as follows:

	Six Months Ended June 30,	
	2009	2008
	(Millions)	
Net cash provided by operating activities	$ 51.3	$ 70.8
Net cash used in investing activities	$ (99.0)	$ (164.0)
Net cash (used in) provided by financing activities	$ (9.6)	$ 90.3

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

We received net cash for settlements of our commodity derivative instruments during the six months ended June 30, 2009 totaling $14.4 million, approximately $3.9 million of which was associated with rebalancing our portfolio. We paid net cash for settlements of our commodity derivative instruments during the six months ended June 30, 2008 totaling $26.1 million.

We received cash distributions from equity method investments of $3.0 million and $21.8 million during the six months ended June 30, 2009 and 2008, respectively. Distributions exceeded earnings by $0.4 million and $4.0 million for the six months ended June 30, 2009 and 2008, respectively.

Net Cash Used in Investing Activities Net cash used in investing activities during the six months ended June 30, 2009 was comprised of: (1) capital expenditures of $118.4 million (our portion of which was $51.4 million and the noncontrolling interest holders portion was $67.0 million), which primarily consisted of expenditures for installation of compression and expansion of our East Texas system, our Collbran system, and the completion of pipeline integrity system upgrades to our Douglas system; (2) investments in Discovery of $5.8 million; and (3) a net payment of $0.1 million related to our acquisition of MPP partially offset by (4) net proceeds from sale of available-for-sale securities of $25.0 million; and (5) proceeds from sale of assets of $0.3 million.

Net cash used in investing activities during the six months ended June 30, 2008, was primarily used for: (1) capital expenditures of $31.2 million, which generally consisted of expenditures for construction and expansion of our infrastructure in addition to well connections and other upgrades to our existing facilities; (2) a payment of $10.9 million related to our acquisition of the MEG subsidiaries; (3) investments in Discovery of $1.9 million; and (4) net purchases of available-for-sale securities of $120.0 million.

We invested cash in equity method investments of $5.8 million and $1.9 million during the six months ended June 30, 2009 and 2008, respectively, of which $1.6 million and $1.9 million, respectively, was to fund our share of capital expansion projects, and $4.2 million in 2009 was to fund repairs to Discovery following damage caused by Hurricane Ike in 2008.

Net Cash (Used in) Provided by Financing Activities Net cash used in financing activities during the six months ended June 30, 2009 was comprised of (1) repayments of debt of $86.8 million; (2) distributions to our unitholders and general partner of $40.2 million; and (3) distributions to noncontrolling interests of $4.9 million; partially offset by (4) borrowings of $68.3 million; (5) contributions from non controlling interests of $50.3 million; (6) net changes in advances to predecessor from DCP Midstream, LLC of $3.0 million; and (7) contributions from DCP Midstream, LLC of $0.7 million.

Net cash provided by financing activities during the six months ended June 30, 2008 was comprised of (1) borrowings of $432.0 million; (2) net proceeds from sales of common limited partner units of $132.1 million; (3) contributions from noncontrolling interests of $9.3 million; (4) contributions from DCP Midstream, LLC of $1.9 million, partially offset by; (5) repayments of debt of $402.0 million; (6) distributions to our unitholders and general partner of $35.8 million; (7) distributions to noncontrolling interests of $34.6 million; and (8) net changes in advances from DCP Midstream, LLC relating to our predecessor of $12.6 million.

During the six months ended June 30, 2009, total outstanding indebtedness under our $824.6 million credit agreement, which includes borrowings under our revolving credit facility, our term loan facility and letters of credit issued under the credit agreement, was not less than $638.3 million and did not exceed $656.8 million. The weighted average indebtedness outstanding for the six months ended June 30, 2009 was $650.5 million.

During the six months ended June 30, 2009 we borrowed (1) $43.3 million under our revolving credit facility for general working capital purposes; and (2) $25.0 million under our revolving credit facility to fund partial repayment of our term loan facility; and we repaid $61.8 million under our revolving credit facility and $25.0 million on our term loan facility.

During the six months ended June 30, 2008, we borrowed (1) $252.0 million under our revolving credit facility for general corporate purposes; (2) $30.0 million under our revolving credit facility to fund a partial retirement of our term loan facility; and (3) $150.0 million under our term loan facility; and we repaid $372.0 million on our revolving credit facility and $30.0 million on our term loan facility.

We expect to continue to use cash in financing activities for the payment of distributions to our unitholders and general partner. See Note 9 of the Notes to Condensed Consolidated Financial Statements in Item 1. Financial Statements.

Capital Requirements The midstream energy business can be capital intensive, requiring significant investment to maintain and upgrade existing operations. Our capital requirements have consisted primarily of, and we anticipate will continue to consist of the following:

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

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

We incur capital expenditures for our consolidated entities and our equity method investments. Of the total $118.4 million of capital expenditures for the six months ended June 30, 2009, $51.4 million represents our portion and $67.0 million represents the noncontrolling interest holders portion. We paid a total of $51.4 million and $17.1 million for our portion of capital expenditures during the six months ended June 30, 2009 and 2008, respectively. This was made up of our portion of expansion capital expenditures of $42.5 million and $13.9 million, and our

portion of maintenance capital expenditures of $8.9 million and $3.2 million for the six months ended June 30, 2009 and 2008, respectively. The amounts we paid for our portion, combined with amounts paid from noncontrolling interests (including DCP Midstream, LLC), amount to our consolidated capital expenditures of $118.4 million and $31.2 million during the six months ended June 30, 2009 and 2008, respectively. These amounts do not reflect capital expenditures for our equity method investments.

We anticipate our portion of maintenance capital expenditures will be approximately $7.0 million and our portion of expansion capital expenditures will be approximately $30.0 million for the remainder of 2009. The board of directors may approve additional growth capital during the year, at their discretion.

