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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2011

or

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

For the transition period from to

Commission File Number: 001-32678

DCP MIDSTREAM PARTNERS, LP
(Exact name of registrant as specified in its charter)

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐

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

As of November 3, 2011, there were outstanding 44,432,449 common units representing limited partner interests.

DCP MIDSTREAM PARTNERS, LP
FORM 10-Q FOR THE QUARTER ENDED SEPTEMBER 30, 2011

TABLE OF CONTENTS

Item		Page
	PART I. FINANCIAL INFORMATION	
1.	Financial Statements (unaudited):	
	Condensed Consolidated Balance Sheets as of September 30, 2011 and December 31, 2010	1
	Condensed Consolidated Statements of Operations for the Three and Nine Months Ended September 30, 2011 and 2010	2
	Condensed Consolidated Statements of Comprehensive Income for the Three and Nine Months Ended September 30, 2011 and 2010	3
	Condensed Consolidated Statements of Cash Flows for the Nine Months Ended September 30, 2011 and 2010	4
	Condensed Consolidated Statements of Changes in Equity for the Nine Months Ended September 30, 2011 and 2010	5
	Notes to the Condensed Consolidated Financial Statements	6
2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	51
3.	Quantitative and Qualitative Disclosures about Market Risk	74
4.	Controls and Procedures	79
	PART II. OTHER INFORMATION	
1.	Legal Proceedings	79
1A.	Risk Factors	79
6.	Exhibits	80
	Signatures	81
	Exhibit Index	82
	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002	

GLOSSARY OF TERMS

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

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

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in "Item 1A. Risk Factors" in this Quarterly Report on Form 10-Q and in our Annual Report on Form 10-K for the year ended December 31, 2010, as well as the following risks and uncertainties:

- the extent of changes in commodity prices, our ability to effectively limit a portion of the adverse impact of potential changes in prices through derivative financial instruments, and the potential impact of price and producers' access to capital on natural gas drilling, demand for our services, and the volume of NGLs and condensate extracted;
- general economic, market and business conditions;
- the level and success of natural gas drilling around our assets, the level and quality of gas production volumes around our assets and our ability to connect supplies to our gathering and processing systems in light of competition;
- our ability to grow through acquisitions, contributions from affiliates, or organic growth projects, and the successful integration and future performance of such assets;
- our ability to access the debt and equity markets and the resulting cost of capital, which will depend on general market conditions, our financial and operating results, inflation rates, interest rates and our ability to effectively limit a portion of the adverse effects of potential changes in interest rates by entering into derivative financial instruments, our ability to comply with the covenants to our credit agreement and our debt securities, as well as our ability to maintain our credit ratings;
- our ability to purchase propane from our principal suppliers and make associated profitable sales transactions for our wholesale propane logistics business;
- our ability to construct facilities in a timely fashion, which is partially dependent on obtaining required construction, environmental and other permits issued by federal, state and municipal governments, or agencies thereof, the availability of specialized contractors and laborers, and the price of and demand for materials;
- the creditworthiness of counterparties to our transactions;
- weather and other natural phenomena, including their potential impact on demand for the commodities we sell and the operation of company-owned and third party-owned infrastructure;
- new, additions to and changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment, including climate change legislation, or the increased regulation of our industry;
- our ability to obtain insurance on commercially reasonable terms, if at all, as well as the adequacy of insurance to cover our losses;
- industry changes, including the impact of consolidations, increased delivery of liquefied natural gas to the United States, alternative energy sources, technological advances and changes in competition; and
- the amount of collateral we may be required to post from time to time in our transactions including changes resulting from the Dodd-Frank Wall Street Reform and Consumer Protection Act.

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

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

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

	September 30, 2011	December 31, 2010
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2.0	$ 6.7
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.3 and $0.5 million, respectively	70.3	89.3
Affiliates	57.1	61.7
Inventories	57.4	64.1
Unrealized gains on derivative instruments	5.6	1.9
Assets held for sale	3.1	6.2
Other	2.7	2.1
Total current assets	198.2	232.0
Property, plant and equipment, net	1,137.7	1,097.1
Goodwill	146.9	139.3
Intangible assets, net	115.4	119.3
Investments in unconsolidated affiliates	222.2	216.9
Unrealized gains on derivative instruments	11.9	1.4
Other long-term assets	7.1	7.2
Total assets	$ 1,839.4	$ 1,813.2
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 75.7	$ 99.1
Affiliates	45.2	37.6
Unrealized losses on derivative instruments	33.6	43.0
Revolving credit facility	476.0	—
Other	61.5	31.5
Total current liabilities	692.0	211.2
Long-term debt	249.8	647.8
Unrealized losses on derivative instruments	21.3	50.3
Other long-term liabilities	16.0	53.1
Total liabilities	979.1	962.4
Commitments and contingent liabilities		
Equity:		
Predecessor equity	—	112.6
Common unitholders (44,432,449 and 40,478,383 units issued and outstanding, respectively)	672.8	552.2
General partner	(4.9)	(6.4)
Accumulated other comprehensive loss	(22.8)	(27.7)
Total partners' equity	645.1	630.7
Noncontrolling interests	215.2	220.1
Total equity	860.3	850.8
Total liabilities and equity	$ 1,839.4	$ 1,813.2

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(Millions, except per unit amounts)			
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 150.4	$ 102.8	$ 603.2	$431.4
Sales of natural gas, propane, NGLs and condensate to affiliates	140.0	124.9	440.0	394.7
Transportation, processing and other	31.1	23.1	92.0	66.8
Transportation, processing and other to affiliates	9.7	5.6	22.9	16.2
Gains (losses) from commodity derivative activity, net	51.8	(15.8)	26.1	13.0
Gains (losses) from commodity derivative activity, net — affiliates	0.3	(0.7)	(1.6)	(1.0)
Total operating revenues	383.3	239.9	1,182.6	921.1
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	180.3	155.2	592.8	524.8
Purchases of natural gas, propane and NGLs from affiliates	77.0	45.0	313.8	213.9
Operating and maintenance expense	31.5	19.2	77.3	58.8
Depreciation and amortization expense	20.6	19.2	60.6	55.7
General and administrative expense	4.6	3.3	12.5	10.4
General and administrative expense — affiliates	4.8	4.9	14.5	14.6
Step acquisition — equity interest re-measurement gain	—	(9.1)	—	(9.1)
Other income	(0.2)	(0.5)	(0.4)	(1.0)
Other income — affiliates	—	—	—	(3.0)
Total operating costs and expenses	318.6	237.2	1,071.1	865.1
Operating income	64.7	2.7	111.5	56.0
Interest expense	(8.6)	(7.5)	(25.0)	(22.0)
Earnings from unconsolidated affiliates	10.0	8.2	28.6	29.0
Income before income taxes	66.1	3.4	115.1	63.0
Income tax expense	(0.2)	(0.1)	(0.4)	(0.5)
Net income	65.9	3.3	114.7	62.5
Net loss (income) attributable to noncontrolling interests	0.4	(3.3)	(12.8)	(4.4)
Net income attributable to partners	66.3	—	101.9	58.1
Net income attributable to predecessor operations	—	(4.1)	—	(10.4)
General partner's interest in net income	(6.8)	(4.1)	(18.5)	(12.1)
Net income (loss) allocable to limited partners	$ 59.5	$ (8.2)	$ 83.4	$ 35.6
Net income (loss) per limited partner unit — basic	$ 1.35	$ (0.23)	$ 1.93	$ 1.01
Net income (loss) per limited partner unit — diluted	$ 1.35	$ (0.23)	$ 1.93	$ 1.01
Weighted-average limited partner units outstanding — basic	44.1	36.0	43.2	35.1
Weighted-average limited partner units outstanding — diluted	44.2	36.0	43.2	35.1

See accompanying notes to condensed consolidated financial statements.

Table of Contents

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(Millions)			
Net income	$65.9	$ 3.3	$114.7	$ 62.5
Other comprehensive income (loss):				
Reclassification of cash flow hedge losses into earnings	5.2	5.3	15.6	16.9
Net unrealized losses on cash flow hedges	(5.5)	(4.8)	(9.8)	(18.2)
Total other comprehensive (loss) income	(0.3)	0.5	5.8	(1.3)
Total comprehensive income	65.6	3.8	120.5	61.2
Total comprehensive loss (income) attributable to noncontrolling interests	0.4	(3.3)	(12.8)	(4.4)
Total comprehensive income attributable to partners	$66.0	$ 0.5	$107.7	$ 56.8

See accompanying notes to condensed consolidated financial statements.

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

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(Millions)	
OPERATING ACTIVITIES:		
Net income	$ 114.7	$ 62.5
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	60.6	55.7
Earnings from unconsolidated affiliates	(28.6)	(29.0)
Distributions from unconsolidated affiliates	36.3	30.4
Step acquisition — equity interest re-measurement gain	—	(9.1)
Other, net	3.5	(0.2)
Change in operating assets and liabilities, which provided (used) cash net of effects of acquisitions:		
Accounts receivable	23.9	52.1
Inventories	6.7	19.0
Net unrealized gains on derivative instruments	(46.4)	(11.6)
Accounts payable	(16.5)	(44.6)
Accrued interest	2.2	—
Other current assets and liabilities	(4.8)	10.7
Other long-term assets and liabilities	(2.7)	1.0
Net cash provided by operating activities	148.9	136.9
INVESTING ACTIVITIES:		
Capital expenditures	(46.4)	(37.1)
Acquisitions, net of cash acquired	(60.5)	(103.8)
Acquisition of unconsolidated affiliate	(114.3)	—
Investments in unconsolidated affiliates	(13.2)	(27.0)
Return of investment from unconsolidated affiliates	1.6	1.2
Proceeds from sale of assets	0.2	1.7
Proceeds from sales of available-for-sale securities	—	10.1
Net cash used in investing activities	(232.6)	(154.9)
FINANCING ACTIVITIES:		
Proceeds from debt	832.0	658.2
Payments of debt	(754.0)	(658.4)
Payment of deferred financing costs	(0.1)	(1.6)
Proceeds from issuance of common units, net of offering costs	152.0	93.2
Excess purchase price over acquired assets	(35.7)	—
Net change in advances to predecessor from DCP Midstream, LLC	—	19.8
Distributions to unitholders and general partner	(97.5)	(74.4)
Distributions to noncontrolling interests	(26.8)	(16.0)
Contributions from noncontrolling interests	9.1	10.4
Purchase of additional interest in a subsidiary	—	(3.5)
Net cash provided by financing activities	79.0	27.7
Net change in cash and cash equivalents	(4.7)	9.7
Cash and cash equivalents, beginning of period	6.7	2.1
Cash and cash equivalents, end of period	$ 2.0	$ 11.8

See accompanying notes to condensed consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Unaudited)

	Partner's Equity					
	Predecessor Equity	Common Unitholders	General Partner	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Equity
	(Millions)					
Balance, January 1, 2011	$ 112.6	$ 552.2	$ (6.4)	$ (27.7)	$ 220.1	$ 850.8
Net change in parent advances	1.7	—	—	—	—	1.7
Acquisition of Southeast Texas	(114.3)	—	—	—	—	(114.3)
Excess purchase price over acquired assets	—	(34.8)	—	(0.9)	—	(35.7)
Issuance of 3,941,667 common units	—	152.2	—	—	—	152.2
Equity-based compensation	—	2.9	—	—	—	2.9
Distributions to DCP Midstream, LLC	—	(2.6)	—	—	—	(2.6)
Distributions to unitholders and general partner	—	(80.5)	(17.0)	—	—	(97.5)
Distributions to noncontrolling interests	—	—	—	—	(26.8)	(26.8)
Contributions from noncontrolling interests	—	—	—	—	9.1	9.1
Comprehensive income:						
Net income	—	83.4	18.5	—	12.8	114.7
Reclassification of cash flow hedges into earnings	—	—	—	15.6	—	15.6
Net unrealized losses on cash flow hedges	—	—	—	(9.8)	—	(9.8)
Total comprehensive income	—	83.4	18.5	5.8	12.8	120.5
Balance, September 30, 2011	$ —	$ 672.8	$ (4.9)	$ (22.8)	$ 215.2	$ 860.3

	Partner's Equity					
	Predecessor Equity	Common Unitholders	General Partner	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total Equity
	(Millions)					
Balance, January 1, 2010	$ 70.8	$ 415.5	$ (5.9)	$ (31.9)	$ 227.7	$676.2
Net change in parent advances	19.8	—	—	—	—	19.8
Purchase of additional interest in a subsidiary	—	1.0	—	—	(5.5)	(4.5)
Excess purchase price over acquired assets	—	(0.8)	—	—	—	(0.8)
Issuance of 2,990,000 common units	—	93.1	—	—	—	93.1
Equity-based compensation	—	0.2	—	—	—	0.2
Distributions to unitholders and general partner	—	(62.6)	(11.8)			(74.4)
Distributions to noncontrolling interests	—	—	—	—	(16.0)	(16.0)
Contributions from noncontrolling interests	—	—	—	—	10.4	10.4
Comprehensive income (loss):						
Net income attributable to predecessor operations	10.4	—	—	—	—	10.4
Net income	—	36.1	11.6	—	4.4	52.1
Reclassification of cash flow hedge losses into earnings	—	—	—	16.9	—	16.9
Net unrealized losses on cash flow hedges	—	—	—	(18.2)	—	(18.2)
Total comprehensive income (loss)	10.4	36.1	11.6	(1.3)	4.4	61.2
Balance, September 30, 2010	$ 101.0	$ 482.5	$ (6.1)	$ (33.2)	$ 221.0	$765.2

See accompanying notes to condensed consolidated financial statements.

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

1. Description of Business and Basis of Presentation

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

We are a Delaware limited partnership that was formed in August 2005. We completed our initial public offering on December 7, 2005. Our partnership includes: our Northern Louisiana system; our Southern Oklahoma system; our 40% limited liability company interest in Discovery Producer Services LLC, or Discovery; our Wyoming system; a 75% interest in Collbran Valley Gas Gathering, LLC, or Collbran or our Colorado system (of which 5% was acquired in February 2010); our 50.1% interest in our DCP East Texas Holdings, LLC, or our East Texas system; our Michigan system; our 33.33% interest in our DCP Southeast Texas Holdings, GP, or our Southeast Texas system acquired in January 2011; our wholesale propane logistics business (which includes Atlantic Energy acquired in July 2010); and our NGL logistics business (which includes Marysville Hydrocarbons Holdings, LLC, or Marysville, acquired in December 2010, the Wattenberg pipeline acquired in January 2010 and our 100% interest in the Black Lake Pipeline Company, or Black Lake, 55% of which was acquired in July 2010, comprised of: (1) a 5% interest acquired from DCP Midstream, LLC, in a transaction among entities under common control, and (2) an additional 50% interest acquired from an affiliate of BP PLC; and the DJ Basin NGL Fractionators acquired in March 2011).

Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as the General Partner, and is wholly-owned by DCP Midstream, LLC. DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC, is owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by ConocoPhillips. DCP Midstream, LLC directs our business operations through its ownership and control of the General Partner. DCP Midstream, LLC and its affiliates' employees provide administrative support to us and operate most of our assets. DCP Midstream, LLC owns approximately 27% of us.

The condensed consolidated financial statements include the accounts of the Partnership and all majority-owned subsidiaries where we have the ability to exercise control and undivided interests in jointly owned assets. Investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence, are accounted for using the equity method.

On January 1, 2011, we acquired a 33.33% interest in Southeast Texas for $150.0 million, in a transaction among entities under common control. This transfer of net assets between entities under common control was accounted for as if the transfer occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our condensed consolidated financial statements have been adjusted to include the historical results of our equity interest in Southeast Texas for all periods presented. We refer to our 33.33% interest in Southeast Texas, prior to our acquisition from DCP Midstream, LLC in January 2011, as our "predecessor." We recognize transfers of net assets between entities under common control at DCP Midstream, LLC's basis in the net assets contributed. The amount of the purchase price in excess of DCP Midstream, LLC's basis in the net assets is recognized as a reduction to partners' equity. The financial statements of our predecessor have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessor had been operated as an unaffiliated entity.

The results of operations for acquisitions accounted for as business combinations have been included in the condensed consolidated financial statements since their respective acquisition dates and we have retrospectively adjusted the December 31, 2010 condensed consolidated balance sheet for changes in our preliminary purchase price allocation for our December 30, 2010 acquisition of Marysville.

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

The condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. Conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the condensed consolidated financial statements and notes. Although these estimates are based on management's best available knowledge of current and expected future events, actual results could differ from those estimates. All intercompany balances and transactions have been eliminated. Transactions between us and other DCP Midstream, LLC operations have been identified in the condensed consolidated financial statements as transactions between affiliates.

The accompanying unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission, or SEC. Accordingly, these condensed consolidated financial statements reflect all adjustments, consisting only of normal recurring adjustments, that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective interim periods. Certain information and notes normally included in our annual financial statements have been condensed or omitted from these interim financial statements pursuant to such rules and regulations. Results of operations for the three and nine months ended September 30, 2011 are not necessarily indicative of the results that may be expected for the year ending December 31, 2011. These condensed consolidated financial statements and other information included in this Quarterly Report on Form 10-Q should be read in conjunction with the consolidated financial statements and notes thereto included in our Current Report on Form 8-K filed on June 17, 2011.

2. Recent Accounting Pronouncements

***Financial Accounting Standards Board, or FASB, Accounting Standards Update, or ASU, 2011-08 "Intangibles – Goodwill and Other (Topic 350),"* or ASU 2011-08** — In September 2011, the FASB issued ASU 2011-08, which amends Accounting Standards Codification, or ASC, Topic 350 "Intangibles — Goodwill and Other." ASU 2011-08 provides additional guidance on the two-step test for goodwill impairment as previously described in Topic 350 "Intangibles — Goodwill and Other." Under the new guidance, entities may elect to first assess qualitative factors instead of calculating the fair value of a reporting unit unless the entity determines that it is more likely than not the fair value of the reporting unit is less than its carrying value. This ASU is effective for interim and annual goodwill impairment tests performed for fiscal years beginning after December 15, 2011, with early adoption permitted. We elected to adopt ASU 2011-08 for our 2011 annual goodwill impairment test. There was no impact from the adoption of ASU 2011-08 on our condensed consolidated results of operations, cash flows and financial position.

***ASU, 2011-04 "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs",* or ASU 2011-04** — In May 2011, the FASB issued ASU 2011-04 which amends ASC, Topic 820 "Fair Value Measurements and Disclosures" to change the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements, clarify the FASB's intent about the application of existing fair value measurement requirements, and change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The provisions of ASU 2011-04 are effective for us for interim and annual periods beginning after December 15, 2011 and we are currently assessing the impact of adoption on our consolidated results of operations, cash flows and financial position.

3. Acquisitions

On August 1, 2011, we reached an agreement with DCP Midstream, LLC for us to construct a 200 MMcf/d cryogenic natural gas processing plant, or the Eagle Plant, in the Eagle Ford shale which represents an investment of approximately $120.0 million. In support of our construction of the Eagle Plant, we entered into a 15 year fee-based processing agreement with an affiliate of DCP Midstream, LLC, which provides us with a fixed demand charge for 150 MMcf/d along with a throughput fee on all volumes processed. The processing agreement commences with commercial operations of the new plant, which is expected to be online by the fourth quarter of 2012. In conjunction with the agreement, we also entered into a purchase and sale agreement with DCP Midstream, LLC to purchase certain tangible assets and land located in the Eagle Ford Shale for $23.4 million, financed initially at closing with borrowings under the Partnership's revolving credit facility.

On March 24, 2011, we acquired two NGL fractionation facilities in Weld County, Colorado, located in the Denver-Julesburg, or DJ, Basin, from a third party in a transaction accounted for as an asset acquisition. We paid a purchase price of $30.0 million, financed initially at closing with borrowings under the Partnership's revolving credit facility, and received a post-closing purchase price adjustment of $0.4 million. The NGL fractionation facilities, or the DJ Basin NGL Fractionators, are located on DCP Midstream, LLC's processing plant sites and are operated by DCP Midstream, LLC. Subsequent to our acquisition, DCP Midstream, LLC will continue to operate and supply certain committed NGLs produced by them in Weld County to our DJ Basin NGL Fractionators under the existing agreements that are effective through March 2018. The results of the assets are included in our NGL Logistics segment prospectively, from the date of acquisition.