Collbran Valley Gas Gathering, LLC, or Collbran, completed the construction of approximately 20 miles of 24-inch diameter gathering pipeline, and is currently setting compression and liquids handling facilities to support its Colorado system, located in the Collbran Valley area of the Piceance Basin in western Colorado. We are the operator and 70% owner of Collbran. We have invested approximately $5.6 million in 2008 and $27.0 million on this project during the six months ended June 30, 2009.

During the third quarter of 2008, we announced plans, along with DCP Midstream, LLC, to invest approximately $56.0 million in East Texas to construct a gathering pipeline to support the East Texas system. In May 2009, service was initiated on the pipeline. Our net investment is approximately $12.9 million, which represents 25% of the total cost of the project. Of this total, we spent approximately $1.3 million in 2008 and $10.6 million during the six months ended June 30, 2009.

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

We expect to fund future capital expenditures with restricted investments, funds generated from our operations, borrowings under our credit facility and the issuance of additional partnership units. If these sources are not sufficient, we may reduce our capital spending.

Given our long-term strategy of profitable growth, our long-term objective is to obtain an investment grade credit rating, to increase our available sources to fund capital expenditures.

Cash Distributions to Unitholders Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all Available Cash, as defined in the partnership agreement. We made cash distributions to our unitholders and general partner of $40.2 million during the six months ended June 30, 2009, as compared to $35.3 million for the same period in 2008. We intend to make quarterly distribution payments to our unitholders and general partner to the extent we have sufficient cash from operations after the establishment of reserves.

Description of the Credit Agreement We have a 5-year credit agreement, or the Credit Agreement, consisting of a $789.6 million revolving credit facility and a $35.0 million term loan facility at June 30, 2009. The Credit Agreement matures on June 21, 2012. As of June 30, 2009, the outstanding balance on the revolving credit facility was $603.0 million and the outstanding balance on the term loan facility was $35.0 million.

Our obligations under the revolving credit facility are unsecured, and the term loan facility is secured at all times by high-grade securities, which are classified as restricted investments in the accompanying condensed consolidated balance sheets, in an amount equal to or greater than the outstanding principal amount of the term loan. Any portion of the term loan balance may be repaid at any time, and we would then have access to a corresponding amount of the collateral securities. Upon any prepayment of term loan borrowings, the amount of our revolving credit facility will automatically increase to the extent that the repayment of our term loan facility is made in connection with an acquisition or construction of assets in the midstream energy business. The unused portion of the revolving credit facility may be used for letters of credit. At June 30, 2009 and December 31, 2008, we had outstanding letters of credit issued under the Credit Agreement of $0.3 million.

As of June 30, 2009, the interest rate on our term loan facility was 0.42% and the weighted-average interest rate on our revolving credit facility was 1.03% per annum.

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Total Contractual Cash Obligations and Off-Balance Sheet Obligations

A summary of our total contractual cash obligations as of June 30, 2009, is as follows:

		Payments Due by Period			
	Total	**Remainder of 2009**	**2010-2011 (Millions)**	**2012-2013**	**2014 and Thereafter**
Long-term debt (a)	$ 716.5	$ 13.5	$ 52.2	$ 650.8	$
Operating lease obligations	47.6	6.7	22.3	14.9	3.7
Purchase obligations (b)	664.3	92.7	246.3	212.3	113.0
Other long-term liabilities (c)	9.0		0.9	0.1	8.0
Total	$ 1,437.4	$ 112.9	$ 321.7	$ 878.1	$ 124.7

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

(b) Purchase obligations include $10.9 million of purchase orders for capital expenditures and $653.4 million of various non-cancelable commitments to purchase physical quantities of commodities in future periods. For contracts where the price paid is based on an index, the amount is based on the forward market prices at June 30, 2009. Purchase obligations exclude accounts payable, accrued interest payable and other current liabilities recognized in the condensed consolidated balance sheets. Purchase obligations also exclude current and long-term unrealized losses on derivative instruments included in the condensed consolidated balance sheet, which represent the current fair value of various derivative contracts and do not represent future cash purchase obligations. These contracts may be settled financially at the difference between the future market price and the contractual price and may result in cash payments or cash receipts in the future, but generally do not require delivery of physical quantities of the underlying commodity. In addition, many of our gas purchase contracts include short and long term commitments to purchase produced gas at market prices. These contracts, which have no minimum quantities, are excluded from the table.

(c) Other long-term liabilities include $8.2 million of asset retirement obligations and $0.8 million of environmental reserves recognized in the June 30, 2009 condensed consolidated balance sheet.

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

Recent Accounting Pronouncements

Financial Accounting Standards Board, or FASB, Statement of Financial Accounting Standards, or SFAS, No. 168 The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles a Replacement of FASB Statement No. 162, **or SFAS 168** In June 2009, the FASB issued SFAS 168, which establishes the FASB Accounting Standards Codification, or the Codification, as the source of authoritative U.S. Generally Accepted Accounting Principles, or GAAP. The Codification supersedes all existing non-SEC accounting and reporting standards. This SFAS becomes effective for us for annual and interim periods beginning after September 15, 2009 and will have no affect on our condensed consolidated results of operations, cash flows and financial position as a result of adoption.

SFAS No. 167 Amendments to FASB Interpretation No. 46(R), **or SFAS 167** In June 2009, the FASB issued SFAS 167, which requires entities to perform additional analysis of their variable interest entities and consolidation methods. This SFAS becomes effective for us on January 1, 2010 and we are in the process of assessing the impact of this guidance on our condensed consolidated results of operations, cash flows and financial position.

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***SFAS No. 165 Subsequent Events,* or SFAS 165** In May 2009, the FASB issued SFAS 165, which sets forth the recognition and disclosure requirements for events that occur after the balance sheet date, but before financial statements are issued or are available to be issued. We adopted SFAS 165 effective June 30, 2009, and there was no effect on our condensed consolidated results of operations, cash flows or financial position as a result of adoption. All appropriate disclosure of subsequent events is made within Part 1, Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on form 10-Q.

***SFAS No. 161 Disclosures about Derivative Instruments and Hedging Activities an Amendment of FASB Statement No. 133*, or SFAS 161** In March 2008, the FASB issued SFAS 161, which requires 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 the provisions of SFAS 161 effective January 1, 2009, and have included all required disclosures in this filing. SFAS 161 impacts only disclosures so there was no effect on our condensed consolidated results of operations, cash flows or financial position as a result of adoption.

***SFAS No. 160 Noncontrolling Interests in Consolidated Financial Statements an Amendment of Accounting Research Bulletin No. 51*, or SFAS 160** In December 2007, the FASB issued SFAS 160, 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. SFAS 160 also establishes 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 SFAS 160 effective January 1, 2009, which required retrospective restatement of our condensed consolidated financial statements for all periods presented in this filing. As a result of adoption, we have reclassified our noncontrolling interest on our condensed consolidated balance sheets, from a component of liabilities to a component of equity and have also reclassified net income attributable to noncontrolling interest on our condensed 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 the noncontrolling interest within our condensed consolidated statements of comprehensive income. We also added a rollforward of the noncontrolling interest within our condensed consolidated statements of changes in partners equity and will present this financial statement on a quarterly basis.

***SFAS No. 141(R) Business Combinations (revised 2007)*, or SFAS 141(R)** In December 2007, the FASB issued SFAS 141(R), 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 SFAS 141(R) effective January 1, 2009, and will account for all transactions with closing dates subsequent to adoption in accordance with the provisions of this standard.

***SFAS No. 157 Fair Value Measurements*, or SFAS 157** In September 2006, the FASB issued SFAS 157, which we adopted on January 1, 2008 for all financial assets and liabilities. Pursuant to FASB Staff Position, or FSP, 157-2, the FASB issued a partial deferral, ending on December 31, 2008, of the implementation of SFAS 157 as it relates to all nonfinancial assets and liabilities where fair value is the required measurement attribute by other accounting standards. Effective January 1, 2009, we adopted SFAS 157 for all nonfinancial assets and liabilities. There was no effect on our condensed consolidated results of operations, cash flows, or financial position, and we have included all required disclosures as a result of the adoption of this standard relative to nonfinancial assets and liabilities. The provisions of SFAS 157 will be applied at such time a fair value measurement of a nonfinancial asset or nonfinancial liability is required, which may result in a fair value that is different than would have been calculated prior to the adoption of SFAS 157.

***FSP No. SFAS 142-3 Determination of the Useful Life of Intangible Assets,* or FSP 142-3** In April 2008, the FASB issued FSP 142-3, which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of an intangible asset. We adopted FSP 142-3 on January 1, 2009. As a result of acquisitions, we have intangible assets for customer contracts and related relationships in our condensed consolidated balance sheets. Generally, costs to renew or extend such contracts are not significant, and are expensed to the condensed consolidated statements of operations as incurred. During the current quarter, there were no contracts that were recognized as intangible assets that were renewed or extended.

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FSP No. SFAS 157-4 Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly, **or FSP 157-4** In April 2009, the FASB issued FSP 157-4, 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 FSP 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. 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 have adopted this FSP as of June 30, 2009 and there was no impact on our condensed consolidated results of operations, cash flows or financial position.

FSP No. SFAS 141(R)-1 Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies, **or FSP 141(R)-1** In April 2009, the FASB issued FSP 141(R)-1, which provides 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 SFAS No. 5 Accounting for Contingencies, or SFAS 5. This FSP emphasizes the guidance set forth in SFAS 141(R) 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 SFAS 5. This FSP becomes effective for us for business combinations with closing dates subsequent to January 1, 2009. During the first two quarters of 2009 we did not have any transactions that were accounted for as business combinations. We will account for any business combinations with closing dates subsequent to the effective date in accordance with this new guidance.

FSP No. SFAS 107-1 and APB 28-1 Interim Disclosures about Fair Value of Financial Instruments This FSP was issued in April 2009, and requires disclosure of summarized financial information for financial instruments accounted for under SFAS No. 107 Disclosures about Fair Value of Financial Instruments, or SFAS 107. We have instruments that are subject to the fair value disclosure requirements of SFAS 107, and are subject to the revised disclosure provisions of this FSP. We have adopted this FSP as of June 30, 2009 and there was no impact on our condensed consolidated results of operations, cash flows or financial position.

FSP No. SFAS 115-2 and SFAS 124-2 Recognition and Presentation of Other-Than-Temporary Impairments This FSP was issued in April 2009, and amends 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 have adopted this FSP as of June 30, 2009 and there was no impact on our condensed consolidated results of operations, cash flows or financial position.

Emerging Issues Task Force, or EITF, 08-6 Equity Method Investment Accounting Considerations**, or EITF 08-6** In November 2008 the EITF issued EITF 08-6. Although the issuance of SFAS 141(R) and SFAS 160 were not intended to reconsider the accounting for equity method investments, the application of the equity method is affected by the issuance of these standards. 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 issue became effective for us on January 1, 2009, and although it has not impacted the manner in which we apply equity method accounting, this guidance will be considered on a prospective basis to transactions with equity method investees.

EITF 07-4 Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships **or EITF 07-4** In March 2008, the EITF issued EITF 07-4. This issue seeks to improve the comparability of earnings per unit, or EPU, calculations for master limited partnerships with incentive distribution rights in accordance with FASB Statement No. 128 and its related interpretations. We adopted EITF 07-4 effective January 1, 2009. As a result of adopting EITF 07-4, 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. EITF 07-4 is 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 loss per LPU increased from \$(5.66) per unit to \$(5.67) per unit and from \$(6.33) per unit to \$(6.36) per unit for the three and six months ended June 30, 2008, respectively.

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

For an in-depth discussion of our market risks, see Item 7A. Quantitative and Qualitative Disclosures about Market Risk in our 2008 Form 10-K.