On January 1, 2011, we acquired a 33.33% interest in Southeast Texas for $150.0 million, in a transaction among entities under common control, financed initially at closing with proceeds from our November 2010 public equity offering and borrowings under the Partnership's revolving credit facility. DCP Midstream, LLC's historical carrying value of the net assets acquired in the acquisition was $114.3 million; accordingly we have recorded the $35.7 million excess purchase price over acquired assets as a decrease in common unitholders equity. The results of our 33.33% interest in Southeast Texas are included in our Natural Gas Services segment for all periods presented.

On December 30, 2010, we acquired all of the interests in Marysville. The acquisition involved three separate transactions with a number of parties. We acquired a 90% interest in Marysville from Dart Energy Corporation, a 5% interest in Marysville from Prospect Street Energy, LLC and 100% of EE Group, LLC, which owned the remaining 5% interest in Marysville. We paid a purchase price of $94.8 million plus $6.0 million for net working capital and other adjustments for an aggregate purchase price of $100.8 million, subject to customary purchase price adjustments, for our 100% interest. The cash purchase was financed initially at closing with borrowings under the Partnership's revolving credit facility. $21.2 million of the purchase price has been deposited in an indemnity escrow to satisfy certain tax liabilities and provide for breaches of representations and warranties of the sellers. $19.5 million remains in the escrow account after $1.7 million was released on June 15, 2011. The results of the Marysville acquisition are included in our NGL Logistics segment prospectively, from the date of acquisition.

On January 4, 2011, we merged two wholly-owned subsidiaries of Marysville and converted the combined entity's organizational structure from a corporation to a limited liability company. This conversion to a limited liability company triggered tax liabilities, resulting from built-in tax gains recognized in the transaction, to become currently payable. Accordingly, $35.0 million of estimated deferred tax liabilities associated with this transaction and recorded at December 31, 2010, became currently payable as of January 4, 2011. These tax liabilities are unrelated to the tax liabilities of Marysville for which an indemnity escrow has been established. These tax liabilities may be greater or less than the $35.0 million we initially recorded in our balance sheet, depending on the final accounting for the Marysville business combination. On April 18, 2011, we made an estimated federal tax payment of $29.3 million related to our $35.0 million tax liability that resulted from our acquisition of Marysville. The remaining $5.7 million estimated tax payable is included in other current liabilities in our condensed consolidated balance sheet as of September 30, 2011.

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

We have updated our accounting for the Marysville business combination for the fair value of assets acquired and liabilities assumed including intangible assets and property, plant and equipment and goodwill. The purchase price allocation is preliminary and is based on initial estimates of fair values at the date of the acquisition. We are currently evaluating the preliminary purchase price allocation, which will be adjusted as additional information relative to the fair value of assets and liabilities becomes available. This allocation may change in subsequent financial statements pending the final estimates of fair value and the final outcome of our estimated tax liabilities. The preliminary purchase price allocation as of September 30, 2011 is as follows:

	September 30, 2011 (Millions)
Aggregate consideration	$ 100.8
Cash	3.1
Accounts receivable	0.7
Inventory	4.6
Other current assets	0.7
Property, plant and equipment	57.1
Intangible assets	33.0
Goodwill	39.7
Other long-term assets	1.2
Other current liabilities	(4.3)
Long-term liabilities	(35.0)
Total preliminary purchase price allocation	$ 100.8

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

Combined Financial Information

The results of our 33.33% interest in Southeast Texas are included in the condensed consolidated statements of operations for the three and nine months ended September 30, 2011 and 2010. The following table presents the previously reported condensed consolidated statements of operations for the three and nine months ended September 30, 2010, adjusted for the acquisition of a 33.33% interest in Southeast Texas from DCP Midstream, LLC:

Three Months Ended September 30, 2010

	DCP Midstream Partners, LP (As previously reported)	Southeast Texas (a)	Combined DCP Midstream Partners, LP (As currently reported)
		(Millions)	
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 227.7	$ —	$ 227.7
Transportation, processing and other	28.7	—	28.7
Losses from commodity derivative activity, net	(16.5)	—	(16.5)
Total operating revenues	239.9	—	239.9
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	200.2	—	200.2
Operating and maintenance expense	19.2	—	19.2
Depreciation and amortization expense	19.2	—	19.2
General and administrative expense and other	8.2	—	8.2
Step acquisition — equity interest re-measurement gain	(9.1)	—	(9.1)
Other income	(0.5)	—	(0.5)
Total operating costs and expenses	237.2	—	237.2
Operating income	2.7	—	2.7
Interest expense, net	(7.5)	—	(7.5)
Earnings from unconsolidated affiliates	4.1	4.1	8.2
Income before income taxes	(0.7)	4.1	3.4
Income tax expense	(0.1)	—	(0.1)
Net (loss) income	(0.8)	4.1	3.3
Net income attributable to noncontrolling interests	(3.3)	—	(3.3)
Net (loss) income attributable to partners	$ (4.1)	$ 4.1	$ —

(a) The financial statements of our predecessor have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessor had been operated as an unaffiliated entity. Specifically, the terms of the joint venture agreement provide that distributions and earnings to us for the first seven years related to storage and transportation gross margin will be pursuant to a fee-based arrangement, based on storage capacity and tailgate volumes. Distributions and earnings related to the gathering and processing business, along with reductions for all expenditures, will be pursuant to our and DCP Midstream, LLC's respective ownership interests in Southeast Texas. These terms of the agreement are not reflected in the historical financial statements.

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

Nine Months Ended September 30, 2010

	DCP Midstream Partners, LP (As previously reported)	Southeast Texas (a)(b)	Combined DCP Midstream Partners, LP (As currently reported)
		(Millions)	
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 826.1	$ —	$ 826.1
Transportation, processing and other	83.0	—	83.0
Gains from commodity derivative activity, net	12.0	—	12.0
Total operating revenues	921.1	—	921.1
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	738.7	—	738.7
Operating and maintenance expense	58.8	—	58.8
Depreciation and amortization expense	55.7	—	55.7
General and administrative expense and other	25.0	—	25.0
Step acquisition — equity interest re-measurement gain	(9.1)	—	(9.1)
Other income	(4.0)	—	(4.0)
Total operating costs and expenses	865.1	—	865.1
Operating income	56.0	—	56.0
Interest expense, net	(22.0)	—	(22.0)
Earnings from unconsolidated affiliates	18.6	10.4	29.0
Income before income taxes	52.6	10.4	63.0
Income tax expense	(0.5)	—	(0.5)
Net income	52.1	10.4	62.5
Net income attributable to noncontrolling interests	(4.4)	—	(4.4)
Net income attributable to partners	$ 47.7	$ 10.4	$ 58.1

(a) The results of our 33.33% interest in Southeast Texas for the nine months ended September 30, 2010 includes the impact of Hurricane Ike business interruption insurance recoveries.

(b) The financial statements of our predecessor have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessor had been operated as an unaffiliated entity. Specifically, the terms of the joint venture agreement provide that distributions and earnings to us for the first seven years related to storage and transportation gross margin will be pursuant to a fee-based arrangement, based on storage capacity and tailgate volumes. Distributions and earnings related to the gathering and processing business, along with reductions for all expenditures, will be pursuant to our and DCP Midstream, LLC's respective ownership interests in Southeast Texas. These terms of the agreement are not reflected in the historical financial statements.

The results of operations for acquisitions accounted for as a business combination are included in the DCP Midstream Partners, LP results subsequent to the date of acquisition. Accordingly, for the three and nine months ended September 30, 2011 total operating revenues of $6.0 million and $21.9 million, respectively, and net income attributable to the Partnership of $2.9 million and $10.6 million, respectively, associated with Marysville, are included in the condensed consolidated statement of operations. Pro forma information is presented for comparative periods prior to the date of acquisition, however, comparative periods in the condensed consolidated financial statements are not adjusted to include the results of the acquisition.

The following table presents unaudited pro forma information for the condensed consolidated statement of operations for the three and nine months ended September 30, 2010, as if the acquisition of Marysville had occurred at the beginning of the period presented.

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

	Three Months Ended September 30, 2010			Nine Months Ended September 30, 2010		
	DCP Midstream Partners, LP	Acquisition of Marysville	DCP Midstream Partners, LP Pro Forma	DCP Midstream Partners, LP	Acquisition of Marysville	DCP Midstream Partners, LP Pro Forma
	(Millions, except per unit amounts)					
Total operating revenues	$ 239.9	$ 4.4	$ 244.3	$ 921.1	$ 19.2	$ 940.3
Net income attributable to partners	—	1.4	1.4	58.1	7.7	65.8
Less:						
Net income attributable to predecessor operations	(4.1)	—	(4.1)	(10.4)	—	(10.4)
General partner unitholders interest in net income	(4.1)	—	(4.1)	(12.1)	—	(12.1)
Net (loss) income allocable to limited partners	$ (8.2)	$ 1.4	$ (6.8)	$ 35.6	$ 7.7	$ 43.3
Net (loss) income per limited partner unit — basic and diluted	$ (0.23)	$ 0.04	$ (0.19)	$ 1.01	$ 0.22	$ 1.23

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

4. Agreements and Transactions with Affiliates

DCP Midstream, LLC

Omnibus Agreement and Other General and Administrative Charges

We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. In January 2011, we extended the omnibus agreement through December 31, 2011 for an annual amount of $10.2 million.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(Millions)			
Omnibus Agreement	$ 2.6	$ 2.5	$ 7.6	$ 7.4
Other fees — DCP Midstream, LLC	2.2	2.3	6.7	7.0
Total — DCP Midstream, LLC	$ 4.8	$ 4.8	$14.3	$14.4

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

Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC for certain costs incurred and centralized corporate functions performed by DCP Midstream, LLC on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, taxes and engineering. 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; and
- DCP Midstream, LLC's obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to commercial contracts with respect to its business or operations that were in effect at the closing of our initial public offering until the expiration of such contracts.

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

East Texas incurs general and administrative expenses directly from DCP Midstream, LLC. East Texas incurred $1.9 million and $2.0 million for the three months ended September 30, 2011 and 2010, respectively, and $5.7 million and $5.9 million for the nine months ended September 30, 2011 and 2010, respectively, for general and administrative expenses from DCP Midstream, LLC.

In addition to the Omnibus Agreement and amounts incurred by East Texas, we incurred other general and administrative fees with DCP Midstream, LLC of $0.3 million and $0.3 million for the three months ended September 30, 2011 and 2010, respectively, and $1.0 million and $1.1 million for the nine months ended September 30, 2011 and 2010, respectively. These amounts include allocated expenses, including professional services, insurance and internal audit.

Other Agreements and Transactions with DCP Midstream, LLC

DCP Midstream, LLC was a significant customer during the three and nine months ended September 30, 2011 and 2010.

We sell a portion of our residue gas, NGLs and condensate to, purchase natural gas and other petroleum products from, and provide gathering and transportation services for, DCP Midstream, LLC. We anticipate continuing to purchase from and sell commodities and services to DCP Midstream, LLC in the ordinary course of business. In addition, DCP Midstream, LLC conducts derivative activities on our behalf. We have and may continue to enter into market based derivative transactions directly with DCP Midstream, LLC, whereby DCP Midstream is the counterparty.

We have a contractual arrangement with DCP Midstream, LLC, through March 2022, in which we pay DCP Midstream, LLC a fee for processing services associated with the gas we gather on our Southern Oklahoma system, which is part of our Natural Gas Services segment. In addition, in February 2010, a contract was signed with DCP Midstream, LLC providing for adjustments to those fees based upon plant efficiencies related to our portion of volumes from the Southern Oklahoma system being processed at DCP Midstream, LLC's plant through March 2022. We generally report fees associated with these activities in the condensed consolidated statements of operations as purchases of natural gas, propane, NGLs and condensate from affiliates. In addition, as part of this arrangement, DCP Midstream, LLC pays us a fee for certain gathering services. We generally report revenues associated with these activities in the condensed consolidated statements of operations as transportation, processing and other to affiliates.

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

On August 1, 2011, we reached an agreement with DCP Midstream, LLC for us to construct a 200 MMcf/d cryogenic natural gas processing plant, or the Eagle Plant, in the Eagle Ford shale which represents an investment of approximately $120.0 million. In support of our construction of the Eagle Plant, we entered into a 15 year fee-based processing agreement with an affiliate of DCP Midstream, LLC, which provides us with a fixed demand charge for 150 MMcf/d along with a throughput fee on all volumes processed. The processing agreement commences with commercial operations of the new plant, which is expected to be online by the fourth quarter of 2012. In conjunction with the agreement, we also entered into a purchase and sale agreement with DCP Midstream, LLC to purchase certain tangible assets and land located in the Eagle Ford Shale for $23.4 million.

During the three months ended September 30, 2011, East Texas received cash and recognized $0.8 million in business interruption recoveries, and received $7.0 million in cash for the business interruption recoveries that were recognized in the second quarter of 2011 related to the first quarter 2009 fire that was caused by a third party underground pipeline rupture outside of our property, or collectively the East Texas recovery settlement. We have allocated the $0.8 million recoveries based upon relative ownership percentages at the time the losses were incurred and for the three months ended September 30, 2011, recorded $0.8 million to our condensed consolidated statement of operations in “sales of natural gas, propane, NGLs and condensate”, with $0.4 million representing DCP Midstream, LLC’s portion in “net income attributable to noncontrolling interests”.

In conjunction with our acquisition of a 33.33% interest in Southeast Texas from DCP Midstream, LLC for $150.0 million in our Natural Gas Services segment, we entered into a joint venture agreement. The terms of the joint venture agreement provide that distributions and earnings to us for the first seven years related to storage and transportation gross margin will be pursuant to a fee-based arrangement, based on storage capacity and tailgate volumes. Distributions and earnings related to the gathering and processing business, along with reductions for all expenditures, will be pursuant to our and DCP Midstream, LLC’s respective ownership interests in Southeast Texas. This transaction closed on January 1, 2011.

In conjunction with our acquisition of a 50.1% limited liability company interest in East Texas, which is part of our Natural Gas Services segment, we entered into agreements with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse East Texas for certain expenditures on East Texas capital projects. These reimbursements are for certain capital projects which have commenced within three years from the respective acquisition dates. DCP Midstream, LLC made capital contributions to East Texas for capital projects of $3.5 million and $1.3 million for the three months ended September 30, 2011 and 2010, respectively, and $9.1 million and $10.4 million for the nine months ended September 30, 2011 and 2010, respectively.

On September 16, 2010, we entered into an agreement with DCP Midstream, LLC to sell certain surplus equipment at Collbran, part of our Natural Gas Services segment, with a net book value of $6.2 million for net proceeds of $3.6 million. The surplus equipment is the result of a consolidation of operations at our Anderson Gulch plant in the Piceance Basin. The net proceeds of $3.6 million were distributed 75% to us and 25% to the noncontrolling interest in Collbran, based upon proportionate ownership, during the year ended December 31, 2010. The sale was completed when title to the surplus equipment passed to DCP Midstream, LLC in March 2011. We have recognized a distribution of $2.6 million for nine months ended September 30, 2011 to DCP Midstream, LLC in our condensed consolidated statements of changes in equity representing the difference between the net book value and the proceeds received for the surplus equipment.

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

In our NGL Logistics segment, we also have a contractual arrangement with a subsidiary of DCP Midstream, LLC that provides that DCP Midstream, LLC will pay us to transport NGLs over our Seabreeze and Wilbreeze pipelines, pursuant to fee-based rates that will be applied to the volumes transported. DCP Midstream, LLC is the sole shipper on these pipelines under the transportation agreements. We generally report revenues associated with these activities in the condensed consolidated statements of operations as transportation, processing and other to affiliates.

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

In conjunction with our acquisition of the Wattenberg pipeline, which is part of our NGL Logistics segment, we signed a transportation agreement with DCP Midstream, LLC pursuant to fee-based rates that will be applied to the volumes transported, which was effective through December 31, 2010. Effective January 1, 2011, we entered into a 10-year dedication and transportation agreement with a subsidiary of DCP Midstream, LLC whereby certain NGL volumes produced at several of DCP Midstream, LLC's processing facilities are dedicated for transportation on the Wattenberg pipeline. We collect fee-based transportation revenues under our tariff. We generally report revenues associated with these activities in the condensed consolidated statements of operations as transportation, processing and other to affiliates.

In conjunction with our acquisition of our DJ Basin NGL Fractionators in our NGL Logistics segment, we pay a fee to DCP Midstream, LLC to operate our DJ Basin NGL Fractionators and receive fees for the processing of DCP Midstream, LLC's committed NGLs produced by them in Weld County at our DJ Basin NGL Fractionators under agreements that are effective through March 2018.

DCP Midstream, LLC has issued parental guarantees, totaling $70.0 million as of September 30, 2011, in favor of certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with those counterparties. We pay DCP Midstream, LLC interest of 0.5% per annum on these outstanding guarantees.

DCP Midstream, LLC has issued parental guarantees for its 49.9% limited liability company interest in East Texas, totaling $6.0 million as of September 30, 2011, in favor of certain counterparties to processing and transportation agreements at East Texas. Concurrently, we issued similar guarantees for our 50.1% interest.

Spectra Energy

We have propane supply agreements with Spectra Energy, effective through April 2012, which provide us propane supply at our marine terminals, which are included in our Wholesale Propane Logistics segment, for up to approximately 185 million gallons of propane annually. Additionally, we have transportation agreements with Spectra Energy, effective through January 2012, which provide natural gas transportation to our Pelico system in our Natural Gas Services segment, for approximately 35 MMcf/d.

ConocoPhillips

We have multiple agreements with ConocoPhillips and its affiliates. The agreements include fee-based and percent-of-proceeds gathering and processing arrangements, and gas purchase and gas sales agreements. We anticipate continuing to purchase from and sell to ConocoPhillips and its affiliates in the ordinary course of business.

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

Summary of Transactions with Affiliates

The following table summarizes transactions with affiliates:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(Millions)			
DCP Midstream, LLC:				
Sales of natural gas, propane, NGLs and condensate	$138.5	$124.5	$428.5	$390.0
Transportation, processing and other	$ 7.9	$ 3.5	$ 17.4	$ 10.0
Purchases of natural gas, propane and NGLs	$ 33.6	$ 35.3	$132.1	$121.8
Gains (losses) from commodity derivative activity, net	$ 0.3	$ (0.7)	$ (1.6)	$ (1.0)
General and administrative expense	$ 4.8	$ 4.8	$ 14.3	$ 14.4
Interest expense	$ —	$ —	$ —	$ 0.2
Spectra Energy:				
Transportation, processing and other	$ —	$ —	$ —	$ 0.2
Purchases of natural gas, propane and NGLs	$ 41.8	$ 8.0	$173.5	$ 84.4
Other income	$ —	$ —	$ —	$ 3.0
ConocoPhillips:				
Sales of natural gas, propane, NGLs and condensate	$ 1.5	$ 0.4	$ 11.5	$ 4.7
Transportation, processing and other	$ 1.8	$ 2.1	$ 5.5	$ 6.0
Purchases of natural gas, propane and NGLs	$ 1.6	$ 1.7	$ 5.1	$ 5.3
General and administrative expense	$ —	$ 0.1	$ 0.2	$ 0.2
Unconsolidated affiliates:				
Purchases of natural gas, propane and NGLs	$ —	$ —	$ 3.1	$ 2.4

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

We had balances with affiliates as follows:

	September 30, 2011	December 31, 2010
	(Millions)	
DCP Midstream, LLC:		
Accounts receivable	$ 55.7	$ 60.1
Accounts payable	$ 17.8	$ 27.0
Unrealized gains on derivative instruments — current	$ 0.3	$ 1.3
Unrealized losses on derivative instruments — current	$ (1.4)	$ (1.8)
Spectra Energy:		
Accounts payable	$ 26.9	$ 8.7
ConocoPhillips:		
Accounts receivable	$ 1.4	$ 1.6
Accounts payable	$ 0.5	$ 1.0
Unconsolidated affiliates:		
Accounts payable	$ —	$ 0.9

5. Property, Plant and Equipment

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

	Depreciable Life	September 30, 2011	December 31, 2010
		(Millions)	
Gathering and transmission systems	15 — 30 Years	$ 1,002.2	$ 992.0
Processing, storage, and terminal facilities	20 — 50 Years	536.9	513.2
Other	0 — 30 Years	17.3	12.6
Construction work in progress		99.6	42.1
Property, plant and equipment		1,656.0	1,559.9
Accumulated depreciation		(518.3)	(462.8)
Property, plant and equipment, net		$ 1,137.7	$ 1,097.1

Interest capitalized on construction projects for the nine months ended September 30, 2011 was $0.7 million and for the year ended December 31, 2010 was $0.2 million.

Depreciation expense was $19.0 million and $18.0 million for the three months ended September 30, 2011 and 2010, respectively, and $56.0 million and $53.0 million for the nine months ended September 30, 2011 and 2010, respectively.

Assets Held For Sale — As of September 30, 2011, we had assets held for sale of $3.1 million. Our portion of the proceeds, as a result of the sale of surplus equipment, was $2.3 million based upon our proportionate ownership of 75% in Collbran; part of our Natural Gas Services segment. Title to the equipment will pass to the third party upon removal of the equipment from our premises. As of September 30, 2011, the equipment has been reclassified from property, plant and equipment, to current assets and classified as assets held for sale in our condensed consolidated balance sheets. In addition, we have recorded $3.1 million in other current liabilities in our condensed consolidated balance sheets.

Asset Retirement Obligations — As of September 30, 2011, we had asset retirement obligations of $11.3 million included in other long-term liabilities in the consolidated balance sheet. As of December 31, 2010, we had asset retirement obligations of $10.8 million included in other long-term liabilities in the consolidated balance sheet. Accretion expense was $0.2 million for the three months ended September 30, 2011 and 2010, and $0.5 million and $0.4 million for the nine months ended September 30, 2011 and 2010, respectively.

6. Goodwill and Intangible Assets

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

	September 30, 2011	December 31, 2010
	(Millions)	
Beginning of period	$ 139.3	$ 92.1
Acquisitions	7.6	47.2
End of period	$ 146.9	$ 139.3

The carrying value of goodwill was $70.3 million and $62.8 million as of September 30, 2011 and December 31, 2010 respectively, for our Natural Gas Services segment, $36.9 million as of both periods for our Wholesale Propane Logistics segment, and $39.7 million as of both periods for our NGL logistics segment.

Goodwill increased in 2011 by $7.6 million primarily as a result of a purchase price adjustment related to a contingent payment in conjunction with our 2008 Michigan System acquisition.

We performed our annual goodwill assessment during the quarter and concluded that the entire amount of goodwill on the balance sheet is recoverable. We primarily used a discounted cash flow analysis to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, estimated future cash flows and an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. For certain reporting units, we elected to first assess qualitative factors to determine whether it is more likely than not that the fair value of our reporting units is less than the carrying value. Our annual goodwill impairment tests, including our qualitative analysis, indicated that our reporting units' fair value exceeded the carrying or book value. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value.

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

	September 30, 2011	December 31, 2010
	(Millions)	
Gross carrying amount	$ 129.4	$ 128.7
Accumulated amortization	(14.0)	(9.4)
Intangible assets, net	$ 115.4	$ 119.3

We recorded amortization expense of $1.6 million and $1.2 million for the three months ended September 30, 2011 and 2010, respectively, and $4.6 million and $2.7 million for the nine months ended September 30, 2011 and 2010, respectively. As of September 30, 2011, the remaining amortization periods ranged from approximately 11 years to 24 years, with a weighted-average remaining period of approximately 20 years.

The weighted-average remaining amortization is 19 years for the $33.0 million of intangible assets acquired with our Marysville acquisition.

Estimated future amortization for these intangible assets is as follows:

	Estimated Future Amortization (Millions)
Remainder of 2011	$ 1.5
2012	6.0
2013	6.0
2014	6.0
2015	6.0
Thereafter	89.9
Total	$115.4

7. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

	Percentage of Ownership as of September 30, 2011 and December 31, 2010	Carrying Value as of September 30, 2011	Carrying Value as of December 31, 2010
		(Millions)	
Discovery Producer Services LLC	40%	$ 106.6	$ 104.1
Southeast Texas	33%	115.4	112.6
Other	50%	0.2	0.2
Total investments in unconsolidated affiliates		$ 222.2	$ 216.9

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of $33.2 million and $35.1 million at September 30, 2011 and December 31, 2010, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Discovery.

Earnings from investments in unconsolidated affiliates were as follows:

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010 (a)	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010 (a)
	(Millions)			
Discovery Producer Services LLC	$ 6.9	$ 4.1	$17.1	$ 17.8
Southeast Texas	3.1	4.1	11.5	10.4
Black Lake Pipe Line Company and other	—	—	—	0.8
Total earnings from unconsolidated affiliates	$10.0	$ 8.2	$28.6	$ 29.0

(a) On July 27, 2010, we acquired an additional 5% interest in Black Lake from DCP Midstream, LLC in a transaction among entities under common control, and on July 30, 2010, we acquired an additional 50% interest in Black Lake from an affiliate of BP PLC, bringing our ownership interest in Black Lake to 100%. Prior to our acquisition of an additional 50% interest in Black Lake, we accounted for Black Lake under the equity method of accounting. Subsequent to this transaction, we account for Black Lake as a consolidated subsidiary.

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011 (a)	2010 (b)	2011 (a)	2010 (b)
	(Millions)			
Statements of operations:				
Operating revenue	$282.3	$245.3	$775.3	$763.7
Operating expenses	$261.5	$224.4	$712.5	$690.7
Net income	$ 18.4	$ 20.6	$ 60.1	$ 72.5

(a) The combined financial information excludes the results of Black Lake since we began accounting for Black Lake as a consolidated subsidiary on July 30, 2010.

(b) The combined financial information for the three and nine months ended September 30, 2010 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information similar to the pooling method.

	September 30, 2011 (a)	December 31, 2010 (a) (b)
	(Millions)	
Balance sheets:		
Current assets	$ 129.5	$ 153.0
Long-term assets	712.6	684.9
Current liabilities	(88.6)	(121.4)
Long-term liabilities	(32.3)	(30.3)
Net assets	$ 721.2	$ 686.2

(a) The combined financial information excludes the results of Black Lake, since we began accounting for Black Lake as a consolidated subsidiary effective July 30, 2010.

(b) The combined financial information as of December 31, 2010 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information similar to the pooling method.

8. Fair Value Measurement

Determination of Fair Value

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

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

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

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

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other market participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 10 Risk Management and Hedging Activities.

Valuation Hierarchy

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

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

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

Commodity Derivative Assets and Liabilities

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

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

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

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

Interest Rate Derivative Assets and Liabilities

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

Nonfinancial Assets and Liabilities

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

We utilize fair value on a recurring basis to measure our contingent consideration that is a result of certain acquisitions. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and are classified within Level 3.

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

The following table presents the financial instruments carried at fair value as of September 30, 2011 and December 31, 2010, by consolidated balance sheet caption and by valuation hierarchy as described above:

	September 30, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(Millions)							
Current assets (a):								
Commodity derivatives	$ —	$ 3.6	$ 1.4	$ 5.0	$ —	$ 1.6	$ 0.3	$ 1.9
Interest rate derivatives	$ —	$ 0.6	$ —	$ 0.6	$ —	$ —	$ —	$ —
Long-term assets (b):								
Commodity derivatives	$ —	$ 11.7	$ 0.2	$ 11.9	$ —	$ 1.1	$ 0.3	$ 1.4
Current liabilities (c):								
Commodity derivatives	$ —	$(15.6)	$ (0.7)	$ (16.3)	$ —	$(25.9)	$ (0.1)	$ (26.0)
Interest rate derivatives	$ —	$(17.3)	$ —	$ (17.3)	$ —	$(17.0)	$ —	$ (17.0)
Long-term liabilities (d):								
Commodity derivatives	$ —	$(15.5)	$ —	$ (15.5)	$ —	$(39.9)	$ (0.5)	$ (40.4)
Interest rate derivatives	$ —	$ (5.8)	$ —	$ (5.8)	$ —	$ (9.9)	$ —	$ (9.9)

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

Changes in Level 3 Fair Value Measurements

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

Table of Contents

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

	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(Millions)			
Three months ended September 30, 2011 (a):				
Beginning balance	$ 0.6	$ 0.3	$ (1.2)	$ (0.3)
Net realized and unrealized gains (losses) included in earnings	1.2	2.4	(2.1)	0.3
Transfers into Level 3 (b)	—	—	—	—
Transfers out of Level 3 (b)	—	(2.5)	—	—
Settlements	(0.4)	—	2.6	—
Ending balance	$ 1.4	$ 0.2	$ (0.7)	$ —
Net unrealized gains (losses) still held included in earnings (c)	$ 1.0	$ —	$ (0.3)	$ 0.3
Three months ended September 30, 2010:				
Beginning balance	$ 0.8	$ 1.8	$ (0.1)	$ (0.2)
Net realized and unrealized (losses) gains included in earnings	(0.1)	(1.1)	0.1	0.2
Transfers into Level 3 (b)	—	—	—	—
Transfers out of Level 3 (b)	(0.4)	—	—	—
Purchases, Issuances and Settlements, net	—	—	—	—
Ending balance	$ 0.3	$ 0.7	$ —	$ —
Net unrealized gains (losses) still held included in earnings (c)	$ 0.2	$ (0.9)	$ —	$ —

(a) There were no purchases, issuances and sales for the three months ended September 30, 2011.
(b) Amounts transferred in and amounts transferred out are reflected at fair value as of the end of the period.
(c) Represents the amount of total gains or losses for the period, included in gains or losses from commodity derivative activity, net, attributable to change in unrealized gains or losses relating to assets and liabilities classified as Level 3 that are still held as of September 30, 2011 and 2010.

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

	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(Millions)			
Nine months ended September 30, 2011 (a):				
Beginning balance	$ 0.3	$ 0.3	$ (0.1)	$ (0.5)
Net realized and unrealized gains (losses) included in earnings	1.4	1.0	(0.7)	0.5
Transfers into Level 3 (b)	—	—	—	—
Transfers out of Level 3 (b)	—	(1.1)	—	—
Settlements	(0.3)	—	0.1	—
Ending balance	$ 1.4	$ 0.2	$ (0.7)	$ —
Net unrealized gains (losses) still held included in earnings (c)	$ 1.4	$ (0.1)	$ (0.7)	$ 0.3
Nine months September 30, 2010:				
Beginning balance	$ 0.4	$ 0.2	$ (0.8)	$ (0.4)
Net realized and unrealized gains included in earnings	0.3	0.5	0.2	0.4
Transfers into Level 3 (b)	—	—	—	—
Transfers out of Level 3 (b)	(0.4)	—	—	—
Purchases, Issuances and Settlements, net	—	—	0.6	—
Ending balance	$ 0.3	$ 0.7	$ —	$ —
Net unrealized gains (losses) still held included in earnings (c)	$ 0.3	$ 0.5	$ —	$ —

(a) There were no purchases, issuances and sales for the nine months ended September 30, 2011.
(b) Amounts transferred in and amounts transferred out are reflected at fair value as of the end of the period.
(c) Represents the amount of total gains or losses for the period, included in gains or losses from commodity derivative activity, net, attributable to change in unrealized gains or losses relating to assets and liabilities classified as Level 3 that are still held as of September 30, 2011 and 2010.

During the nine months ended September 30, 2010, we recognized the fair value of our contingent consideration, which is classified as Level 3, in relation to our acquisition of an additional 5% interest in Collbran, from Delta Petroleum Corporation of approximately $0.5 million, which we recorded to other current liabilities in our condensed consolidated balance sheet.

During the three and nine months ended September 30, 2011, we had no significant transfers into or out of Levels 1 and 2. To qualify as a transfer, the asset or liability must have existed in the previous reporting period and moved into a different level during the current period.

Estimated Fair Value of Financial Instruments

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

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

The fair value of accounts receivable and accounts payable are not materially different from their carrying amounts because of the short-term nature of these instruments or the stated rates approximating market rates. Unrealized gains and unrealized losses on derivative instruments are carried at fair value. The carrying and fair values of outstanding balances under our Credit Agreement are $476.0 million and $473.0 million, respectively, as of September 30, 2011, and $398.0 million and $388.9 million, respectively, as of December 31, 2010. The carrying and fair values of our 3.25% Senior Notes are $250.0 million and $247.7 million, respectively, as of September 30, 2011 and December 31, 2010. We determine the fair value of our credit facility borrowings based upon the discounted present value of expected future cash flows, taking into account the difference between the contractual borrowing spread and the spread for similar credit facilities available in the marketplace. We determine the fair value of our fixed-rate debt based on quotes obtained from bond dealers.

9. Debt

Long-term debt was as follows:

	September 30, 2011	December 31, 2010
	(Millions)	
Credit Agreement		
Revolving credit facility, weighted-average variable interest rate of 0.75% and 1.14%, respectively, and net effective interest rate of 4.20% and 4.28%, respectively, due June 21, 2012 (a)	$ 476.0	$ 398.0
Debt Securities		
Issued September 30, 2010, interest at 3.25% payable semi-annually, due October 1, 2015	250.0	250.0
Unamortized discount	(0.2)	(0.2)
Total debt	725.8	647.8
Current maturities	(476.0)	—
Total long-term debt	$ 249.8	$ 647.8

(a) $450.0 million of debt has been swapped to a fixed-rate obligation with effective fixed-rates ranging from 2.94% to 5.19%, for a net effective rate of 4.20% on the $476.0 million of outstanding debt under our revolving credit facility as of September 30, 2011.

Credit Agreement

We have an $850.0 million revolving credit facility that matures June 21, 2012, or the Credit Agreement.

As of September 30, 2011 and December 31, 2010, we had $1.1 million and $32.1 million, respectively, of letters of credit issued under the Credit Agreement. As of September 30, 2011, the unused capacity under the revolving credit facility was $372.9 million, of which approximately $346.0 million was available for general working capital purposes.

Our borrowing capacity is limited at September 30, 2011 by the Credit Agreement's financial covenant requirements. Except in the case of a default, amounts borrowed under our credit facility will not mature prior to the June 21, 2012 maturity date.

Under the Credit Agreement, indebtedness under the revolving credit facility bears interest at either: (1) the higher of Wells Fargo Bank's prime rate or the Federal Funds rate plus 0.50%; or (2) LIBOR plus an applicable margin, which ranges from 0.23% to 0.575% dependent upon our credit rating. The revolving credit facility incurs an annual facility fee of 0.07% to 0.175% depending on our credit rating. This fee is paid on drawn and undrawn portions of the revolving credit facility.

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

The Credit Agreement requires us to maintain a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Credit Agreement) of not more than 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of asset acquisitions in the midstream energy business of not more than 5.5 to 1.0.

Debt Securities

On September 30, 2010, we issued $250.0 million of 3.25% Senior Notes due October 1, 2015. We received proceeds of $247.7 million, which are net of underwriters' fees, related expenses and unamortized discounts of $1.5 million, $0.6 million and $0.2 million, respectively, which we used to repay funds borrowed under the revolver portion of our Credit Facility. Interest on the notes is paid semi-annually on April 1 and October 1 of each year, with the first payment made on April 1, 2011. The notes will mature on October 1, 2015, unless redeemed prior to maturity. The underwriters' fees and related expenses are deferred in other long-term assets in our condensed consolidated balance sheets and will be amortized over the term of the notes.

The notes are senior unsecured obligations, ranking equally in right of payment with other unsecured indebtedness, including indebtedness under our Credit Facility. We are not required to make mandatory redemption or sinking fund payments with respect to these notes. The securities are redeemable at a premium at our option.

The future maturities of long-term debt in the year indicated are as follows:

	Debt Maturities (Millions)
2012	$ —
2013	—
2014	—
2015	250.0
Thereafter	—
Unamortized discount	(0.2)
Total	$ 249.8

Other Agreements

As of September 30, 2011, we had a contingent letter of credit for up to $10.0 million, on which we pay a fee of 0.50% per annum. This facility reduces the amount of cash we may be required to post as collateral. As of September 30, 2011, we had no letters of credit issued on this facility. Any letters of credit issued on this facility will incur a fee of 1.75% per annum and will not reduce the available capacity under our Credit Facility.

10. Risk Management and Hedging Activities

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

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

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of our gathering, processing, sales and storage activities. For gathering and processing and storage services, we may receive fees or commodities as payment for these services, depending on the contract type. We enter into derivative financial instruments to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices associated with our gathering, processing and sales activities, thereby stabilizing our cash flows. We have mitigated a portion of our expected commodity price risk associated with our gathering, processing and sales activities through 2016 with commodity derivative instruments. Given the limited liquidity and tenor of the NGL derivatives market, we have primarily utilized crude oil swaps to mitigate a portion of our commodity price exposure for NGLs. For the nearer tenor where there is greater liquidity in the NGL derivatives market, we have periodically also utilized NGL derivatives. Historically, prices of NGLs have been generally related to the price of crude oil, with some exceptions, notably in late 2008 to early 2009, when NGL pricing was at a greater discount to crude oil pricing. When the relationship of NGL prices to crude oil prices is at a discount to historical ranges, we experience additional exposure as a result of the relationship. When our crude oil swaps become short-term in nature, we have periodically converted certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps. Our crude oil and NGL transactions are primarily accomplished through the use of forward contracts that effectively exchange our floating price risk for a fixed price. We also utilize crude oil costless collars that minimize our floating price risk by establishing a fixed price floor and a fixed price ceiling. However, the type of instrument that we use to mitigate a portion of our risk may vary depending upon our risk management objective. These transactions are not designated as hedging instruments for accounting purposes and the change in fair value is reflected within our condensed consolidated statements of operations as a gain or a loss on commodity derivative activity.

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

Our Wholesale Propane Logistics segment is generally designed to establish stable margins by entering into supply arrangements that specify prices based on established floating price indices and by entering into sales agreements that provide for floating prices that are tied to our variable supply costs plus a margin. To the extent possible, we match the pricing of our supply portfolio to our sales portfolio in order to lock in value and reduce our overall commodity price risk. However, to the extent that we carry propane inventories or our sales and supply arrangements are not aligned, we are exposed to market variables and commodity price risk. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. While the majority of our sales and purchases in this segment are index-based, occasionally, we may enter into fixed price sales agreements in the event that a retail propane distributor desires to purchase propane from us on a fixed price basis. In such cases, we may manage this risk with derivatives that allow us to swap our fixed price risk to market index prices that are matched to our market index supply costs. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories. These transactions are not designated as hedging instruments for accounting purposes and the change in value is reflected in the current period within our condensed consolidated statements of operations as a gain or loss on commodity derivative activity.

Our portfolio of commodity derivative activity is primarily accounted for using the mark-to-market method of accounting, whereby changes in fair value are recorded directly to the condensed consolidated statements of operations; however, depending upon our risk profile and objectives, in certain limited cases, we may execute transactions that qualify for the hedge method of accounting.

Commodity Cash Flow Hedges — Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for derivatives that manage our commodity price risk. Prior to July 1, 2007, we used commodity swaps to mitigate a portion of the risk of market fluctuations in the price of NGLs, natural gas and condensate. Given our election to discontinue using the hedge method of accounting, the remaining net losses deferred in accumulated other comprehensive income, or AOCI, relative to cash flow hedges are reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the underlying transactions impact earnings.