Credit Risk

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

Interest Rate Risk

Interest rates on future credit facility draws and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Although this could limit our ability to raise funds in the debt capital markets, we expect to remain competitive with respect to acquisitions and capital projects, as our competitors would face similar circumstances.

We mitigate a portion of our interest rate risk with interest rate swaps, which reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. 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. The interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. At June 30, 2009, the effective weighted-average interest rate on our $603.0 million of outstanding revolver debt was 4.47%, taking into account the $575.0 million of indebtedness with designated interest rate swaps.

Based on the annualized unhedged borrowings under our credit facility of $63.0 million as of June 30, 2009, a 0.5% movement in the base rate or LIBOR rate would result in an approximately $0.3 million annualized increase or decrease in interest expense.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of our gathering, processing, sales and storage activities. For gathering services, we receive fees or commodities from producers to bring the natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, depending on the types of contracts. We employ established policies and procedures to manage our risks associated with these market fluctuations using various commodity derivatives, including forward contracts, swaps and futures.

Commodity Cash Flow Protection Activities We closely monitor the risks associated with commodity price changes on our future operations and, where appropriate, use various commodity instruments such as fixed price natural gas, crude oil and NGL contracts to mitigate the effect pricing fluctuations may have on the value of our assets and operations. Depending on our risk management objectives, we may periodically settle a portion of these instruments prior to their maturity.

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We enter into derivative financial instruments to mitigate the risk of weakening natural gas, NGL and condensate prices associated with our percent-of-proceeds arrangements and gathering operations. Historically, there has been a relationship between NGL prices and crude oil prices and lack of liquidity in the NGL financial market; therefore we have historically used crude oil swaps to mitigate NGL price risk. As a result of these transactions, we have mitigated a significant portion of our expected natural gas, NGL and condensate commodity price risk through 2014.

The derivative financial instruments we have entered into are typically referred to as swap contracts. These swap contracts entitle us to receive payment at settlement from the counterparty to the contract to the extent that the reference price is below the swap price stated in the contract, and we are required to make payment at settlement to the counterparty to the extent that the reference price is higher than the swap price stated in the contract.

We are using the mark-to-market method of accounting for all commodity derivative instruments, which has significantly increased the volatility of our results of operations as we recognize, in current earnings, all non-cash gains and losses from the mark-to-market on derivative activity.

The following table sets forth our commodity derivative instruments as of August 3, 2009:

Period	Commodity	Notional Volume	Reference Price	Swap Price Range
July 2009 December 2009	Natural Gas	2,000 MMBtu/d	Texas Gas Transmission Price (a)	$9.20/MMBtu
July 2009 December 2009	Natural Gas	1,500 MMBtu/d	NYMEX Final Settlement Price (b)	$8.22/MMBtu
January 2010 December 2013	Natural Gas	1,000 MMBtu/d	NYMEX Final Settlement Price (b)	$8.22/MMBtu
July 2009 December 2010	Natural Gas	1,634 MMBtu/d	IFERC Monthly Index Price for Colorado Interstate Gas Pipeline (e)	$3.94/MMBtu
January 2011 December 2012	Natural Gas	500/ MMBtu/d	IFERC Monthly Index Prices for Colorado Interstate Gas Pipeline (e)	$5.89/MMBtu
January 2010 December 2010	Natural Gas	1,900 MMBtu/d	Texas Gas Transmission Price (a)	$6.41 -$9.20/MMBtu
January 2011 December 2012	Natural Gas	1,100 MMBtu/d	Texas Gas Transmission Price (a)	$6.41 - $6.80/MMBtu
July 2009 December 2009	Natural Gas Basis	1,500 MMBtu/d	IFERC Monthly Index Price for Panhandle Eastern Pipe Line (c)	NYMEX less $0.68/MMBtu
January 2010 December 2013	Natural Gas Basis	1,000 MMBtu/d	IFERC Monthly Index Price for Panhandle Eastern Pipe Line (c)	NYMEX less $0.68/MMBtu
July 2009 December 2009	Crude Oil	2,450 Bbls/d	Asian-pricing of NYMEX crude oil futures (d)	$63.05 - $86.95/Bbl
January 2010 December 2010	Crude Oil	2,415 Bbls/d	Asian-pricing of NYMEX crude oil futures (d)	$63.05 - $87.25/Bbl
April 2010 December 2011	Crude Oil	250 Bbls/d	Asian-pricing of NYMBEX crude oil futures (d)	$56.75 - $59.30/Bbl
January 2011 December 2011	Crude Oil	2,350 Bbls/d	Asian-pricing of NYMEX crude oil futures (d)	$66.72 - $87.25/Bbl
January 2012 December 2012	Crude Oil	2,125 Bbls/d	Asian-pricing of NYMEX crude oil futures (d)	$66.72 - $90.00/Bbl
January 2013 December 2013	Crude Oil	2,050 Bbls/d	Asian-pricing of NYMEX crude oil futures (d)	$67.60 - $83.00/Bbl
January 2014 December 2014	Crude Oil	1,000 Bbls/d	Asian-pricing of NYMEX crude oil futures (d)	$74.90 - $84.70/Bbl
July 2009 March 2010	NGLs	839 Bbls/d	Mt. Belvieu Non-TET (f)	$0.66 - $1.63/Gal

(a) The Inside FERC index price for natural gas delivered into the Texas Gas Transmission pipeline in the North Louisiana area.
(b) NYMEX final settlement price for natural gas futures contracts (NG).
(c) The Inside FERC monthly published index price for Panhandle Eastern Pipe Line (Texas, Oklahoma mainline) less the NYMEX final settlement price for natural gas futures contracts.
(d) Monthly average of the daily close prices for the prompt month NYMEX light, sweet crude oil futures contract (CL).
(e) The Inside FERC index price for natural gas delivered into the Colorado Interstate Gas (CIG) pipeline.