On January 1, 2011, we acquired a 33.33% interest in Southeast Texas for $150.0 million and account for our interest as an equity method investment. Southeast Texas commenced an expansion project to build an additional storage cavern. In order for storage facilities to remain operational, a minimum level of base gas must be maintained in each storage cavern. Upon completion of the expansion project, Southeast Texas will be required to purchase a significant amount of base gas to bring the storage cavern to operation. To mitigate the risk associated with this forecasted purchase of natural gas, Southeast Texas executed derivative financial instruments which have been designated as cash flow hedges. Any effective changes in fair value of these derivative instruments will be deferred in AOCI until the underlying purchase of inventory occurs. While the cash paid or received upon settlement of these hedges will economically offset the cash required to purchase the base gas, any deferred gain or loss at the time of the purchase will remain in AOCI until such time that the cavern is emptied and the base gas is sold. We recognize our proportionate share of the Southeast Texas base gas commodity derivative activity in AOCI, with corresponding adjustments to our investment in Southeast Texas.

Interest Rate Risk

We mitigate a portion of our interest rate risk with interest rate swaps and forward-starting interest rate swaps that reduce our exposure to market rate fluctuations by converting variable interest rates on our existing debt to fixed interest rates and locking in rates on our anticipated future fixed-rate debt, respectively. The interest rate swap agreements convert the interest rate associated with the indebtedness outstanding under our revolving credit facility to a fixed-rate obligation, thereby reducing the exposure to market rate fluctuations. The forward-starting interest rate swap agreements lock in the interest rate associated with our anticipated future fixed-rate debt, thereby reducing the exposure to market rate fluctuations prior to issuance.

At September 30, 2011, we had interest rate swap agreements totaling $450.0 million, of which we have designated $425.0 million as cash flow hedges and account for the remaining $25.0 million under the mark-to-market method of accounting. As we generally expect to have variable-rate debt levels equal to or exceeding our swap positions during their term, the entire $450.0 million of these arrangements mitigate our interest rate risk through June 2012, with $150.0 million extending from June 2012 through June 2014. Based on our current operations we believe our interest rate swap agreements mitigate our interest rate risk associated with our variable-rate debt.

At September 30, 2011, we had forward-starting interest rate swap agreements totaling $195.0 million, which we have designated as cash flow hedges. As we anticipate entering into future fixed-rate debt at levels equal to or exceeding our forward-starting swap positions during their term, the entire $195.0 million of these arrangements mitigate a portion of our interest rate risk through the term of our anticipated debt into 2022. Based on our current operations we believe our forward-starting interest rate swap agreements mitigate a portion of our interest rate risk associated with our anticipated future fixed-rate debt.

We have designated $425.0 million of our interest rate swap agreements and $195.0 million of our forward-starting interest rate swaps as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in AOCI in the condensed consolidated balance sheets and are reclassified into earnings as the hedged transactions impact earnings. The effect that these swaps have on our condensed consolidated financial statements, as well as the effect that is expected over the upcoming 12 months is summarized in the charts below. However, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings. Ineffective portions of changes in fair value are recognized in earnings.

As of September 30, 2011, $275.0 million of the interest rate swap agreements reprice prospectively approximately every 90 days and the remaining $175.0 million of the agreements reprice prospectively approximately every 30 days. Under the terms of the interest rate swap agreements, we pay fixed-rates ranging from 2.94% to 5.19%, and receive interest payments based on the three-month and one-month LIBOR. Under the terms of the forward-starting interest rate swap agreements, we will pay fixed- rates ranging from 2.15% to 2.598%, and receive interest payments approximating 10-year U.S. Treasury rates. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense.

Contingent Credit Features

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

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

- If we were to have an effective event of default under our Credit Agreement that occurs and is continuing, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative liability positions.
- In the event that we or DCP Midstream, LLC were to be downgraded below investment grade by at least one of the major credit rating agencies, certain of our ISDA counterparties have the right to reduce our collateral threshold to zero, potentially requiring us to fully collateralize any commodity contracts in a net liability position.
- Additionally, in some cases, our ISDA contracts contain cross-default provisions that could constitute a credit-risk related contingent feature. These provisions apply if we default in making timely payments under those agreements and the amount of the default is above certain predefined thresholds, which are significantly high and are generally consistent with the terms of our Credit Agreement. As of September 30, 2011, we are not a party to any agreements that would be subject to these provisions other than our credit agreement.

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

Depending upon the movement of commodity prices and interest rates, each of our individual contracts with counterparties to our commodity derivative instruments or to our interest rate swap instruments are in either a net asset or net liability position. As of September 30, 2011, we had $30.4 million of individual commodity derivative contracts that contain credit-risk related contingent features that were in a net liability position, and have not posted any cash collateral relative to such positions. If a credit-risk related event were to occur and we were required to net settle our position with an individual counterparty, our ISDA contracts permit us to net all outstanding contracts with that counterparty, whether in a net asset or net liability position, as well as any cash collateral already posted. As of September 30, 2011, if a credit-risk related event were to occur we may be required to post additional collateral. Additionally, although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of September 30, 2011, if a credit-risk related event were to occur, the net liability position would be partially offset by contracts in a net asset position reducing our net liability to $20.7 million.

As of September 30, 2011, we had $23.1 million of individual interest rate swap instruments that were in a net liability position and were subject to credit-risk related contingent features. Although our interest rate swap instruments were in a net liability position as of September 30, 2011, if a credit-risk related event were to occur, the net liability position would be partially offset by contracts in a net asset position reducing our net liability to $22.5 million. If we were to have a default of any of our covenants to our Credit Agreement, that occurs and is continuing, the counterparties to our swap instruments have the right to request that we net settle the instrument in the form of cash.

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

Collateral

As of September 30, 2011, we had a contingent letter of credit facility for up to $10.0 million, on which we have no letters of credit issued. DCP Midstream, LLC had issued and outstanding parental guarantees totaling $70.0 million in favor of certain counterparties to our commodity derivative instruments. This contingent letter of credit facility and the parental guarantees reduce the amount of cash we may be required to post as collateral. As of September 30, 2011, we had no cash collateral posted with counterparties to our commodity derivative instruments.

Summarized Derivative Information

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

	September 30, 2011	December 31, 2010
	(Millions)	
Commodity cash flow hedges:		
Net deferred losses in AOCI	$ (1.3)	$ (0.3)
Interest rate cash flow hedges:		
Net deferred losses in AOCI	(21.5)	(27.4)
Total AOCI	$ (22.8)	$ (27.7)

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

Balance Sheet Line Item	September 30, 2011	December 31, 2010
	(Millions)	
Derivative Assets Designated as Hedging Instruments:		
Interest rate derivatives:		
Unrealized gains on derivative instruments – current	$ 0.6	$ —
Unrealized gains on derivative instruments – long term	—	—
	$ 0.6	$ —
Derivative Assets Not Designated as Hedging Instruments:		
Commodity derivatives:		
Unrealized gains on derivative instruments – current	$ 5.0	$ 1.9
Unrealized gains on derivative instruments – long term	11.9	1.4
	$ 16.9	$ 3.3
Interest rate derivatives:		
Unrealized gains on derivative instruments – current	$ —	$ —
Unrealized gains on derivative instruments – long term	—	—
	$ —	$ —

Balance Sheet Line Item	September 30, 2011	December 31, 2010
	(Millions)	
Derivative Liabilities Designated as Hedging Instruments:		
Interest rate derivatives:		
Unrealized losses on derivative instruments – current	$ (16.6)	$ (12.2)
Unrealized losses on derivative instruments – long term	(5.8)	(5.4)
	$ (22.4)	$ (17.6)
Derivative Liabilities Not Designated as Hedging Instruments:		
Commodity derivatives:		
Unrealized losses on derivative instruments – current	$ (16.3)	$ (26.0)
Unrealized losses on derivative instruments – long term	(15.5)	(40.4)
	$ (31.8)	$ (66.4)
Interest rate derivatives:		
Unrealized losses on derivative instruments – current	$ (0.7)	$ (4.8)
Unrealized losses on derivative instruments – long term	—	(4.5)
	$ (0.7)	$ (9.3)

The following table summarizes the impact on our condensed consolidated balance sheets and condensed consolidated statements of operations of our derivative instruments that are accounted for using the cash flow hedge method of accounting.

	(Loss) Recognized in AOCI on Derivatives — Effective Portion		(Loss) Gain Reclassified From AOCI to Earnings — Effective Portion		Gain (Loss) Recognized in Income on Derivatives — Ineffective Portion and Amount Excluded From Effectiveness Testing	
	Three Months Ended September 30,					
	2011	2010	2011	2010	2011	2010
	(Millions)		(Millions)		(Millions)	
Interest rate derivatives	$ (5.3)	$ (4.8)	$ (5.1)	$ (5.4)(a)	$ (0.1)	$ — (a)(c)
Commodity derivatives	$ (0.2)	$ —	$ (0.1)	$ 0.1(b)	$ —	$ — (b)(c)

(a) Included in interest expense in our condensed consolidated statements of operations.
(b) Included in sales of natural gas, propane, NGLs and condensate in our condensed consolidated statements of operations.
(c) For the three months ended September 30, 2011 and 2010, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring or as a result of exclusion from effectiveness testing.

	(Loss) Recognized in AOCI on Derivatives —Effective Portion		(Loss) Reclassified From AOCI to Earnings — Effective Portion		Gain (Loss) Recognized in Income on Derivatives — Ineffective Portion and Amount Excluded From Effectiveness Testing		Deferred (Losses) in AOCI Expected to be Reclassified into Earnings Over the Next 12 Months
	Nine Months Ended September 30,						
	2011	2010	2011	2010	2011	2010	
	(Millions)		(Millions)		(Millions)		(Millions)
Interest rate derivatives	$ (9.5)	$ (18.2)	$ (15.4)	$ (16.6)(a)	$ (0.2)	$ — (a)(c)	$ (16.2)
Commodity derivatives	$ (0.3)	$ —	$ (0.2)	$ (0.3)(b)	$ —	$ — (b)(c)	$ (0.1)

(a) Included in interest expense in our condensed consolidated statements of operations.
(b) Included in sales of natural gas, propane, NGLs and condensate in our condensed consolidated statements of operations.
(c) For the nine months ended September 30, 2011 and 2010, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring or as a result of exclusion from effectiveness testing.

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

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

Commodity Derivatives: Statements of Operations Line Item	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(Millions)			
Third party:				
Realized	$ (7.8)	$ 2.6	$ (22.7)	$ 0.5
Unrealized	59.6	(18.4)	48.8	12.5
Gains (losses) from commodity derivative activity, net	$ 51.8	$ (15.8)	$ 26.1	$ 13.0
Affiliates:				
Realized	$ (0.1)	$ (0.5)	$ (1.1)	$ (0.4)
Unrealized	0.4	(0.2)	(0.5)	(0.6)
Gains (losses) from commodity derivative activity, net — affiliates	$ 0.3	$ (0.7)	$ (1.6)	$ (1.0)

Interest Rate Derivatives: Statements of Operations Line Item	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(Millions)			
Third party:				
Realized losses	$ (1.2)	$ —	$ (3.5)	$ —
Unrealized gains (losses)	1.3	(0.1)	4.1	(0.1)
Interest expense	$ 0.1	$ (0.1)	$ 0.6	$ (0.1)

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

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

	September 30, 2011		
	Crude Oil	Natural Gas	Natural Gas Liquids
Year of Expiration	Net Long (Short) Position (Bbls)	Net Long (Short) Position (MMBtu)	Net Long (Short) Position (Bbls)
2011	(87,058)	(618,800)	(379,887)
2012	(904,171)	(366,000)	(145,082)
2013	(947,249)	(365,000)	—
2014	(547,500)	(365,000)	—
2015	(365,000)	—	—
2016	(183,000)	—	—

	September 30, 2010		
	Crude Oil	Natural Gas	Natural Gas Liquids
Year of Expiration	Net Long (Short) Position (Bbls)	Net Long (Short) Position (MMBtu)	Net Long (Short) Position (Bbls)
2010	(245,180)	(624,300)	(20,524)
2011	(949,000)	(365,000)	6,810
2012	(777,750)	(366,000)	—
2013	(748,250)	(365,000)	—
2014	(547,500)	(365,000)	—
2015	(182,500)	—	—

We periodically enter into interest rate swap agreements to mitigate a portion of our floating rate interest exposure. As of September 30, 2011, we have swaps with notional values between $25.0 million and $80.0 million, which, in aggregate, exchange $450.0 million of our floating rate obligation to a fixed-rate obligation through June 2012, with $150.0 million extending from June 2012 through June 2014.

11. Partnership Equity and Distributions

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

On August 17, 2011, we entered into an equity distribution agreement with Citigroup Global Markets Inc., or Citi. The agreement provides for the offer and sale from time to time through Citi, our sales agent, common units having an aggregate offering amount of up to $150 million. During the three months ended September 30, 2011, we issued 345,031 of our common units pursuant to this equity distribution agreement. We received proceeds of $12.5 million from the issuance of these common units, net of commissions and offering costs of $0.5 million, which were used to finance growth opportunities.

In September 2011, we issued 4,000 common limited partner units, from our long-term incentive plan, or LTIP, to non-employee directors as compensation for their service during 2011.

In March 2011, we issued 3,596,636 common limited partner units at $40.55 per unit. We received proceeds of $139.7 million, net of offering costs.

In February 2011, we issued 8,399 common limited partner units, from our LTIP to employees as compensation for their service during 2010, 2009 and 2008.

In November 2010, we issued 2,875,000 common limited partner units at $34.96 per unit. We received proceeds of $96.2 million, net of offering costs.

In September 2010, we issued 5,200 common limited partner units, from our LTIP to non-employee directors as compensation for their service during 2010.

In August 2010, we issued 2,990,000 common limited partner units at $32.57 per unit. We received proceeds of $93.1 million, net of offering costs.

On May 26, 2010, we filed a universal shelf registration statement on Form S-3 with the SEC with a maximum aggregate offering amount of $1.5 billion, to replace an existing shelf registration statement. The universal shelf registration statement will allow us to register and issue additional partnership units and debt securities.

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

- less the amount of cash reserves established by the general partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments or other agreements; and
  - provide funds for distributions to the unitholders and to our general partner for any one or more of the next four quarters;
- plus, if our general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination of Available Cash for the quarter.

General Partner Interest and Incentive Distribution Rights — The general partner is entitled to a percentage of all quarterly distributions equal to its general partner interest of approximately 1% and limited partner interest of 1% as of September 30, 2011. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest.

The incentive distribution rights held by the general partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest level. The general partner's incentive distribution rights were not reduced as a result of our common limited partner unit issuances, and will not be reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its current general partner interest. Please read the *Distributions of Available Cash after the Subordination Period* sections below for more details about the distribution targets and their impact on the general partner's incentive distribution rights.

Distributions of Available Cash after the Subordination Period — Our partnership agreement, after adjustment for the general partner's relative ownership level, requires that we make distributions of Available Cash from operating surplus for any quarter after the subordination period, which ended in February 2009, in the following manner:

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

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

The following table presents our cash distributions paid in 2011 and 2010:

Payment Date	Per Unit Distribution	Total Cash Distribution (Millions)
August 12, 2011	$ 0.6325	$ 34.0
May 13, 2011	$ 0.6250	$ 33.4
February 14, 2011	$ 0.6175	$ 30.0
November 12, 2010	$ 0.6100	$ 27.4
August 13, 2010	$ 0.6100	$ 25.3
May 14, 2010	$ 0.6000	$ 24.6
February 12, 2010	$ 0.6000	$ 24.6

12. Equity-Based Compensation

On November 28, 2005, the board of directors of our General Partner adopted the LTIP, for employees, consultants and directors of our General Partner and its affiliates who perform services for us. The LTIP provides for the grant of limited partner units, or LPUs, phantom units, unit options and substitute awards, and, with respect to unit options and phantom units, the grant of dividend equivalent rights, or DERs. Subject to adjustment for certain events, an aggregate of 850,000 LPUs may be issued and delivered pursuant to awards under the LTIP. Awards that are canceled or forfeited, or are withheld to satisfy the General Partner’s tax withholding obligations, are available for delivery pursuant to other awards. The LTIP is administered by the compensation committee of the General Partner’s board of directors. All awards are subject to cliff vesting, with the exception of the Phantom Units issued to directors in conjunction with our initial public offering, which are subject to graded vesting provisions.

Prior to February 18, 2011, substantially all equity-based awards were accounted for as liability awards. Effective February 18, 2011, the Modification Date, we have the intent and ability to settle certain awards within our control in units and therefore modified the accounting for these awards. We now classify them as equity awards based on their re-measured fair value. The fair value was determined based on the closing price of our common units on the Modification Date. Such modification resulted in a reclassification of $1.9 million from share-based compensation liability to additional paid-in capital on the Modification Date. Compensation expense on unvested equity awards as of the Modification Date will be recognized ratably over each remaining vesting period.

We will continue to account for other awards, which are subject to settlement in cash as liability awards. Compensation expense on these awards is recognized ratably over each vesting period, and will be re-measured each reporting period for all awards outstanding until the units are vested. The fair value of all liability awards is determined based on the closing price of our common units at each measurement date.

The reclassification of the affected awards does not impact our accounting for dividend equivalent rights as these instruments will continue to be settled in cash and therefore retain their share-based compensation liability classification.

13. Income Taxes

We are structured as a master limited partnership, which is a pass-through entity for federal income tax purposes. On December 30, 2010, we acquired all of the interests in Marysville Hydrocarbons Holdings, LLC, an entity that owns a taxable C-Corporation consolidated return group. We estimated $35.0 million of deferred tax liabilities resulting from built-in tax gains recognized in the transaction and recorded this in our preliminary purchase price allocation as of December 31, 2010.

On January 4, 2011, we merged two wholly-owned subsidiaries of Marysville Hydrocarbons Holding, LLC and converted the combined entity’s organizational structure from a corporation to a limited liability company. This conversion to a limited liability company triggered the deferred tax liabilities resulting from built-in tax gains to become currently payable. Accordingly, the estimated $35.0 million of deferred tax liabilities at December 31, 2010 became currently payable on January 4, 2011. On April 18, 2011, we made an estimated federal tax payment of $29.3 million related to our $35.0 million tax liability that resulted from our acquisition of Marysville. The remaining $5.7 million estimated tax payable is included in other current liabilities in our condensed consolidated balance sheet as of September 30, 2011.

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

14. Net Income or Loss per Limited Partner Unit

Basic net income per limited partner unit is computed based on the weighted average number of units outstanding during the period. Diluted net income per limited partner unit is computed based on the weighted average number of units plus the effect of dilutive potential units outstanding during the period using the two-class method. Dilutive potential units include outstanding performance units, phantom units and restricted units. The dilutive effect of unit-based awards was 74,299 equivalent units and 61,573 equivalent units during the three and nine month periods ended September 30, 2011, respectively. There were no dilutive unit-based awards in the three and nine month periods ended September 30, 2010.

15. Commitments and Contingent Liabilities

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

Insurance — We renewed our insurance policies in May, June and July 2011 for the 2011-2012 insurance year. We contract with third party and affiliate insurers for: (1) automobile liability insurance for all owned, non-owned and hired vehicles; (2) general liability insurance; (3) excess liability insurance above the established primary limits for general liability and automobile liability insurance; and (4) property insurance, which covers replacement value of real and personal property and includes business interruption/extra expense. These renewals have not resulted in any material change to the premiums we are contracted to pay in the 2011-2012 insurance year compared with the 2010-2011 insurance year. We are jointly insured with DCP Midstream, LLC for directors and officers insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies that are of similar size to us and with similar types of operations.

Our insurance on Discovery for the 2011-2012 insurance year includes general and excess liability, onshore property damage, including named windstorm and business interruption, and offshore non-wind property and business interruption insurance. The availability of offshore named windstorm property and business interruption insurance has been significantly reduced over the past few years as a result of higher industry-wide damage claims. Additionally, the named windstorm property and business interruption insurance that is available comes at uneconomic premium levels, higher deductibles and lower coverage limits. As such, Discovery has elected to not purchase offshore named windstorm property and business interruption insurance coverage for the 2011-2012 insurance year.

Environmental — As previously reported, during the first quarter of 2011, we discovered excess emissions at our East Texas gas plant. We met with the Texas Commission on Environmental Quality, or TCEQ, in April 2011 to discuss this matter and included these issues in Title V reports we submitted to the State. In August 2011, the TCEQ conducted a standard inspection at the East Texas gas plant to evaluate compliance with applicable air quality requirements. On August 31, 2011, the TCEQ issued us a Notice of Violation and a Notice of Enforcement citing a number of alleged violations of terms and requirements of the facility air permit. We responded to the Notice of Violation on September 28, 2011, including the implemented measures to ensure the facility is in compliance with the relevant air permit terms and conditions. We responded to the Notice of Enforcement on October 14, 2011, including a description of the measures that have been implemented, and will be implemented at the facility to ensure compliance with the relevant air permit terms and conditions. We expect that the TCEQ will assess a civil penalty in relation to the Notice of Enforcement, although we have not yet received a proposed penalty assessment from the agency. We do not believe the ultimate resolution of this matter will have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Indemnification — DCP Midstream, LLC has indemnified us for certain potential environmental claims, losses and expenses associated with the operation of the assets of certain of our predecessors.

Table of Contents

16. Business Segments

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

Natural Gas Services — Our Natural Gas Services segment provides services that include gathering, compressing, treating, processing, fractionating, transporting and storing natural gas. The segment consists of our Northern Louisiana system, our Southern Oklahoma system, our Wyoming system, our Michigan system, our 33.33% interest in the Southeast Texas system, our 50.1% interest in the East Texas system, our 75% interest in the Colorado system, and our 40% limited liability company interest in Discovery.

Wholesale Propane Logistics — Our Wholesale Propane Logistics segment provides services that include the receipt of propane by pipeline, rail or ship to our terminals that deliver the product to retail distributors. The segment consists of six owned rail terminals, one owned marine import terminal, one leased marine terminal, one pipeline terminal and access to several open-access pipeline terminals.

NGL Logistics — Our NGL Logistics segment provides services that include transportation, storage and fractionation of NGLs. The segment consists of the Seabreeze and Wilbreeze intrastate NGL pipelines, the Wattenberg and Black Lake interstate NGL pipelines, the NGL storage facility in Michigan and the DJ Basin NGL Fractionators in Colorado.

These segments are monitored separately by management for performance against our internal forecast and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. Gross margin is a performance measure utilized by management to monitor the business of each segment.

The following tables set forth our segment information:

	Three Months Ended September 30, 2011					
	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other	Eliminations (f)	Total
	(Millions)					
Total operating revenue	$ 268.5	$ 100.1	$ 14.7	$ —	$ —	$ 383.3
Total purchases	(163.2)	(94.1)	—	—	—	(257.3)
Gross margin (a)	$ 105.3	$ 6.0	$ 14.7	$ —	$ —	$ 126.0
Operating and maintenance expense	(22.8)	(3.2)	(5.5)	—	—	(31.5)
Depreciation and amortization expense	(17.5)	(0.7)	(2.4)	—	—	(20.6)
General and administrative expense	—	—	—	(9.4)	—	(9.4)
Other income	—	—	0.2	—	—	0.2
Earnings from unconsolidated affiliates	10.0	—	—	—	—	10.0
Interest expense	—	—	—	(8.6)	—	(8.6)
Income tax expense (b)	—	—	—	(0.2)	—	(0.2)
Net income (loss)	75.0	2.1	7.0	(18.2)	—	65.9
Net loss attributable to noncontrolling interests	0.4	—	—	—	—	0.4
Net income (loss) attributable to partners	$ 75.4	$ 2.1	$ 7.0	$(18.2)	$ —	$ 66.3
Non-cash derivative mark-to-market (c)	$ 59.9	$ 0.1	$ —	$ (0.7)	$ —	$ 59.3

Table of Contents

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

	Three Months Ended September 30, 2010				
	Natural Gas Services (e)	Wholesale Propane Logistics	NGL Logistics	Other	Total
	(Millions)				
Total operating revenue	$ 167.9	$ 65.9	$ 6.1	$ —	$ 239.9
Total purchases	(135.1)	(62.9)	(2.2)	—	(200.2)
Gross margin (a)	$ 32.8	$ 3.0	$ 3.9	$ —	$ 39.7
Operating and maintenance expense	(15.0)	(3.1)	(1.1)	—	(19.2)
Depreciation and amortization expense	(17.3)	(1.0)	(0.8)	(0.1)	(19.2)
General and administrative expense	—	—	—	(8.2)	(8.2)
Step acquisition — equity interest re-measurement gain	—	—	9.1	—	9.1
Other income	0.5	—	—	—	0.5
Earnings from unconsolidated affiliates	8.2	—	—	—	8.2
Interest expense	—	—	—	(7.5)	(7.5)
Income tax expense (b)	—	—	—	(0.1)	(0.1)
Net income (loss)	9.2	(1.1)	11.1	(15.9)	3.3
Net income attributable to noncontrolling interests	(3.3)	—	—	—	(3.3)
Net income (loss) attributable to partners	$ 5.9	$ (1.1)	$ 11.1	$(15.9)	$ —
Non-cash derivative mark-to-market (c)	$ (18.0)	$ (0.5)	$ —	$ (0.2)	$ (18.7)

	Nine Months Ended September 30, 2011					
	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other	Eliminations (f)	Total
	(Millions)					
Total operating revenue	$ 690.4	$ 452.1	$ 42.3	$ —	$ (2.2)	$1,182.6
Total purchases	(486.0)	(418.1)	(4.7)	—	2.2	(906.6)
Gross margin (a)	$ 204.4	$ 34.0	$ 37.6	$ —	$ —	$ 276.0
Operating and maintenance expense	(55.0)	(11.0)	(11.3)	—	—	(77.3)
Depreciation and amortization expense	(52.4)	(2.1)	(6.1)	—	—	(60.6)
General and administrative expense	—	—	—	(27.0)	—	(27.0)
Other income	—	—	0.4	—	—	0.4
Earnings from unconsolidated affiliates	28.6	—	—	—	—	28.6
Interest expense	—	—	—	(25.0)	—	(25.0)
Income tax expense (b)	—	—	—	(0.4)	—	(0.4)
Net income (loss)	125.6	20.9	20.6	(52.4)	—	114.7
Net income attributable to noncontrolling interests	(12.8)	—	—	—	—	(12.8)
Net income (loss) attributable to partners	$ 112.8	$ 20.9	$ 20.6	$(52.4)	$ —	$ 101.9
Non-cash derivative mark-to-market (c)	$ 48.8	$ (0.7)	$ —	$ (1.7)	$ —	$ 46.4
Capital expenditures	$ 36.7	$ 2.8	$ 6.9	$ —	$ —	$ 46.4
Acquisitions, net of cash acquired	$ 145.2	$ —	$ 29.6	$ —	$ —	$ 174.8
Investments in unconsolidated affiliates	$ 13.2	$ —	$ —	$ —	$ —	$ 13.2

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

	Nine Months Ended September 30, 2010				
	Natural Gas Services (e)	Wholesale Propane Logistics	NGL Logistics	Other	Total
			(Millions)		
Total operating revenue	$ 597.7	$ 308.9	$ 14.5	$ —	$ 921.1
Total purchases	(440.9)	(293.1)	(4.7)	—	(738.7)
Gross margin (a)	$ 156.8	$ 15.8	$ 9.8	$ —	$ 182.4
Operating and maintenance expense	(48.2)	(8.3)	(2.3)	—	(58.8)
Depreciation and amortization expense	(52.1)	(1.6)	(1.9)	(0.1)	(55.7)
General and administrative expense	—	—	—	(25.0)	(25.0)
Step acquisition — equity interest re-measurement gain	—	—	9.1	—	9.1
Other income	1.0	—	—	—	1.0
Other income — affiliates	—	3.0	—	—	3.0
Earnings from unconsolidated affiliates	28.2	—	0.8	—	29.0
Interest expense	—	—	—	(22.0)	(22.0)
Income tax expense (b)	—	—	—	(0.5)	(0.5)
Net income (loss)	85.7	8.9	15.5	(47.6)	62.5
Net income attributable to noncontrolling interests	(4.4)	—	—	—	(4.4)
Net income (loss) attributable to partners	$ 81.3	$ 8.9	$ 15.5	$ (47.6)	$ 58.1
Non-cash derivative mark-to-market (c)	$ 12.7	$ (1.1)	$ —	$ —	$ 11.6
Capital expenditures	$ 32.1	$ 0.3	$ 4.7	$ —	$ 37.1
Acquisitions, net of cash acquired	$ —	$ 66.0	$ 37.8	$ —	$ 103.8
Investments in unconsolidated affiliates	$ 27.0	$ —	$ —	$ —	$ 27.0

	September 30, 2011	December 31, 2010
	(Millions)	
Segment long-term assets:		
Natural Gas Services (e)	$ 1,270.2	$ 1,253.7
Wholesale Propane Logistics	103.1	101.7
NGL Logistics	251.9	221.7
Other (d)	16.0	4.1
Total long-term assets	1,641.2	1,581.2
Current assets	198.2	232.0
Total assets	$ 1,839.4	$ 1,813.2

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

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

(b) Income tax expense relates primarily to the Texas margin tax and the Michigan business tax.

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

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

(e) The segment information for the three and nine months ended September 30, 2010 and as of December 31, 2010 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information similar to the pooling method.

(f) Represents intersegment revenues consisting of sales of NGLs by Marysville in our NGL Logistics business to our Wholesale Propane business.

17. Supplemental Cash Flow Information

	Nine Months Ended September 30,	
	2011	2010
	(Millions)	
Cash paid for interest:		
Cash paid for interest, net of amounts capitalized	$ 7.4	$ 6.7
Cash paid for income taxes, net of income tax refunds	$29.9	$ 0.5
Non-cash investing and financing activities:		
Property, plant and equipment acquired with accounts payable	$ 7.1	$ 7.0
Other non-cash additions of property, plant and equipment	$ 1.6	$ 0.5
Accounts payable related to acquisitions	$ —	$ 1.9
Accounts payable related to equity and debt issuance costs	$ (0.2)	$ 0.5
Acquisition related contingent consideration	$ —	$ 1.0
Non-cash change in parent advances	$ 1.7	$—
Non-cash distributions to DCP Midstream, LLC	$ 2.6	$—

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

18. Supplementary Information - Condensed Consolidating Financial Information

The following condensed consolidating financial information presents the results of operations, financial position and cash flows of DCP Midstream Partners, LP, or parent guarantor, DCP Midstream Operating LP, or subsidiary issuer, which is a 100% owned subsidiary, and non-guarantor subsidiaries, as well as the consolidating adjustments necessary to present DCP Midstream Partners, LP's results on a consolidated basis. In conjunction with the universal shelf registration statement on Form S-3 filed with the SEC on May 26, 2010, the parent guarantor has agreed to fully and unconditionally guarantee securities of the subsidiary issuer. For the purpose of the following financial information, investments in subsidiaries are reflected in accordance with the equity method of accounting. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had the subsidiaries operated as independent entities.

	Condensed Consolidating Balance Sheets September 30, 2011				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ 2.1	$ 1.8	$ (1.9)	$ 2.0
Accounts receivable	—	—	127.4	—	127.4
Inventories	—	—	57.4	—	57.4
Other	—	0.8	10.6	—	11.4
Total current assets	—	2.9	197.2	(1.9)	198.2
Property, plant and equipment, net	—	—	1,137.7	—	1,137.7
Goodwill and intangible assets, net	—	—	262.3	—	262.3
Advances receivable — consolidated subsidiaries	387.9	591.6	—	(979.5)	—
Investments in consolidated subsidiaries	257.2	414.8	—	(672.0)	—
Investments in unconsolidated affiliates	—	—	222.2	—	222.2
Other long-term assets	—	1.6	17.4	—	19.0
Total assets	$ 645.1	$ 1,010.9	$ 1,836.8	$ (1,653.4)	$ 1,839.4
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$ —	$ 498.1	$ 195.8	$ (1.9)	$ 692.0
Advances payable — consolidated subsidiaries	—	—	979.5	(979.5)	—
Long-term debt	—	249.8	—	—	249.8
Other long-term liabilities	—	5.8	31.5	—	37.3
Total liabilities	—	753.7	1,206.8	(981.4)	979.1
Commitments and contingent liabilities					
Equity:					
Partners' equity					
Net equity	645.1	278.7	416.1	(672.0)	667.9
Accumulated other comprehensive loss	—	(21.5)	(1.3)	—	(22.8)
Total partners' equity	645.1	257.2	414.8	(672.0)	645.1
Noncontrolling interests	—	—	215.2	—	215.2
Total equity	645.1	257.2	630.0	(672.0)	860.3
Total liabilities and equity	$ 645.1	$ 1,010.9	$ 1,836.8	$ (1,653.4)	$ 1,839.4

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

	Condensed Consolidating Balance Sheets December 31, 2010 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ 1.5	$ 6.7	$ (1.5)	$ 6.7
Accounts receivable	—	—	151.0	—	151.0
Inventories	—	—	64.1	—	64.1
Other	—	—	10.2	—	10.2
Total current assets	—	1.5	232.0	(1.5)	232.0
Property, plant and equipment, net	—	—	1,097.1	—	1,097.1
Goodwill and intangible assets, net	—	—	258.6	—	258.6
Advances receivable — consolidated subsidiaries	333.4	534.7	—	(868.1)	—
Investments in consolidated subsidiaries	297.5	436.2	—	(733.7)	—
Investments in unconsolidated affiliates	—	—	216.9	—	216.9
Other long-term assets	—	2.3	6.3	—	8.6
Total assets	$ 630.9	$ 974.7	$ 1,810.9	$ (1,603.3)	$ 1,813.2
LIABILITIES AND EQUITY					
Accounts payable and other current liabilities	$ 0.2	$ 19.5	$ 193.0	$ (1.5)	$ 211.2
Advances payable — consolidated subsidiaries	—	—	868.1	(868.1)	—
Long-term debt	—	647.8	—	—	647.8
Other long-term liabilities	—	9.9	93.5	—	103.4
Total liabilities	0.2	677.2	1,154.6	(869.6)	962.4
Commitments and contingent liabilities					
Equity:					
Partners' equity					
Predecessor equity	—	—	112.6	—	112.6
Net equity	630.7	324.9	323.9	(733.7)	545.8
Accumulated other comprehensive loss	—	(27.4)	(0.3)	—	(27.7)
Total partners' equity	630.7	297.5	436.2	(733.7)	630.7
Noncontrolling interests	—	—	220.1	—	220.1
Total equity	630.7	297.5	656.3	(733.7)	850.8
Total liabilities and equity	$ 630.9	$ 974.7	$ 1,810.9	$ (1,603.3)	$ 1,813.2

(a) The financial information as of December 31, 2010 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information similar to the pooling method.

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

	Condensed Consolidating Statements of Operations Three Months Ended September 30, 2011				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 290.4	$ —	$ 290.4
Transportation, processing and other	—	—	40.8	—	40.8
Gains from commodity derivative activity, net	—	—	52.1	—	52.1
Total operating revenues	—	—	383.3	—	383.3
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	257.3	—	257.3
Operating and maintenance expense	—	—	31.5	—	31.5
Depreciation and amortization expense	—	—	20.6	—	20.6
General and administrative expense	—	—	9.4	—	9.4
Other income	—	—	(0.2)	—	(0.2)
Total operating costs and expenses	—	—	318.6	—	318.6
Operating income	—	—	64.7	—	64.7
Interest expense, net	—	(8.3)	(0.3)	—	(8.6)
Earnings from consolidated subsidiaries	66.3	74.6	—	(140.9)	—
Earnings from unconsolidated affiliates	—	—	10.0	—	10.0
Income before income taxes	66.3	66.3	74.4	(140.9)	66.1
Income tax expense	—	—	(0.2)	—	(0.2)
Net income	66.3	66.3	74.2	(140.9)	65.9
Net loss attributable to noncontrolling interests	—	—	0.4	—	0.4
Net income attributable to partners	$ 66.3	$ 66.3	$ 74.6	$ (140.9)	$ 66.3

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

	Condensed Consolidating Statements of Operations Three Months Ended September 30, 2010 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 227.7	$ —	$ 227.7
Transportation, processing and other	—	—	28.7	—	28.7
Losses from commodity derivative activity, net	—	—	(16.5)	—	(16.5)
Total operating revenues	—	—	239.9	—	239.9
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	200.2	—	200.2
Operating and maintenance expense	—	—	19.2	—	19.2
Depreciation and amortization expense	—	—	19.2	—	19.2
General and administrative expense	—	0.2	8.0	—	8.2
Step acquisition — equity interest re-measurement gain	—	—	(9.1)	—	(9.1)
Other income	—	—	(0.5)	—	(0.5)
Total operating costs and expenses	—	0.2	237.0	—	237.2
Operating (loss) income	—	(0.2)	2.9	—	2.7
Interest expense, net	—	(7.5)	—	—	(7.5)
Earnings from consolidated subsidiaries	—	7.7	—	(7.7)	—
Earnings from unconsolidated affiliates	—	—	8.2	—	8.2
Income before income taxes	—	—	11.1	(7.7)	3.4
Income tax expense	—	—	(0.1)	—	(0.1)
Net income	—	—	11.0	(7.7)	3.3
Net income attributable to noncontrolling interests	—	—	(3.3)	—	(3.3)
Net income attributable to partners	$ —	$ —	$ 7.7	$ (7.7)	$ —

(a) The financial information for the three months ended September 30, 2010 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information similar to the pooling method.

Table of Contents

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

	Condensed Consolidating Statements of Operations Nine Months Ended September 30, 2011				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 1,043.2	$ —	$ 1,043.2
Transportation, processing and other	—	—	114.9	—	114.9
Gains from commodity derivative activity, net	—	—	24.5	—	24.5
Total operating revenues	—	—	1,182.6	—	1,182.6
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	906.6	—	906.6
Operating and maintenance expense	—	—	77.3	—	77.3
Depreciation and amortization expense	—	—	60.6	—	60.6
General and administrative expense	—	—	27.0	—	27.0
Other income	—	—	(0.4)	—	(0.4)
Total operating costs and expenses	—	—	1,071.1	—	1,071.1
Operating income	—	—	111.5	—	111.5
Interest expense, net	—	(24.7)	(0.3)	—	(25.0)
Earnings from consolidated subsidiaries	101.9	126.6	—	(228.5)	—
Earnings from unconsolidated affiliates	—	—	28.6	—	28.6
Income before income taxes	101.9	101.9	139.8	(228.5)	115.1
Income tax expense	—	—	(0.4)	—	(0.4)
Net income	101.9	101.9	139.4	(228.5)	114.7
Net income attributable to noncontrolling interests	—	—	(12.8)	—	(12.8)
Net income attributable to partners	$ 101.9	$ 101.9	$ 126.6	$ (228.5)	$ 101.9

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

	Condensed Consolidating Statements of Operations Nine Months Ended September 30, 2010 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	(Millions)				
Operating revenues:					
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 826.1	$ —	$ 826.1
Transportation, processing and other	—	—	83.0	—	83.0
Gains from commodity derivative activity, net	—	—	12.0	—	12.0
Total operating revenues	—	—	921.1	—	921.1
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	—	—	738.7	—	738.7
Operating and maintenance expense	—	—	58.8	—	58.8
Depreciation and amortization expense	—	—	55.7	—	55.7
General and administrative expense	—	0.2	24.8	—	25.0
Step acquisition — equity interest re-measurement gain	—	—	(9.1)	—	(9.1)
Other income	—	—	(1.0)	—	(1.0)
Other income — affiliates	—	—	(3.0)	—	(3.0)
Total operating costs and expenses	—	0.2	864.9	—	865.1
Operating (loss) income	—	(0.2)	56.2	—	56.0
Interest expense, net	—	(21.9)	(0.1)	—	(22.0)
Earnings from consolidated subsidiaries	58.1	80.2	—	(138.3)	—
Earnings from unconsolidated affiliates	—	—	29.0	—	29.0
Income before income taxes	58.1	58.1	85.1	(138.3)	63.0
Income tax expense	—	—	(0.5)	—	(0.5)
Net income	58.1	58.1	84.6	(138.3)	62.5
Net income attributable to noncontrolling interests	—	—	(4.4)	—	(4.4)
Net income attributable to partners	$ 58.1	$ 58.1	$ 80.2	$ (138.3)	$ 58.1

(a) The financial information for the nine months ended September 30, 2010 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information similar to the pooling method.