(f) The average monthly OPIS price for Mt. Belvieu Non-TET.

We utilize crude oil and NGL derivatives to mitigate a significant portion of our commodity price exposure for propane and heavier NGLs. Due to current movements in the relationship of NGL prices to crude oil prices outside of recent historical ranges, we have provided an additional sensitivity factor to capture movements up or down in this relationship. We have combined the NGL and crude oil sensitivities into one factor, and added our sensitivity to changes in the relationship between the pricing of NGLs and crude oil. For fixed price natural gas and crude oil, the sensitivities are associated with our unhedged volumes. For our NGL to crude oil price relationship, the sensitivity is associated with both hedged and unhedged equity volumes. Given our current contract mix and the commodity derivative contracts we have in place, we have updated our annualized sensitivities for 2009 as shown in the table below, which excludes the impact from mark-to-market on our commodity derivatives.

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Commodity Sensitivities Excluding Non-Cash Mark-To-Market

	Per Unit Decrease	Unit of Measurement	Estimated Decrease in Annual Net Income (Millions)
Natural gas prices	$ 1.00	MMBtu	$ 0.1
Crude oil prices (a)	$ 5.00	Barrel	$ 1.4
NGL to crude oil price relationship (b)	5 percentage point change	Barrel	$ 4.3

(a) Assuming 60% NGL to crude oil price relationship.
(b) Assuming 60% NGL to crude oil price relationship and $60.00/Bbl crude oil price. Generally, this sensitivity changes by $1.5 million for each $20.00/Bbl change in the price of crude oil. As crude oil prices increase from $60.00/Bbl, we become slightly more sensitive to the change in the relationship of NGL prices to crude oil prices. As crude oil prices decrease from $60.00/Bbl, we become less sensitive to the change in the relationship of NGL prices to crude oil prices.

In addition to the linear relationships in our commodity sensitivities above, additional factors cause us to be less sensitive to commodity price declines. A portion of our net income is derived from fee-based contracts and a certain percentage of liquids processing arrangements that contain minimum fee clauses in which our processing margins convert to fee-based arrangements as NGL prices decline.

The above sensitivities exclude the impact from arrangements where producers on a monthly basis may elect to not process their natural gas in which case we retain a portion of the customers natural gas in lieu of NGLs as a fee. The above sensitivities also exclude certain related processing arrangements where we control the processing or by-pass of the production based upon individual economic processing conditions. Under each of these types of arrangements, our processing of the natural gas would yield favorable processing margins. Less than 10% of our gas throughput is associated with these arrangements.

We estimate the following non-cash sensitivities in 2009 related to the mark-to-market on our commodity derivatives associated with our commodity cash flow protection activities:

Non-Cash Mark-To-Market Commodity Sensitivities

	Per Unit Increase	Unit of Measurement	Estimated Mark-to-Market Impact (Decrease in Net Income) (Millions)
Natural gas prices	$ 1.00	MMBtu	$ 4.5
Crude oil prices	$ 5.00	Barrel	$ 20.7
NGL prices	$ 0.10	Gallon	$ 1.0

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

The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by the prevailing price of NGLs, which in turn has been generally related to the price of crude oil, except in recent periods, when NGL pricing has been at a greater discount to crude oil pricing. Although the prevailing price of residue natural gas has less short-term significance to our operating results than the price of NGLs, in the long term, the growth and sustainability of our business depends on natural gas prices being at levels sufficient to provide incentives and capital, for producers to increase natural gas exploration and production. To minimize potential future commodity-based pricing and cash flow volatility, we have entered into a series of derivative financial instruments. As a result of these transactions, we have mitigated a significant portion of our

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expected natural gas, NGL and condensate commodity price risk relating to the equity volumes associated with our gathering and processing activities through 2014. Given the historical relationship between NGL prices and crude oil prices and lack of liquidity in the NGL financial market, we have generally used crude oil swaps to mitigate NGL price risk. As a result of the current movements in the relationship of NGL prices to crude oil prices outside of recent historical ranges, we have additional exposure to changes in the relationship.

Based on historical trends, however, we generally expect NGL prices to follow changes in crude oil prices over the long term, which we believe will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy. We believe that future natural gas prices will be influenced by supply deliverability, the severity of winter and summer weather, and the domestic production and drilling activity level of exploration and production companies. Drilling activity can be adversely affected as natural gas prices decrease. Energy market uncertainty could also reduce North American drilling activity in the future. Limited access to capital could also decrease drilling. Lower drilling levels over a sustained period would have a negative effect on natural gas volumes gathered and processed, but would likely increase commodity prices.

Item 4. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

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

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the six months ended June 30, 2009 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

Except for the two matters noted below, the information required for this item is provided in Note 17, Commitments and Contingent Liabilities, included in Item 8 of our 2008 Form 10-K, which information is incorporated by reference into this item.

Anderson Gulch In February 2009, the Colorado Department of Public Health and Environment, or CDPHE, issued a Notice of Violation that alleges violations of the environmental permit at our Anderson Gulch gas plant in 2008. The Anderson Gulch gas plant is owned by Collbran Valley Gas Gathering, LLC, our 70% owned joint venture in western Colorado. We have negotiated a resolution of this matter with the CDPHE for approximately $186,000, which will consist of a monetary penalty and an agreement to perform a supplemental environmental project.

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. 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, which includes periods of time prior to our ownership of this asset. Our responsibility for this judgment will be limited to the time period after we acquired the asset from DCP Midstream, LLC in December 2005. During the second quarter of 2009 we filed an appeal in the 14th Court of Appeals, Texas and will continue to defend ourselves vigorously against this claim. El Paso has filed an additional lawsuit in Louisiana, claiming damages for the same claims as the Texas matter, but for periods prior to our ownership of the asset. We intend to file motions to remove us from the Louisiana matter. As a result of the jury verdict we recorded a contingent liability of $2.5 million in the fourth quarter of 2008 for this matter, which is included in other long-term liabilities in the condensed consolidated balance sheets as of June 30, 2009 and in other current liabilities in the condensed consolidated balance sheets as of December 31, 2008.