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

	Condensed Consolidating Statements of Cash Flows Nine Months Ended September 30, 2011				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ (54.5)	$ (77.3)	$ 281.1	$ (0.4)	$ 148.9
INVESTING ACTIVITIES:					
Capital expenditures	—	—	(46.4)	—	(46.4)
Acquisitions, net of cash acquired	—	—	(174.8)	—	(174.8)
Investments in unconsolidated affiliates	—	—	(13.2)	—	(13.2)
Return of investment from unconsolidated affiliate	—	—	1.6	—	1.6
Proceeds from sale of assets	—	—	0.2	—	0.2
Net cash used in investing activities	—	—	(232.6)	—	(232.6)
FINANCING ACTIVITIES:					
Proceeds from debt	—	832.0	—	—	832.0
Payments of debt	—	(754.0)	—	—	(754.0)
Payment of deferred financing costs	—	(0.1)	—	—	(0.1)
Proceeds from issuance of common units, net of offering costs	152.0	—	—	—	152.0
Excess purchase price over acquired assets	—	—	(35.7)	—	(35.7)
Distributions to unitholders and general partner	(97.5)	—	—	—	(97.5)
Distributions to noncontrolling interests	—	—	(26.8)	—	(26.8)
Contributions from noncontrolling interests	—	—	9.1	—	9.1
Net cash provided by (used in) financing activities	54.5	77.9	(53.4)	—	79.0
Net change in cash and cash equivalents	—	0.6	(4.9)	(0.4)	(4.7)
Cash and cash equivalents, beginning of period	—	1.5	6.7	(1.5)	6.7
Cash and cash equivalents, end of period	$ —	$ 2.1	$ 1.8	$ (1.9)	$ 2.0

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

	Condensed Consolidating Statements of Cash Flows Nine Months Ended September 30, 2010 (a)				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
			(Millions)		
OPERATING ACTIVITIES					
Net cash (used in) provided by operating activities	$ (18.8)	$ 1.0	$ 158.3	$ (3.6)	$ 136.9
INVESTING ACTIVITIES:					
Capital expenditures	—	—	(37.1)	—	(37.1)
Acquisitions, net of cash acquired	—	—	(103.8)	—	(103.8)
Investments in unconsolidated affiliates	—	—	(27.0)	—	(27.0)
Proceeds from sale of assets	—	—	1.7	—	1.7
Return of investment from unconsolidated affiliate	—	—	1.2	—	1.2
Proceeds from sales of available-for-sale securities	—	10.1	—	—	10.1
Net cash provided by (used in) investing activities	—	10.1	(165.0)	—	(154.9)
FINANCING ACTIVITIES:					
Proceeds from debt	—	658.2	—	—	658.2
Payments of debt	—	(658.4)	—	—	(658.4)
Payment of deferred financing costs	—	(1.6)	—	—	(1.6)
Proceeds from issuance of common units, net of offering costs	93.2	—	—	—	93.2
Distributions to unitholders and general partner	(74.4)	—	—	—	(74.4)
Distributions to noncontrolling interests	—	—	(16.0)	—	(16.0)
Contributions from noncontrolling interests	—	—	10.4	—	10.4
Net change in advances to predecessor from DCP Midstream LLC	—	—	19.8	—	19.8
Purchase of additional interest in a subsidiary	—	—	(3.5)	—	(3.5)
Net cash provided by (used in) financing activities	18.8	(1.8)	10.7	—	27.7
Net change in cash and cash equivalents	—	9.3	4.0	(3.6)	9.7
Cash and cash equivalents, beginning of period	—	1.6	1.3	(0.8)	2.1
Cash and cash equivalents, end of period	$ —	$ 10.9	$ 5.3	$ (4.4)	$ 11.8

(a) The financial information for the nine months ended September 30, 2010 includes the results of Southeast Texas, a transfer of net assets between entities under common control that was accounted for as if the transfer occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information similar to the pooling method.

19. Subsequent Events

On October 26, 2011, the board of directors of the General Partner declared a quarterly distribution of $0.64 per unit, payable on November 14, 2011 to unitholders of record on November 7, 2011.

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

On November 4, 2011, we entered into agreements with DCP Midstream, LLC, to acquire the remaining 49.9% interest in East Texas for aggregate consideration of $165.0 million, subject to certain working capital and other customary purchase price adjustments. Prior to the contribution of the additional interest in East Texas, we owned a 50.1% interest which we account for as a consolidated subsidiary. The contribution of the remaining 49.9% interest in East Texas represents a transaction between entities under common control, but does not represent a change in reporting entity. Accordingly, we will include the results of the remaining 49.9% interest in East Texas prospectively from the date of acquisition. This acquisition is expected to close by the first quarter of 2012.

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

The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our condensed consolidated financial statements and notes included elsewhere in this Form 10-Q and the consolidated financial statements and notes thereto included in our 2010 Form 10-K.

Overview

We are a Delaware limited partnership formed by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. Our operations are organized into three business segments: Natural Gas Services, Wholesale Propane Logistics and NGL Logistics.

Transfers of net assets between entities under common control that represent a change in reporting entity are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our condensed consolidated financial statements have been adjusted to include the historical results of our 33.33% interest in Southeast Texas for all periods presented. We refer to our 33.33% interest in Southeast Texas, prior to our acquisition from DCP Midstream, LLC in January 2011, as our "predecessor." We recognize transfers of net assets between entities under common control at DCP Midstream, LLC's basis in the net assets contributed. The amount of the purchase price in excess of DCP Midstream, LLC's basis in the net assets is recognized as a reduction to partners' equity. The financial statements of our predecessor have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessor had been operated as an unaffiliated entity. Specifically, the terms of the joint venture agreement provide that distributions and earnings to us for the first seven years related to storage and transportation gross margin will be pursuant to a fee-based arrangement, based on storage capacity and tailgate volumes. Distributions and earnings related to the gathering and processing business, along with reductions for all expenditures, will be pursuant to our and DCP Midstream, LLC's respective ownership interests in Southeast Texas. These terms of the agreement are not reflected in the historical financial statements.

Crude oil prices have recently experienced significant volatility, but have remained at favorable levels. NGL prices have been less volatile than crude oil as a result of the favorable demand environment, and have also remained at favorable levels, while natural gas prices have remained relatively low. Natural gas drilling activity levels vary by geographic area, but in general, drilling remains robust in areas with liquids rich gas. In certain of our areas, drilling remains depressed. In addition, advances in technology, such as horizontal drilling and fractionation in shale plays, have led to certain geographic areas becoming increasingly accessible. Gas prices currently remain modest due to increased supply relative to demand. Our long-term view is that commodity prices will be at levels that we believe will support sustained or increasing levels of domestic natural gas production.

On January 1, 2011, we acquired a 33.33% interest in Southeast Texas from DCP Midstream, LLC for $150.0 million, in a transaction among entities under common control. The Southeast Texas system is a fully integrated midstream business which includes 675 miles of natural gas pipelines, three natural gas processing plants totaling 380 MMcf/d of processing capacity, natural gas storage assets with 9 Bcf of existing storage capacity, and NGL market deliveries direct to Exxon Mobil and to Mont Belvieu via our Black Lake NGL pipeline.

On March 24, 2011, we acquired two NGL fractionation facilities, or DJ Basin NGL Fractionators, for $30.0 million. The DJ Basin NGL Fractionators, which provide fee-based margins under a long-term contract, are co-located with and operated by DCP Midstream, LLC.

On August 1, 2011, we reached an agreement with DCP Midstream, LLC for us to construct a 200 MMcf/d cryogenic natural gas processing plant, or the Eagle Plant, in the Eagle Ford shale. The Eagle Plant, which represents an investment of approximately $120.0 million, will enhance DCP Midstream, LLC's existing South Texas super system comprised of 5 natural gas processing plants totaling approximately 800 MMcf/d of capacity. The Eagle Plant will be the enterprise's most efficient plant in the Eagle Ford shale. DCP Midstream, LLC will provide upstream and downstream interconnects to the plant. In support of our construction of the Eagle Plant, we entered into a 15 year fee-based processing agreement with an affiliate of DCP Midstream, LLC, which provides us with a fixed demand charge for 150 MMcf/d along with a throughput fee on all volumes processed. The processing agreement commences with commercial operations of the new plant, which is expected to be online by the fourth quarter of 2012. In conjunction with the agreement, we also entered into a purchase and sale agreement with DCP Midstream, LLC to purchase certain tangible assets and land located in the Eagle Ford Shale for $23.4 million.

On November 4, 2011, we entered into agreements with DCP Midstream, LLC, to acquire the remaining 49.9% interest in East Texas for aggregate consideration of $165.0 million, subject to certain working capital and other customary purchase price adjustments. Prior to the contribution of the additional interest in East Texas, we owned a 50.1% interest which we account for as a consolidated subsidiary. The contribution of the remaining 49.9% interest in East Texas represents a transaction between entities under common control, but does not represent a change in reporting entity. Accordingly, we will include the results of the remaining 49.9% interest in East Texas prospectively from the date of acquisition. This acquisition is expected to close by the first quarter of 2012.

Through the growth opportunities executed, we increased our business diversity, geographic and resource exposure, and our fee-based margins. Our integration efforts related to our acquisitions are progressing according to plan. The Wattenberg capital expansion project was completed during the second quarter. We raised $139.7 million in capital through a public equity offering in March used to finance a portion of our growth opportunities.

Financial results for the first three quarters of the year were in line with our previously provided 2011 forecast. We raised our distributions for the three quarters, resulting in a 4.9% increase in our quarterly distribution rate over the rate declared in the third quarter of 2010. The distributions reflect our business results as well as our recent execution on growth opportunities.

General Trends and Outlook

In 2011, our strategic objectives will continue to focus on maintaining stable distributable cash flows from our existing assets and executing on growth opportunities to increase our long-term distributable cash flows. We believe the key elements to stable distributable cash flows are the diversity of our asset portfolio, our significant fee-based business representing approximately 60% of our estimated margins, and our highly hedged commodity position, the objective of which is to protect against downside risk in our distributable cash flows.

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. In 2011, we anticipate maintenance capital expenditures of between $10.0 million and $15.0 million, and expenditures for expansion capital of between $35.0 million and $50.0 million, including $10.0 million for the expansion of storage capacity at our Southeast Texas system. We additionally plan to construct the Eagle Plant for approximately $120.0 million, with capital expenditures to be incurred by the fourth quarter of 2012 when the plant is expected to be online. The board of directors may approve additional growth capital during the year, at its discretion. This capital does not include any acquisitions or additional investment opportunities that may be identified throughout the course of the year and approved by our management and our board of directors.

Through the remainder of 2011, we expect to continue to pursue a multi-faceted growth strategy, which may include executing on organic opportunities around our footprint, third party acquisitions, and investment opportunities with or from our general partner in order to grow our distributable cash flows.

For an in-depth discussion of factors that may significantly affect our results, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Factors That May Significantly Affect Our Results” in our 2010 Form 10-K.

Reconciliation of Non-GAAP Measures

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

We define gross margin as total operating revenues, including commodity derivative activity, less purchases of natural gas, propane and NGLs, and we define segment gross margin for each segment as total operating revenues for that segment less commodity purchases for that segment. Our gross margin equals the sum of our segment gross margins. We define adjusted segment gross margin as segment gross margin plus non-cash commodity derivative losses, less non-cash commodity derivative gains for that segment. Gross margin, segment gross margin and adjusted segment gross margin are primary performance measures used by management, as these measures represent the results of product sales and purchases, a key component of our operations. As an indicator of our operating performance, gross margin, segment gross margin and adjusted segment gross margin should not be considered an alternative to, or more meaningful than, net income or loss, net income or loss attributable to partners, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with accounting principles generally accepted in the United States of America, or GAAP.

Operating and Maintenance and General and Administrative Expense — Operating and maintenance expenses are costs associated with the operation of a specific asset and are primarily comprised of direct labor, ad valorem taxes, repairs and maintenance, lease expenses, utilities and contract services. We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits, as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee under the Omnibus Agreement for centralized corporate functions performed by DCP Midstream, LLC on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, taxes and engineering. On January 1, 2011, we extended the omnibus agreement through December 31, 2011 for $10.2 million.

Adjusted EBITDA — 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
- the viability of acquisitions and capital expenditure projects and the overall rates of return on investment opportunities.

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

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or loss, net income or loss attributable to partners, 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.

Adjusted Segment EBITDA — We define adjusted segment EBITDA for each segment as segment net income or loss attributable to partners less non-cash commodity derivative gains for that segment, plus depreciation and amortization expense and non-cash commodity derivative losses for that segment, adjusted for any noncontrolling interest on depreciation and amortization expense for that segment. We use adjusted segment EBITDA, which is a financial measure not defined in GAAP. Adjusted segment EBITDA is used as a supplemental performance measure by our management and we believe by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess:

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

The accompanying schedules provide reconciliations of this non-GAAP financial measure to its most directly comparable GAAP financial measure. Adjusted segment EBITDA should not be considered in isolation or as an alternative to our financial measures presented in accordance with GAAP, including net income or loss attributable to Partners, or any other measure of performance presented in accordance with GAAP. Adjusted segment EBITDA as presented by us may not be comparable to similarly titled measures of other companies because they may not calculate adjusted segment EBITDA in the same manner.

Distributable Cash Flow — 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, net income attributable to noncontrolling interest net of depreciation and income tax, net changes in operating assets and liabilities, and other adjustments to reconcile net cash provided by or used in operating activities (see "— Liquidity and Capital Resources" 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 or earnings capacity. 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 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 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.

Our gross margin, segment gross margin, adjusted segment gross margin and adjusted segment 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. The following table sets forth our reconciliation of certain non-GAAP measures:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(Millions)			
Reconciliation of Non-GAAP Measures				
Reconciliation of net income attributable to partners to gross margin:				
Net income attributable to partners	$ 66.3	$ —	$101.9	$ 58.1
Interest expense	8.6	7.5	25.0	22.0
Income tax expense	0.2	0.1	0.4	0.5
Operating and maintenance expense	31.5	19.2	77.3	58.8
Depreciation and amortization expense	20.6	19.2	60.6	55.7
General and administrative expense	9.4	8.2	27.0	25.0
Step acquisition — equity interest re-measurement gain	—	(9.1)	—	(9.1)
Other income	(0.2)	(0.5)	(0.4)	(1.0)
Other income — affiliates	—	—	—	(3.0)
Earnings from unconsolidated affiliates	(10.0)	(8.2)	(28.6)	(29.0)
Net (loss) income attributable to noncontrolling interests	(0.4)	3.3	12.8	4.4
Gross margin	$126.0	$ 39.7	$276.0	$182.4
Non-cash commodity derivative mark-to-market (a)	$ 60.0	$(18.5)	$ 48.1	$ 11.6

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(Millions)			
Reconciliation of Non-GAAP Measures				
Reconciliation of segment net income attributable to partners to segment gross margin:				
Natural Gas Services segment:				
Segment net income attributable to partners	$ 75.4	$ 5.9	$ 112.8	$ 81.3
Operating and maintenance expense	22.8	15.0	55.0	48.2
Depreciation and amortization expense	17.5	17.3	52.4	52.1
Other income	—	(0.5)	—	(1.0)
Earnings from unconsolidated affiliates	(10.0)	(8.2)	(28.6)	(28.2)
Net (loss) income attributable to noncontrolling interests	(0.4)	3.3	12.8	4.4
Segment gross margin	$ 105.3	$ 32.8	$ 204.4	$ 156.8
Non-cash commodity derivative mark-to-market (a)	$ 59.9	$ (18.0)	$ 48.8	$ 12.7
Wholesale Propane Logistics segment:				
Segment net income (loss) attributable to partners	$ 2.1	$ (1.1)	$ 20.9	$ 8.9
Operating and maintenance expense	3.2	3.1	11.0	8.3
Depreciation and amortization expense	0.7	1.0	2.1	1.6
Other income — affiliates	—	—	—	(3.0)
Segment gross margin	$ 6.0	$ 3.0	$ 34.0	$ 15.8
Non-cash commodity derivative mark-to-market (a)	$ 0.1	$ (0.5)	$ (0.7)	$ (1.1)
NGL Logistics segment:				
Segment net income attributable to partners	$ 7.0	$ 11.1	$ 20.6	$ 15.5
Operating and maintenance expense	5.5	1.1	11.3	2.3
Depreciation and amortization expense	2.4	0.8	6.1	1.9
Other income	(0.2)	—	(0.4)	—
Step acquisition — equity interest re-measurement gain	—	(9.1)	—	(9.1)
Earnings from unconsolidated affiliates	—	—	—	(0.8)
Segment gross margin	$ 14.7	$ 3.9	$ 37.6	$ 9.8

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

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(Millions)			
Reconciliation of segment net income attributable to partners to adjusted segment EBITDA:				
Natural Gas Services segment:				
Segment net income attributable to partners	$ 75.4	$ 5.9	$ 112.8	$ 81.3
Non-cash commodity derivative mark-to-market	(59.9)	18.0	(48.8)	(12.7)
Depreciation and amortization expense	17.5	17.3	52.4	52.1
Noncontrolling interest on depreciation and income tax	(3.4)	(3.3)	(10.2)	(10.1)
Adjusted segment EBITDA	$ 29.6	$37.9	$106.2	$110.6
Wholesale Propane Logistics segment:				
Segment net income (loss) attributable to partners	$ 2.1	$ (1.1)	$ 20.9	$ 8.9
Non-cash commodity derivative mark-to-market	(0.1)	0.5	0.7	1.1
Depreciation and amortization expense	0.7	1.0	2.1	1.6
Adjusted segment EBITDA	$ 2.7	$ 0.4	$ 23.7	$ 11.6
NGL Logistics segment:				
Segment net income attributable to partners	$ 7.0	$11.1	$ 20.6	$ 15.5
Depreciation and amortization expense	2.4	0.8	6.1	1.9
Adjusted segment EBITDA	$ 9.4	$11.9	$ 26.7	$ 17.4

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are described in Item 7 in our 2010 Form 10-K. The accounting policies and estimates used in preparing our interim condensed consolidated financial statements for the three and nine months ended September 30, 2011 are the same as those described in our 2010 Form 10-K, as updated by recent accounting pronouncements that we have adopted in Note 2 of the Notes to Condensed Consolidated Financial Statements in Item 1. "Financial Statements".

[Table of Contents](#)

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three and nine months ended September 30, 2011 and 2010. The results of operations by segment are discussed in further detail following this consolidated overview discussion:

	Three Months Ended September 30,		Nine Months Ended September 30,		Variance Three Months 2011 vs. 2010		Variance Nine Months 2011 vs. 2010	
	2011 (b)(c)(d)	2010 (a)(b)(c)(d)	2011 (b)(c)(d)	2010 (a)(b)(c)(d)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues (h):								
Natural Gas Services (e)	$ 268.5	$ 167.9	$ 690.4	$ 597.7	$ 100.6	60%	$ 92.7	16%
Wholesale Propane Logistics	100.1	65.9	452.1	308.9	34.2	52%	143.2	46%
NGL Logistics	14.7	6.1	42.3	14.5	8.6	141%	27.8	192%
Intra-segment Eliminations	—	—	(2.2)	—	—	— %	(2.2)	*%
Total operating revenues	383.3	239.9	1,182.6	921.1	143.4	60%	261.5	28%
Gross margin (f):								
Natural Gas Services	105.3	32.8	204.4	156.8	72.5	221%	47.6	30%
Wholesale Propane Logistics	6.0	3.0	34.0	15.8	3.0	100%	18.2	115%
NGL Logistics	14.7	3.9	37.6	9.8	10.8	277%	27.8	284%
Total gross margin	126.0	39.7	276.0	182.4	86.3	217%	93.6	51%
Operating and maintenance expense	(31.5)	(19.2)	(77.3)	(58.8)	12.3	64%	18.5	31%
Depreciation and amortization expense	(20.6)	(19.2)	(60.6)	(55.7)	1.4	7%	4.9	9%
General and administrative expense	(9.4)	(8.2)	(27.0)	(25.0)	1.2	15%	2.0	8%
Step acquisition — equity interest re-measurement gain	—	9.1	—	9.1	(9.1)	(100)%	(9.1)	(100)%
Other income	0.2	0.5	0.4	1.0	(0.3)	(60)%	(0.6)	(60)%
Other income — affiliates	—	—	—	3.0	—	— %	(3.0)	(100)%
Earnings from unconsolidated affiliates (g)	10.0	8.2	28.6	29.0	1.8	22%	(0.4)	(1)%
Interest expense	(8.6)	(7.5)	(25.0)	(22.0)	1.1	15%	3.0	14%
Income tax expense	(0.2)	(0.1)	(0.4)	(0.5)	0.1	100%	(0.1)	(20)%
Net loss (income) attributable to noncontrolling interests	0.4	(3.3)	(12.8)	(4.4)	(3.7)	*%	8.4	191%
Net income attributable to partners	$ 66.3	$ —	$ 101.9	$ 58.1	$ 66.3	100%	$ 43.8	75%
Other data:								
Non-cash commodity derivative mark-to-market	$ 60.0	$ (18.5)	$ 48.1	$ 11.6	$ 78.5	*%	$ 36.5	315%
Natural gas throughput (MMcf/d) (g)	1,164	1,276	1,220	1,264	(112)	(9)%	(44)	(3)%
NGL gross production (Bbls/d) (g)	37,676	40,664	39,701	40,319	(2,988)	(7)%	(618)	(2)%
Propane sales volume (Bbls/d)	15,257	14,086	23,944	20,165	1,171	8%	3,779	19%
NGL pipelines throughput (Bbls/d) (g)	68,564	41,392	57,802	39,004	27,172	66%	18,798	48%

* Percentage change is not meaningful.

(a) On January 1, 2011, we acquired a 33.33% interest in Southeast Texas for $150.0 million, in a transaction among entities under common control. This transfer of net assets between entities under common control was accounted for as if the transfer occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our condensed consolidated financial statements have been adjusted to include the historical results of our 33.33% interest in Southeast Texas for the three and nine months ended September 30, 2010.

(b) Includes the results of Atlantic Energy, since July 30, 2010, the date of acquisition, in our Wholesale Propane Logistics segment.

(c) Includes the results of our Wattenberg pipeline, Black Lake pipeline, Marysville NGL storage facility and DJ Basin NGL Fractionators since the dates of acquisition of January 28, 2010, July 30, 2010, December 30, 2010 and March 24, 2011, respectively, in our NGL Logistics Segment.

(d) We utilize commodity derivative instruments to provide stability to distributable cash flows for our proportionate 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 49.9% of East Texas unhedged.

(e) Included in Natural Gas Services revenue is 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, which commenced in April 2009 and expired in March 2010.

(f) 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 “Reconciliation of Non-GAAP Measures” above.

(g) Includes our proportionate share of the throughput volumes and NGL production of Collbran, Jackson Pipeline Company, or Jackson, Southeast Texas, East Texas, and Discovery and our proportionate earnings of Discovery. Earnings for Discovery include the accretion of the net difference between the carrying amount of the investment and the underlying equity of the investment.
For periods prior to July 30, 2010, includes our 50% share of the throughput volumes and earnings for Black Lake. Black Lake’s earnings included the accretion of the net difference between the carrying amount of the investment and the underlying equity of the investment.

(h) Operating revenues include the impact of commodity derivative activity.

Three Months Ended September 30, 2011 vs. Three Months Ended September 30, 2010

Included in the consolidated results of operations are the noncontrolling interests which represent the third party or affiliate interests in the non-wholly-owned entities that we consolidate, which include East Texas and Collbran, among others. Our results of operations reflect 100% of all consolidated assets, including noncontrolling interests.

Total Operating Revenues — Total operating revenues increased in 2011 compared to 2010 primarily as a result of the following:

- $68.6 million increase related to commodity derivative activity. This includes an increase of $78.6 million in unrealized gains due to movements in forward prices of commodities, offset by an increase in cash settlement losses of $10.0 million;
- $33.4 million increase primarily attributable to higher propane prices for our Wholesale Propane Logistics segment and our acquisition of Atlantic Energy;
- $31.2 million increase primarily attributable to higher crude and NGL prices, partially offset by reduced volumes on our Pelico system; and

- $10.2 million increase in transportation, processing and other revenue, which represents our fee-based revenues, primarily as a result of our acquisitions of the Marysville NGL storage facility, the DJ Basin NGL Fractionators, an additional 50% interest in Black Lake and the Wattenberg capital expansion project.

Gross Margin — Gross margin increased in 2011 compared to 2010, primarily as a result of the following:

- $72.5 million increase for our Natural Gas Services segment, primarily related to commodity derivative activities, higher crude oil and NGL prices, partially offset by planned turnaround activity at East Texas and an extended planned third party outage at our Wyoming asset;
- $10.8 million increase for our NGL Logistics segment primarily as a result of acquisitions of the Marysville NGL storage facility, the DJ Basin NGL Fractionators and an additional 50% interest in Black Lake, increased throughput on our pipelines, and the Wattenberg capital expansion project; and
- $3.0 million increase for our Wholesale Propane Logistics segment primarily as a result of higher unit margins and increased volumes. 2010 results reflect a planned outage related to our Providence terminal inspection.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2011 compared to 2010, primarily as a result of planned turnaround activity and environmental remediation at East Texas, our acquisitions of the Marysville NGL storage facility, an additional 50% interest in Black Lake and the DJ Basin NGL Fractionators, and the Wattenberg capital expansion project. 2011 results were impacted by the timing of expenditures related to turnaround activity and the transition and integration of our acquisition of Marysville and pipeline integrity testing.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, the DJ Basin NGL Fractionators, an additional 50% interest in Black Lake and the Wattenberg capital expansion project.

Step acquisition — equity interest re-measurement gain — The non-cash step acquisition — equity interest re-measurement gain in 2010 resulted from our acquisition of an additional 50% interest in Black Lake bringing our ownership interest in Black Lake to 100% in our NGL Logistics segment. Prior to our acquisition of an additional 50% interest in Black Lake, we accounted for Black Lake under the equity method of accounting. Subsequent to this transaction we account for Black Lake as a consolidated subsidiary. As a result of acquiring an additional 50% interest in Black Lake, we remeasured our initial 50% equity interest in Black Lake to its fair value, and recognized a non-cash gain of $9.1 million.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates, representing our 40% ownership of Discovery and 33.33% ownership of Southeast Texas, increased in 2011 compared to 2010, as a result of increased earnings at Discovery, partially offset by planned turnaround activity at our Southeast Texas asset. Commodity derivative activity related to our unconsolidated affiliates is included in segment gross margin.

Net loss (income) attributable to noncontrolling interests — Net income attributable to noncontrolling interests decreased in 2011 compared to 2010 due to planned turnaround activity and environmental remediation at East Texas, as well as the timing of expenditures.

Nine Months Ended September 30, 2011 vs. Nine Months Ended September 30, 2010

Included in the consolidated results of operations are the noncontrolling interests which represent the third party or affiliate interests in the non-wholly-owned entities that we consolidate, which include East Texas and Collbran, among others. Our results of operations reflect 100% of all consolidated assets, including noncontrolling interests.

Total Operating Revenues — Total operating revenues increased in 2011 compared to 2010 primarily as a result of the following:

- $143.9 million increase primarily as a result of our acquisition of Atlantic Energy, as well as higher propane prices for our Wholesale Propane Logistics segment;
- $75.0 million increase primarily attributable to higher crude and NGL prices and the East Texas recovery settlement, partially offset by reduced volumes on our Pelico system;

- $30.1 million increase in transportation, processing and other revenue, which represents our fee-based revenues, primarily as a result of our acquisitions of the Marysville NGL storage facility, the DJ Basin NGL Fractionators, the additional 50% interest in Black Lake, and the Wattenberg capital expansion project; and
- $12.5 million increase related to commodity derivative activity. This includes an increase of $36.4 million in unrealized gains due to movements in forward prices of commodities, offset by an increase in cash settlement losses of $23.9 million.

Gross Margin — Gross margin increased in 2011 compared to 2010, primarily as a result of the following:

- $47.6 million increase for our Natural Gas Services segment primarily as a result of higher crude oil and NGL prices, commodity derivative activities, the East Texas recovery settlement, and increased volumes and NGL production across certain assets, partially offset by planned turnaround activity at East Texas and an extended planned third party outage at our Wyoming asset;
- $27.8 million increase for our NGL Logistics segment primarily as a result of our acquisitions of the Marysville NGL storage facility, an additional 50% interest in Black Lake, the DJ Basin NGL Fractionators and the Wattenberg capital expansion project. The 2010 results include a market opportunity at Seabreeze; and
- $18.2 million increase for our Wholesale Propane Logistics segment primarily as a result of our acquisition of Atlantic Energy, higher unit margins and increased volumes. 2010 results reflect a planned outage related to our Providence terminal inspection and reduced demand as a result of an early spring and warmer weather.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, Atlantic Energy and an additional 50% interest in Black Lake, the Wattenberg capital expansion project, our acquisition of the DJ Basin NGL Fractionators, and planned turnaround activity and environmental remediation at East Texas.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, an additional 50% interest in Black Lake, the DJ Basin NGL Fractionators, Atlantic Energy, and the Wattenberg capital expansion project.

Step acquisition — equity interest re-measurement gain — The non-cash step acquisition — equity interest re-measurement gain in 2010 resulted from our acquisition of an additional 50% interest in Black Lake bringing our ownership interest in Black Lake to 100% in our NGL Logistics segment. Prior to our acquisition of an additional 50% interest in Black Lake, we accounted for Black Lake under the equity method of accounting. Subsequent to this transaction we account for Black Lake as a consolidated subsidiary. As a result of acquiring an additional 50% interest in Black Lake, we remeasured our initial 50% equity interest in Black Lake to its fair value, and recognized a non-cash gain of $9.1 million.

Other income — affiliates — Other income — affiliates results for 2010 reflect a $3.0 million payment received in the second quarter from Spectra Energy, a supplier for our Wholesale Propane Logistics segment, related to an amendment of a supply agreement to shorten the term of the agreement by two years.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates decreased in 2011 compared to 2010 primarily due to our additional interest in Black Lake. Prior to our acquisition of an additional 50% interest in Black Lake, we accounted for Black Lake under the equity method of accounting. Subsequent to this transaction, we account for Black Lake as a consolidated subsidiary. Commodity derivative activity related to our unconsolidated affiliates is included in segment gross margin.

Net loss (income) attributable to noncontrolling interests — Net income attributable to noncontrolling interests increased in 2011 compared to 2010 as a result of the East Texas recovery settlement.

Results of Operations — Natural Gas Services Segment

This segment consists of our Northern Louisiana system, our Southern Oklahoma system, our Wyoming system, our Michigan system, our 33.33% interest in the Southeast Texas system, our 50.1% interest in the East Texas system, our 75% interest in the Colorado system, and our 40% limited liability company interest in Discovery:

	Three Months Ended September 30,		Nine Months Ended September 30,		Variance Three Months 2011 vs. 2010		Variance Nine Months 2011 vs. 2010	
	2011 (a)	2010 (a)(b)	2011 (a)	2010 (a)(b)(c)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of natural gas, NGLs and condensate	$ 190.3	$ 159.2	$ 587.1	$ 512.0	$ 31.1	20%	$ 75.1	15%
Transportation, processing and other	26.2	24.4	77.4	72.9	1.8	7%	4.5	6%
Gains (losses) from commodity derivative activity	52.0	(15.7)	25.9	12.8	67.7	*%	13.1	102%
Total operating revenues	268.5	167.9	690.4	597.7	100.6	60%	92.7	16%
Purchases of natural gas and NGLs	163.2	135.1	486.0	440.9	28.1	21%	45.1	10%
Segment gross margin (d)	105.3	32.8	204.4	156.8	72.5	221%	47.6	30%
Operating and maintenance expense	(22.8)	(15.0)	(55.0)	(48.2)	7.8	52%	6.8	14%
Depreciation and amortization expense	(17.5)	(17.3)	(52.4)	(52.1)	0.2	1%	0.3	1%
Other income	—	0.5	—	1.0	(0.5)	(100)%	(1.0)	(100)%
Earnings from unconsolidated affiliates (e)	10.0	8.2	28.6	28.2	1.8	22%	0.4	1%
Segment net income	75.0	9.2	125.6	85.7	65.8	715%	39.9	47%
Segment net loss (income) attributable to noncontrolling interests	0.4	(3.3)	(12.8)	(4.4)	(3.7)	*%	8.4	191%
Segment net income attributable to partners	$ 75.4	$ 5.9	$ 112.8	$ 81.3	$ 69.5	1,178%	$ 31.5	39%
Other data:								
Non-cash commodity derivative mark-to-market	$ 59.9	$ (18.0)	$ 48.8	$ 12.7	$ 77.9	*%	$ 36.1	284%
Natural gas throughput (MMcf/d) (e)	1,164	1,276	1,220	1,264	(112)	(9)%	(44)	(3)%
NGL gross production (Bbls/d) (e)	37,676	40,664	39,701	40,319	(2,988)	(7)%	(618)	(2)%

* Percentage change is not meaningful.

(a) We utilize commodity derivative instruments to provide stability to 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 49.9% of East Texas unhedged.

(b) On January 1, 2011, we acquired a 33.33% interest in Southeast Texas for $150.0 million, in a transaction among entities under common control. This transfer of net assets between entities under common control was accounted for as if the transfer occurred at the beginning of the period, and prior years were retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our condensed consolidated financial statements have been adjusted to include the historical results of Southeast Texas for the three and nine months ended September 30, 2010.

(c) Includes the effect of the acquisition of the NGL Hedge, contributed by DCP Midstream, LLC in April 2009 in gains (losses) from commodity derivative activity. The NGL Hedge is a fixed price natural gas liquids derivative by NGL component, which commenced in April 2009 and expired in March 2010.

(d) Segment gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas and NGLs. Please read “Reconciliation of Non-GAAP Measures” above.

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

Three Months Ended September 30, 2011 vs. Three Months Ended September 30, 2010

Included in the consolidated results of operations are the noncontrolling interests which represent the third party or affiliate interests in the non-wholly-owned entities that we consolidate, which include East Texas and Collbran, among others. Our results of operations reflect 100% of all consolidated assets, including noncontrolling interests.

Total Operating Revenues — Total operating revenues increased in 2011 compared to 2010, primarily as a result of the following:

- $67.7 million increase related to commodity derivative activity. This includes an increase of $78.0 million in unrealized gains due to movements in forward prices of commodities, offset by an increase in cash settlement losses of $10.3 million; and
- $40.8 million increase attributable to higher crude and NGL prices, which impact both sales and purchases.

These increases were partially offset by:

- $7.9 million decrease attributable to reduced volumes on our Pelico system, partially offset by an increase in transportation, processing and other revenue.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs increased in 2011 compared to 2010, primarily as a result of increases in commodity prices, which impact both purchases and sales.

Segment Gross Margin — Segment gross margin increased in 2011 compared to 2010, primarily as a result of the following:

- $67.7 million increase related to commodity derivative activity as discussed in the Operating Revenues section above; and
- $8.3 million increase as a result of higher crude and NGL prices.

These increases were partially offset by:

- $3.5 million decrease attributable to planned turnaround activity at East Texas and an extended planned third party outage at our Wyoming asset.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2011 compared to 2010 due to planned turnaround activity and environmental remediation at East Texas as well as the timing of expenditures.

Depreciation and Amortization Expense — Depreciation and amortization expense remained relatively constant in 2011 compared to 2010.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates, representing our 40% ownership of Discovery and 33.33% ownership of Southeast Texas, increased in 2011 compared to 2010, as a result of increased earnings at Discovery, partially offset by planned turnaround activity at our Southeast Texas asset. 2010 results reflect a different business structure and cash flow profile at Southeast Texas. Commodity derivative activity related to our unconsolidated affiliates is included in segment gross margin.

Segment net loss (income) attributable to noncontrolling interests — Segment net income attributable to noncontrolling interests decreased in 2011 compared to 2010 due to planned turnaround activity and environmental remediation at East Texas, as well as the timing of expenditures.

Natural Gas Throughput — Natural gas transported, processed and/or treated decreased in 2011 compared to 2010 primarily as a result of reduced volumes on our Pelico system, planned turnaround activity at our East Texas and Southeast Texas assets, and an extended planned third party outage at our Wyoming asset.

NGL Gross Production — NGL production decreased in 2011 compared to 2010 primarily attributable to planned turnaround activity at our East Texas and Southeast Texas assets, changes in contract mix and an extended planned third party outage at our Wyoming asset.

Nine Months Ended September 30, 2011 vs. Nine Months Ended September 30, 2010

Included in the consolidated results of operations are the noncontrolling interests which represent the third party or affiliate interests in the non-wholly-owned entities that we consolidate, which include East Texas and Collbran, among others. Our results of operations reflect 100% of all consolidated assets, including noncontrolling interests.

Total Operating Revenues — Total operating revenues increased in 2011 compared to 2010, primarily as a result of the following:

- $88.2 million increase attributable to higher crude and NGL prices, which impact both sales and purchases;
- $13.1 million increase related to commodity derivative activity. This includes an increase of $36.0 million in unrealized gains due to movements in forward prices of commodities, offset by an increase in cash settlement losses of $22.9 million; and
- $6.6 million increase attributable to the East Texas recovery settlement.

These increases were partially offset by:

- $15.2 million decrease attributable to reduced volumes on our Pelico system, partially offset by increased volumes across certain assets and an increase in transportation, processing and other revenue.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs increased in 2011 compared to 2010, primarily as a result of increases in commodity prices, which impact both purchases and sales.

Segment Gross Margin — Segment gross margin increased in 2011 compared to 2010, primarily as a result of the following:

- $21.5 million increase as a result of higher crude oil and NGL prices;
- $13.1 million increase related to commodity derivative activity as discussed in the Operating Revenues section above;
- $6.6 million increase attributable to the East Texas recovery settlement; and
- $6.4 million increase primarily attributable to increased volumes and NGL production across certain assets and changes in contract terms, partially offset by planned turnaround activity at East Texas and an extended planned third party outage at our Wyoming asset.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2011 compared to 2010 due to planned turnaround activity and environmental remediation at East Texas.

Depreciation and Amortization Expense — Depreciation and amortization expense remained relatively constant in 2011 compared to 2010.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates, representing our 40% ownership of Discovery and 33.33% ownership of Southeast Texas, remained relatively constant in 2011 compared to 2010. 2010 results reflect business interruption insurance recoveries and a different business structure and cash flow profile at Southeast Texas. Commodity derivative activity related to our unconsolidated affiliates is included in segment gross margin.

Segment net loss (income) attributable to noncontrolling interests — Segment net income attributable to noncontrolling interests increased in 2011 compared to 2010, with $4.6 million due to the East Texas recovery settlement.

Natural Gas Throughput — Natural gas transported, processed and/or treated decreased in 2011 compared to 2010 primarily as a result of reduced volumes on our Pelico system.

NGL Gross Production — NGL production remained relatively stable in 2011 compared to 2010.