Item 1A. ***Risk Factors***

In addition to the other information set forth in this report, careful consideration should be given to the risk factors discussed in Part I, Item 1A. Risk Factors in our 2008 Form 10-K. An investment in our securities involves various risks. When considering an investment in us, you should consider carefully all of the risk factors described in our 2008 Form 10-K. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may also materially adversely affect our condensed consolidated results of operations, financial condition and cash flows.

The following are new or modified risk factors that should be read in conjunction with the risk factors disclosed in our 2008 Form 10-K:

Because of the natural decline in production from existing wells, our success depends on our ability to obtain new sources of supplies of natural gas and NGLs.

Our gathering and transportation pipeline systems are connected to or dependent on the level of production from natural gas wells, from which production will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our gathering and transportation pipeline systems and NGL pipelines and the asset utilization rates at our natural gas processing plants, we must continually obtain new supplies. The primary factors affecting our ability to obtain new supplies of natural gas and NGLs, and to attract new customers to our assets, include the level of successful drilling activity near these assets, the demand for natural gas and crude oil, producers desire and ability to obtain necessary permits in an efficient manner, natural gas field characteristics and production performance, surface access and infrastructure issues, and our ability to compete for volumes from successful new wells. If we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells or because of competition, throughput on our pipelines and the utilization rates of our treating and processing facilities would decline, which could have a material adverse effect on our business, results of operations, financial position and cash flows.

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Recent commodity price erosion, the credit market crisis and the current economic conditions may adversely affect natural gas and NGL producers drilling activity and transportation spending levels, which may in turn negatively impact our volumes and results of operations and our ability to make distributions to our unitholders.

The level of drilling activity is dependent on economic and business factors beyond our control. Among the factors that impact drilling decisions are natural gas prices and the deterioration generally of the credit and financial markets. Natural gas prices are lower in recent periods when compared to historical periods. For example, the rolling twelve-month average New York Mercantile Exchange, or NYMEX, daily settlement price of natural gas futures contracts per MMBtu was $5.10 as of June 30, 2009, $4.83 as of March 31, 2009 and was $6.21, $7.96 and $7.23 as of December 31, 2008, 2007 and 2006, respectively. During periods of natural gas price decline, in particular in periods when capital markets are experiencing severe strain as in the current economy, the level of drilling activity could decrease. Suppliers which finance their drilling activities through cash flow from operations, the incurrence of debt or the issuance of equity may not be able or willing to do so under current market conditions, which continue to demonstrate a decline from prior periods in credit availability and a reduction in equity values. When combined with a reduction of cash flow resulting from recent declines in natural gas prices, a reduction in our producers borrowing base under reserve-based credit facilities and lack of availability of debt or equity financing for our producers may result in a significant reduction in our producers spending for natural gas drilling activity, which could result in lower volumes being transported on our pipeline systems.

Furthermore, a sustained decline in natural gas prices could result in a decrease in exploration and development activities in the fields served by our gathering and pipeline transportation systems and our natural gas treating and processing plants, which could lead to reduced utilization of these assets. For example, exploration and production companies have announced that the depressed natural gas prices may lead to reduced capital expenditures in 2009, which could lead them to shut-in wells and reduce production. Other factors that impact production decisions include the ability of producers to obtain necessary drilling and other governmental permits and regulatory changes. Because of these factors, even if new natural gas reserves are discovered in areas served by our assets, producers may choose not to develop those reserves. If we are not able to obtain new supplies of natural gas to replace the declines due to reductions in drilling activity, throughput on our pipelines and the utilization rates of our treating and processing facilities would decline, which could have a material adverse effect on our business, results of operations, financial position and cash flows, and ability to make cash distributions.

Restrictions in our credit facility may limit our ability to make distributions to unitholders and may limit our ability to capitalize on acquisitions and other business opportunities.

Our credit facility contains covenants limiting our ability to make distributions, incur indebtedness, grant liens, make acquisitions, investments or dispositions and engage in transactions with affiliates. Furthermore, our credit facility contains covenants requiring us to maintain certain leverage and other financial ratios and tests. Any subsequent replacement of our credit facility or any new indebtedness could have similar or greater restrictions. If our covenants are not met, whether as a result of reduced production levels of natural gas and NGLs as described above or otherwise, our financial condition, results of operations and ability to make distributions to our unitholders could be materially adversely affected.

Our assets and operations can be affected by weather and other weather related conditions.

Our assets and operations can be adversely affected by hurricanes, floods, tornadoes, wind, lightening and other natural phenomena, which could impact our results of operations and make it more difficult for us to realize historic rates of return. Although we carry insurance on our assets, insurance may be inadequate to cover our loss and in some instances, we may be unable to obtain insurance on commercially reasonable terms, if at all. If we incur a significant disruption in our operations or a significant liability for which we were not fully insured, our financial condition, results of operations and ability to make distributions to our unitholders could be materially adversely affected.

We may incur significant costs in the future associated with proposed climate change legislation.

The United States Congress and some states where we have operations are currently considering legislation related to greenhouse gas emissions. In addition, there have recently been international conventions and efforts to establish standards for the reduction of greenhouse gases globally. The United States Congress is currently considering a number of bills that would compel carbon dioxide emission reductions. Some of these proposals include limitations, or caps, on the amount of greenhouse gas that can be emitted, as well as a system of emissions allowances. The current proposal in the United States Congress places the entire burden of obtaining allowances for the carbon content of natural gas liquids, or NGLs, on the midstream natural gas industry. To

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the extent legislation is enacted that regulates greenhouse gas emissions, it could significantly increase our costs to (i) acquire allowances; (ii) operate and maintain our facilities; (iii) install new emission controls; and (iv) manage a greenhouse gas emissions program. If such legislation becomes law in the United States or any states we have operations and we are unable to pass these costs through as part of our services, it could have an adverse affect on our business and cash available for distributions.

Item 6. Exhibits *Exhibits*

Exhibit Number	Description
3.1 *	First Amended and Restated Agreement of Limited Partnership of DCP Midstream GP, LP (attached as Exhibit 3.4 to DCP Midstream Partners, LP s Amendment No. 2 to Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on November 18, 2005).
3.2 *	First Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC (attached as Exhibit 3.6 to DCP Midstream Partners, LP s Amendment No. 2 to Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on November 18, 2005).
3.3 *	Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP (attached as Exhibit 3.1 to DCP Midstream Partners, LP s Form 8-K (File No. 001-32678) filed with the SEC on November 7, 2006).
3.4 *	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated as of January 20, 2009 and Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated December 7, 2005 (attached as Exhibit 3.1 to DCP Midstream Partners, LP s Form 10-K (File No. 001-32678) filed with the SEC on March 5, 2009).
3.5 *	Amendment No. 2 to the Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP (attached as Exhibit 3.1 to DCP Midstream Partners, LP s Form 8-K (File No. 001-32678) filed with the SEC on April 7, 2009).
3.6 *	Partnership Agreement Amendment, dated April 1, 2009, entered into by DCP Midstream GP, LP (attached as Exhibit 3.1 to DCP Midstream Partners LP s Form 8-K (File No. 001-32678) filed with the SEC on April 7, 2009)
10.1 *	Omnibus Agreement, dated December 7, 2005, among Duke Energy Field Services, LLC, DCP Midstream GP, LLC, DCP Midstream Partners, LP and DCP Midstream Operating, LP (attached as Exhibit 10.4 to DCP Midstream Partners, LP s Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
10.2 *	DCP Midstream Partners, LP Long-Term Incentive Plan (attached as Exhibit 10.2 to DCP Midstream Partners, LP s Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
10.3 *	Contribution, Conveyance and Assumption Agreement, dated December 7, 2005, among DCP Midstream Partners, LP, DCP Midstream Operating LP, DCP Midstream GP, LLC, DCP Midstream GP, LP, Duke Energy Field Services, LLC, DEFS Holding 1, LLC, DEFS Holding, LLC, DCP Assets Holdings, LP, DCP Assets Holdings, GP, LLC, Duke Energy Guadalupe Pipeline Holdings, Inc., Duke Energy NGL Services, LP, DCP LP Holdings, LP and DCP Black Lake Holdings, LLC (attached as Exhibit 10.3 to DCP Midstream Partners, LP s Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
10.4 *	Natural Gas Gathering Agreement, dated June 1, 1987, as amended, between DEFS Assets Holding, LP, successor to the interest of Cornerstone Natural Gas Company and ConocoPhillips, successor to the interest of Phillips Petroleum Company (attached as Exhibit 10.5 to DCP Midstream Partners, LP s Amendment No. 2 to Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on November 18, 2005).
10.5 *	First Amendment to Omnibus Agreement, dated April 1, 2006, among Duke Energy Field Services, LLC, DCP Midstream GP, LLC, DCP Midstream Partners, LP and DCP Midstream Operating, LP (attached as Exhibit 10.6 to DCP Midstream Partners, LP s Form 10-Q (File No. 001-32678) filed with the SEC on August 11, 2006).
10.6 *	Contribution Agreement, dated October 9, 2006, between DCP LP Holdings, LP and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP s Form 8-K (File No. 001-32678) filed with the SEC on October 13, 2006).
10.7 *	Second Amendment to Omnibus Agreement, dated November 1, 2006, among Duke Energy Field Services, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP and DCP Midstream Operating, LP (attached as Exhibit 10.2 to DCP Midstream Partners, LP s Form 8-K (File No. 001-32678) filed with the SEC on November 7, 2006).
10.8 *	Purchase and Sale Agreement, dated March 7, 2007, between Anadarko Gathering Company, Anadarko Energy Services Company and DCP Midstream Partners, LP (attached as Exhibit 99.1 to DCP Midstream Partners, LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).

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10.9 *	Bridge Credit Agreement, dated May 9, 2007 among DCP Midstream Operating, LP, DCP Midstream Partners, LP, Wachovia Bank, National Association and Wachovia Capital Markets, LLC (attached as Exhibit 99.2 to DCP Midstream Partners, LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).
10.10 *	Third Amendment to Omnibus Agreement, dated May 9, 2007, among DCP Midstream, LLC (f/k/a Duke Energy Field Services, LLC), DCP Midstream GP, LLC, DCP Midstream Partners, LP, DCP Midstream GP, LP, and DCP Midstream Operating, LP (attached as Exhibit 99.3 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).
10.11 *	First Amendment to Credit Agreement, dated May 9, 2007, among DCP Midstream Operating, LP, DCP Midstream Partners, LP and Wachovia Bank, National Association (attached as Exhibit 99.4 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).
10.12 *	Contribution and Sale Agreement, dated May 21, 2007, between Gas Supply Resources Holdings, Inc., DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on May 25, 2007).
10.13 *	Common Unit Purchase Agreement, dated May 21, 2007, by and among DCP Midstream Partners, LP and the Purchasers listed therein (attached as Exhibit 10.2 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on May 25, 2007).
10.14 *	Contribution Agreement, dated May 23, 2007, among DCP LP Holdings, LP, DCP Midstream, LLC, DCP Midstream GP, LP and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on May 25, 2007).
10.15 *	Common Unit Purchase Agreement, dated June 19, 2007, by and among DCP Midstream Partners, LP and the Purchasers listed therein (attached as Exhibit 10.1 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on June 25, 2007).
10.16 *	Registration Rights Agreement, dated June 22, 2007, by and among DCP Midstream Partners, LP and the Purchasers listed therein (attached as Exhibit 10.2 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on June 25, 2007).
10.17 *	Amended and Restated Credit Agreement, dated June 21, 2007, among DCP Midstream Operating, LP, DCP Midstream Partners, LP and Wachovia Bank, National Association as Administrative Agent (attached as Exhibit 10.1 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on June 27, 2007).
10.18 *	Fourth Amendment to Omnibus Agreement, dated July 1, 2007, by and among DCP Midstream, LLC f/k/a/ Duke Energy Field Services, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP, and DCP Midstream Operating, LP (attached as Exhibit 10.2 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on July 2, 2007).
10.19 *	Amended and Restated Limited Liability Company Agreement of DCP East Texas Holdings, LLC, dated July 1, 2007, between DCP Midstream, LLC and DCP Assets Holding, LP (attached as Exhibit 10.3 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on July 2, 2007).
10.20 *	Fifth Amendment to Omnibus Agreement dated August 7, 2007, among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP, and DCP Midstream Operating, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP s Form 10-Q (File No. 001-32678) filed with the SEC on August 9, 2007).
10.21 *	Sixth Amendment to Omnibus Agreement, dated August 29, 2007, among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LLC, and DCP Midstream Operating, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on September 5, 2007).
10.22 *	Registration Rights Agreement, dated August 29, 2007, by and among DCP Midstream Partners, LP and the Purchasers listed therein (attached as Exhibit 10.2 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on September 5, 2007).
10.23 *	Agreement of Purchase and Sale dated October 1, 2008, by and among Ganesh Energy, LLC, Gas Processing & Pipeline, LLC and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on October 7, 2008).
10.24 *	Seventh Amendment to Omnibus Agreement, dated October 1, 2008, among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LLC and DCP Midstream Operating , LP (attached as Exhibit 10.2 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on October 7, 2008).

10.25 *	Contribution Agreement dated February 24, 2009, among DCP LP Holdings, LLC, DCP Midstream GP, LP DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 10.16 to DCP Midstream Partners, LP s Form 10-K (File No. 001-32678) filed with the SEC on March 5, 2009).
10.26 *	Second Amended and Restated Limited Liability Company Agreement of DCP East Texas Holdings, LLC, dated April 1, 2009 between DCP Midstream, LLC and DCP Assets Holding, LP (attached as Exhibit 10.2 to DCP Midstream Partners, LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on April 7, 2009).

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31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Condensed Consolidated Balance Sheet of DCP Midstream GP, LP as of June 30, 2009.
99.2	Condensed Consolidated Balance Sheet of DCP Midstream, LLC as of June 30, 2009.

* Such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Denver, State of Colorado, on August 10, 2009.

DCP Midstream Partners, LP

By: DCP Midstream GP, LP
its General Partner

By: DCP Midstream GP, LLC
its General Partner

By: /s/ Mark A. Borer
Name: Mark A. Borer
Title: Chief Executive Officer

By: /s/ Angela A. Minas
Name: Angela A. Minas
Title: Vice President and Chief Financial Officer
(Principal Financial Officer)

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EXHIBIT INDEX

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10.16 * Registration Rights Agreement, dated June 22, 2007, by and among DCP Midstream Partners, LP and the Purchasers listed therein (attached as Exhibit 10.2 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on June 25, 2007).

10.17 * Amended and Restated Credit Agreement, dated June 21, 2007, among DCP Midstream Operating, LP, DCP Midstream Partners, LP and Wachovia Bank, National Association as Administrative Agent (attached as Exhibit 10.1 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on June 27, 2007).

10.18 * Fourth Amendment to Omnibus Agreement, dated July 1, 2007, by and among DCP Midstream, LLC f/k/a/ Duke Energy Field Services, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP, and DCP Midstream Operating, LP (attached as Exhibit 10.2 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on July 2, 2007).

10.19 * Amended and Restated Limited Liability Company Agreement of DCP East Texas Holdings, LLC, dated July 1, 2007, between DCP Midstream, LLC and DCP Assets Holding, LP (attached as Exhibit 10.3 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on July 2, 2007).

10.20 * Fifth Amendment to Omnibus Agreement dated August 7, 2007, among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP, and DCP Midstream Operating, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP s Form 10-Q (File No. 001-32678) filed with the SEC on August 9, 2007).

10.21 * Sixth Amendment to Omnibus Agreement, dated August 29, 2007, among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LLC, and DCP Midstream Operating, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on September 5, 2007).

10.22 * Registration Rights Agreement, dated August 29, 2007, by and among DCP Midstream Partners, LP and the Purchasers listed therein (attached as Exhibit 10.2 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on September 5, 2007).

10.23 * Agreement of Purchase and Sale dated October 1, 2008, by and among Ganesh Energy, LLC, Gas Processing & Pipeline, LLC and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on October 7, 2008).

10.24 * Seventh Amendment to Omnibus Agreement, dated October 1, 2008, among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LLC and DCP Midstream Operating , LP (attached as Exhibit 10.2 to DCP Midstream Partners LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on October 7, 2008).

10.25 * Contribution Agreement dated February 24, 2009, among DCP LP Holdings, LLC, DCP Midstream GP, LP DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 10.16 to DCP Midstream Partners, LP s Form 10-K (File No. 001-32678) filed with the SEC on March 5, 2009).

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10.26 *	Second Amended and Restated Limited Liability Company Agreement of DCP East Texas Holdings, LLC, dated April 1, 2009 between DCP Midstream, LLC and DCP Assets Holding, LP (attached as Exhibit 10.2 to DCP Midstream Partners, LP s current report on Form 8-K (File No. 001-32678) filed with the SEC on April 7, 2009).
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Condensed Consolidated Balance Sheet of DCP Midstream GP, LP as of June 30, 2009.
99.2	Condensed Consolidated Balance Sheet of DCP Midstream, LLC as of June 30, 2009.

* Such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.