Table of Contents

Results of Operations — Wholesale Propane Logistics Segment

This segment consists of our propane terminals, which include six owned and operated rail terminals, one owned marine import terminal, one leased marine terminal, one pipeline terminal and access to several open-access propane pipeline terminals:

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010 (a)	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010 (a)	Variance Three Months 2011 vs. 2010 Increase (Decrease)	Variance Three Months 2011 vs. 2010 Percent	Variance Nine Months 2011 vs. 2010 Increase (Decrease)	Variance Nine Months 2011 vs. 2010 Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of propane	$ 100.1	$ 66.7	$ 453.4	$ 309.5	$ 33.4	50%	$ 143.9	46 %
Other	(0.1)	—	0.1	0.2	(0.1)	(100)%	(0.1)	(50)%
Gains (losses) from commodity derivative activity	0.1	(0.8)	(1.4)	(0.8)	0.9	*%	(0.6)	(75)%
Total operating revenues	100.1	65.9	452.1	308.9	34.2	52%	143.2	46%
Purchases of propane	94.1	62.9	418.1	293.1	31.2	50%	125.0	43%
Segment gross margin (b)	6.0	3.0	34.0	15.8	3.0	100%	18.2	115%
Operating and maintenance expense	(3.2)	(3.1)	(11.0)	(8.3)	0.1	3%	2.7	33%
Depreciation and amortization expense	(0.7)	(1.0)	(2.1)	(1.6)	(0.3)	(30)%	0.5	31%
Other income — affiliates	—	—	—	3.0	—	— %	(3.0)	(100)%
Segment net income (loss) attributable to partners	$ 2.1	$ (1.1)	$ 20.9	$ 8.9	$ 3.2	*%	$ 12.0	135%
Other data:								
Non-cash commodity derivative mark-to-market	$ 0.1	$ (0.5)	$ (0.7)	$ (1.1)	$ 0.6	*%	$ 0.4	36%
Propane sales volume (Bbls/d)	15,257	14,086	23,944	20,165	1,171	8%	3,779	19%

* Percentage change is not meaningful.

(a) Includes the results of our Chesapeake terminal, acquired July 30, 2010 from Atlantic Energy.

(b) Segment gross margin consists of total operating revenues, including commodity derivative activity, less purchases of propane. Please read “Reconciliation of Non-GAAP Measures” above.

Three Months Ended September 30, 2011 vs. Three Months Ended September 30, 2010

Total Operating Revenues — Total operating revenues increased in 2011 compared to 2010, primarily as a result of the following

- $28.5 million increase attributable to higher propane prices, which impacts both purchases and sales;
- $4.8 million increase primarily attributable to our acquisition of Atlantic Energy; and
- $0.9 million increase related to commodity derivative activity.

Purchases of Propane — Purchases of propane increased in 2011 compared to 2010 due to higher propane prices, which impact both sales and purchases, and our acquisition of Atlantic Energy.

Segment Gross Margin — Segment gross margin increased in 2011 compared to 2010, primarily as a result of higher unit margins and increased volumes. 2010 results reflect a planned outage related to our Providence terminal inspection.

Operating and Maintenance Expense — Operating and maintenance expense remained relatively constant in 2011 compared to 2010.

Propane Sales Volume —Propane sales volumes increased in 2011 compared to 2010. 2010 results reflect a planned outage related to our Providence terminal inspection.

Nine Months Ended September 30, 2011 vs. Nine Months Ended September 30, 2010

Total Operating Revenues — Total operating revenues increased in 2011 compared to 2010, primarily as a result of the following:

- $79.8 million increase attributable to higher propane prices, which impacts both purchases and sales; and
- $64.0 million increase primarily as a result of our acquisition of Atlantic Energy.

These increases were partially offset by:

- $0.6 million decrease related to commodity derivative activity.

Purchases of Propane — Purchases of propane increased in 2011 compared to 2010 due to higher propane prices, which impact both sales and purchases, and our acquisition of Atlantic Energy.

Segment Gross Margin — Segment gross margin increased in 2011 compared to 2010, primarily as a result of our acquisition of Atlantic Energy, higher unit margins and increased volumes. 2010 results reflect a planned outage related to our Providence terminal inspection and reduced demand as a result of an early spring and warmer weather.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2011 compared to 2010, primarily as a result of our acquisition of Atlantic Energy.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2011 compared to 2010, primarily as a result of our acquisition of Atlantic Energy.

Other income — affiliates — Other income — affiliates results for 2010 reflect a $3.0 million payment received in the second quarter from Spectra Energy, a supplier for our Wholesale Propane Logistics segment, related to an amendment of a supply agreement to shorten the term of the agreement by two years.

Propane Sales Volume — Propane sales volumes increased in 2011 compared to 2010, primarily as a result of our acquisition of Atlantic Energy. 2010 results reflect a planned outage related to our Providence terminal inspection and reduced demand as a result of an early spring and warmer weather.

Results of Operations — NGL Logistics Segment

The segment consists of the Seabreeze and Wilbreeze intrastate NGL pipelines, the Wattenberg and Black Lake interstate NGL pipelines, the NGL storage facility in Michigan and the DJ Basin NGL Fractionators in Colorado:

	Three Months Ended September 30,		Nine Months Ended September 30,		Variance Three Months 2011 vs. 2010		Variance Nine Months 2011 vs. 2010	
	2011 (d)	2010 (b)	2011 (d)	2010 (b)(c)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except as indicated)							
Operating revenues:								
Sales of NGLs	$ —	$ 1.8	$ 4.9	$ 4.6	$ (1.8)	*%	$ 0.3	7%
Transportation, processing and other	14.7	4.3	37.4	9.9	10.4	242%	27.5	278%
Total operating revenues	14.7	6.1	42.3	14.5	8.6	141%	27.8	192%
Purchases of NGLs	—	2.2	4.7	4.7	(2.2)	(100)%	—	— %
Segment gross margin (a)	14.7	3.9	37.6	9.8	10.8	277%	27.8	284%
Operating and maintenance expense	(5.5)	(1.1)	(11.3)	(2.3)	4.4	400%	9.0	391%
Depreciation and amortization expense	(2.4)	(0.8)	(6.1)	(1.9)	1.6	200%	4.2	221%
Step acquisition — equity interest re-measurement gain	—	9.1	—	9.1	(9.1)	(100)%	(9.1)	(100)%
Other income	0.2	—	0.4	—	0.2	100%	0.4	100%
Earnings from unconsolidated affiliates (c)	—	—	—	0.8	—	— %	(0.8)	(100)%
Segment net income attributable to partners	$ 7.0	$ 11.1	$ 20.6	$ 15.5	$ (4.1)	(37)%	$ 5.1	33%
Other data:								
NGL pipelines throughput (Bbls/d) (c)	68,564	41,392	57,802	39,004	27,172	66%	18,798	48%

* Percentage change is not meaningful.

(a) Segment gross margin consists of total operating revenues less purchases of NGLs. Please read “Reconciliation of Non-GAAP Measures” above.

(b) Includes the results of our Wattenberg pipeline and our Black Lake pipeline since the dates of acquisition of January 28, 2010 and July 30, 2010, respectively.

(c) For periods prior to July 30, 2010, includes our 50% share of the throughput volumes and earnings for Black Lake. Black Lake’s earnings included the accretion of the net difference between the carrying amount of the investment and the underlying equity of the investment.

(d) Includes the results of our Marysville NGL storage facility and our DJ Basin NGL Fractionators since the dates of acquisition of December 30, 2010 and March 24, 2011, respectively.

Three Months Ended September 30, 2011 vs. Three Months Ended September 30, 2010

Total Operating Revenues — Total operating revenues increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, the DJ Basin NGL Fractionators, an additional 50% interest in Black Lake and the Wattenberg capital expansion project.

Segment Gross Margin — Segment gross margin increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, the DJ Basin NGL Fractionators and an additional 50% interest in Black Lake, increased throughput on our pipelines, and the Wattenberg capital expansion project.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, an additional 50% interest in Black Lake and the DJ Basin NGL Fractionators, and the Wattenberg capital expansion project. 2011 results were impacted by the timing of expenditures related to the transition and integration of our Marysville acquisition and pipeline integrity testing.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, the DJ Basin NGL Fractionators, an additional 50% interest in Black Lake and the Wattenberg capital expansion project.

Step acquisition — equity interest re-measurement gain — The non-cash step acquisition — equity interest re-measurement gain in 2010 resulted from our acquisition of an additional 50% interest in Black Lake bringing our ownership interest in Black Lake to 100%. Prior to our acquisition of an additional 50% interest in Black Lake, we accounted for Black Lake under the equity method of accounting. Subsequent to this transaction we account for Black Lake as a consolidated subsidiary. As a result of acquiring an additional 50% interest in Black Lake, we remeasured our initial 50% equity interest in Black Lake to its fair value, and recognized a non-cash gain of $9.1 million.

NGL Pipelines Throughput — NGL pipelines throughput increased in 2011 compared to 2010 as a result of the Wattenberg capital expansion project, volume growth on our pipelines and our acquisition of an additional 50% interest in Black Lake,.

Nine Months Ended September 30, 2011 vs. Nine Months Ended September 30, 2010

Total Operating Revenues — Total operating revenues increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, an additional 50% interest in Black Lake, the DJ Basin NGL Fractionators and the Wattenberg capital expansion project. The 2010 results include a market opportunity at Seabreeze.

Segment Gross Margin — Segment gross margin increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, an additional 50% interest in Black Lake, the DJ Basin NGL Fractionators and the Wattenberg capital expansion project. The 2010 results include a market opportunity at Seabreeze.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, an additional 50% interest in Black Lake, the DJ Basin NGL Fractionators, and the Wattenberg capital expansion project.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2011 compared to 2010, primarily as a result of our acquisitions of the Marysville NGL storage facility, an additional 50% interest in Black Lake, the DJ Basin NGL Fractionators, and the Wattenberg capital expansion project.

Step acquisition — equity interest re-measurement gain — The non-cash step acquisition — equity interest re-measurement gain in 2010 resulted from our acquisition of an additional 50% interest in Black Lake bringing our ownership interest in Black Lake to 100%. Prior to our acquisition of an additional 50% interest in Black Lake, we accounted for Black Lake under the equity method of accounting. Subsequent to this transaction we account for Black Lake as a consolidated subsidiary. As a result of acquiring an additional 50% interest in Black Lake, we remeasured our initial 50% equity interest in Black Lake to its fair value, and recognized a non-cash gain of $9.1 million.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates decreased in 2011 compared to 2010 reflecting the impact of our additional interest in Black Lake. Prior to our acquisition of an additional 50% interest in Black Lake, we accounted for Black Lake under the equity method of accounting. Subsequent to this transaction, we account for Black Lake as a consolidated subsidiary.

NGL Pipelines Throughput — NGL pipelines throughput increased in 2011 compared to 2010 as a result of our acquisition an additional 50% interest in Black Lake, the Wattenberg capital expansion project and volume growth on our pipelines. The 2010 results include a market opportunity at Seabreeze.

Liquidity and Capital Resources

We expect our sources of liquidity to include:

- cash generated from operations;
- cash distributions from our unconsolidated affiliates;
- borrowings under our revolving credit 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 unconsolidated affiliates to finance our share of their capital expenditures;
- business and asset acquisitions; and
- 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.

We routinely evaluate opportunities for strategic investments or acquisitions. Future material investments or acquisitions may require that we obtain additional capital, assume third party debt or incur other long-term obligations. We have the option to utilize both equity and debt instruments as vehicles for the long-term financing of our investment activities and acquisitions.

On August 17, 2011, we entered into an equity distribution agreement with Citigroup Global Markets Inc., or Citi. The agreement provides for the offer and sale from time to time through Citi, our sales agent, common units having an aggregate offering amount of up to $150 million. During the three months ended September 30, 2011, we issued 345,031 of our common units pursuant to this equity distribution agreement. We received proceeds of $12.5 million from the issuance of these common units, net of commissions and offering costs of $0.5 million, which were used to finance growth opportunities.

In March 2011, we executed a public equity offering which generated net proceeds of $139.7 million. The proceeds from the equity issuance were used primarily to fund our growth strategy, including acquisitions and organic expansion. The 2011 acquisitions include our purchase of a 33.33% interest in Southeast Texas for total cash consideration of $150.0 million and the DJ Basin NGL Fractionators for total cash consideration of $30.0 million. Our portion of expansion capital expenditures for the three and nine months ended September 30, 2011 was $11.8 million and $30.2 million, respectively.

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 could limit our borrowing capacity, raise our financing costs, as well as impact our compliance with our financial covenant requirements under our Credit Agreement. Our sources of funding could include additional borrowings under our Credit Agreement, the placement of public and private debt, and the issuance of our common units.

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 portion of our anticipated commodity price risk associated with the equity volumes from our gathering and processing activities through 2016 with fixed price commodity swaps and collar arrangements. For additional information regarding our derivative activities, please read “Item7A. Quantitative and Qualitative Disclosures about Market Risk” in our 2010 Form 10-K and “Item 3. Quantitative and Qualitative Disclosures about Market Risk” in this Quarterly Report on Form 10-Q.

Our Credit Agreement consists of a revolving credit facility with capacity of $850.0 million, which matures on June 21, 2012. As of September 30, 2011, the outstanding balance on the revolving credit facility was $476.0 million resulting in unused revolver capacity of $372.9 million, of which approximately $346.0 million was available for general working capital purposes.

We are actively executing on a plan to refinance our credit facility and are currently in negotiations with a group of banks, including lenders to our existing credit facility, regarding a proposed five-year $1.0 billion revolving credit facility (the proposed credit facility). We anticipate the proposed credit facility would be priced at current market rates and contain covenants and other terms that are similar to those in our existing credit agreement. There can be no assurance that we will be able to finalize the proposed credit facility and have the loans contemplated by the proposed credit facility available to us.

Our borrowing capacity is currently 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 November 3, 2011, we had approximately $360.9 million of unused capacity under the Credit Agreement.

On September 30, 2010, we issued $250.0 million of 3.25% Senior Notes due October 1, 2015. We received net proceeds, after deducting underwriting discounts and offering expenses, of $247.7 million, which we used to repay funds borrowed under the revolver portion of our Credit Facility.

In March 2011, we issued 3,596,636 common limited partner units at $40.55 per unit. We received proceeds of $139.7 million, net of offering costs.

In September 2011, we issued 4,000 common limited partner units, from our long-term incentive plan, or LTIP, to non-employee directors as compensation for their service during 2011.

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 November 3, 2011, DCP Midstream, LLC had issued and outstanding parental guarantees totaling $70.0 million in favor of 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 0.50% per annum on these guarantees. As of November 3, 2011, we had a contingent letter of credit facility for up to $10.0 million, on which we pay a fee of 0.50% per annum. As of November 3, 2011, we had no letters of credit issued on this facility; we will pay a net fee of 1.75% per annum on letters of credit issued on this facility. This contingent letter of credit facility was issued directly by a financial institution and does not reduce the available capacity under our credit facility. These parental guarantees and contingent letter of credit facility reduce the amount of cash we may be required to post as collateral. As of November 3, 2011, 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 zero in the event DCP Midstream, LLC’s credit rating were to fall below investment grade.

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, inventory levels, and 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.

We had a working capital deficit of $493.8 million as of September 30, 2011, compared to working capital of $20.8 million as of December 31, 2010. Included in these working capital amounts are net derivative working capital liabilities of $28.0 million and $41.1 million as of September 30, 2011 and December 31, 2010, respectively. The change in working capital is primarily attributable to the conversion of our revolving credit facility, on which we had $476.0 million outstanding as of September 30, 2011, from long-term to short-term and the factors described above. We expect that our future working capital requirements will be impacted by these same factors.

As of September 30, 2011, we had $2.0 million in cash and cash equivalents. Of this balance, $1.3 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. In 2010, Congress passed the Dodd-Frank Wall Street Reform and Consumer Protection Act, which has the potential to impact our cash collateral and reporting requirements for our trading activities and derivative positions depending on the final regulations adopted by the United States Commodity Futures Trading Commission and the U.S. Securities and Exchange Commission.

Cash Flow — Operating, investing and financing activities was as follows:

	Nine Months Ended September 30,	
	2011	2010
	(Millions)	
Net cash provided by operating activities	$ 148.9	$ 136.9
Net cash used in investing activities	$(232.6)	$(154.9)
Net cash provided by financing activities	$ 79.0	$ 27.7

Our predecessor's sources of liquidity, prior to its acquisition by us, included cash generated from operations and funding from DCP Midstream, LLC. Our predecessor's cash receipts were deposited in DCP Midstream, LLC's bank accounts and all cash disbursements were made from these accounts. Cash transactions for our predecessor were handled by DCP Midstream, LLC and were reflected in partners' equity as net changes in parent advances to predecessors from DCP Midstream, LLC.

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 paid approximately $23.9 million for our net hedge cash settlements for the nine months ended September 30, 2011 and received $0.1 million for the nine months ended September 30, 2010. On April 18, 2011, we made an estimated federal tax payment of $29.3 million related to our acquisition of Marysville and the conversion of the entity's organizational structure from a corporation to a limited liability company. In addition, we received $5.8 million from DCP Midstream, LLC, related to the sale of surplus equipment as of September 30, 2010.

We received cash distributions from unconsolidated affiliates of $36.3 million and $30.4 million during the nine months ended September 30, 2011 and 2010, respectively. Distributions exceeded earnings by $7.7 million and $1.4 million for the nine months ended September 30, 2011 and 2010, respectively.

Net Cash Used in Investing Activities — Net cash used in investing activities during the nine months ended September 30, 2011 was comprised of: (1) acquisition expenditures of $29.6 million related to our acquisition of our DJ Basin NGL Fractionators, $23.4 million related to construction of our Eagle Plant, and a payment of $7.5 million to the seller of Michigan Pipeline & Processing, LLC in relation to our contingent payment agreement; (2) acquisition expenditures of $114.3 million, representing the carrying value of the net assets acquired, related to our acquisition of Southeast Texas; (3) capital expenditures of $46.4 million (our portion of which was $36.8 million and the noncontrolling interest holders' portion was $9.6 million); and (4) investments in unconsolidated affiliates of $13.2 million; partially offset by (5) a return of investment from unconsolidated affiliates of $1.6 million; and (6) proceeds from sales of assets of $0.2 million.

Net cash used in investing activities during the nine months ended September 30, 2010 was comprised of: (1) acquisition expenditures of $103.8 million related to our acquisition of Atlantic Energy, the Wattenberg NGL pipeline and an additional 55% interest in Black Lake; (2) capital expenditures of $37.1 million (our portion of which was $23.9 million and the noncontrolling interest holders' portion was $13.2 million); and (3) investments in unconsolidated affiliates of $27.0 million, consisting of our predecessor’s investment in Southeast Texas of $26.3 million to fund the acquisition of the Raywood processing plant and Liberty gathering system and investments in Discover of $0.7 million; partially offset by (4) net proceeds from sale of available-for-sale securities of $10.1 million; (5) proceeds from sale of assets of $1.7 million; and (6) a return of investment from Discovery of $1.2 million.

Net Cash Provided by (Used in) Financing Activities — Net cash provided by financing activities during the nine months ended September, 2011 was comprised of: (1) proceeds from the issuance of common units net of offering costs of $152.0 million; (2) net borrowing of debt of $78.0 million; and (3) contributions from noncontrolling interests of $9.1 million; partially offset by (4) distributions to our unitholders and general partner of $97.5 million; (5) excess purchase price over the acquired net assets of Southeast Texas of $35.7 million; (6) distributions to noncontrolling interests of $26.8 million; and (7) payment of deferred financing costs of $0.1 million.

Net cash provided by financing activities during the nine months ended September 30, 2010 was comprised of: (1) proceeds from the issuance of common units net of offering costs of $93.2 million; (2) a net change in advances to predecessor from DCP Midstream, LLC of $19.8 million; and (3) contributions from noncontrolling interests of $10.4 million; partially offset by (4) distributions to our unitholders and general partner of $74.4 million; (5) distributions to noncontrolling interests of $16.0 million; (6) purchase of additional interest in a subsidiary of $3.5 million; (7) payment of deferred financing costs of $1.6 million; and (8) net repayment of debt of $0.2 million.

During the nine months ended September 30, 2011, total outstanding indebtedness under our $850.0 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 $425.5 million and did not exceed $591.1 million. The weighted-average indebtedness outstanding for the nine months ended September 30, 2011 was $485.5 million.

We had unused revolver capacity, which is available commitments under the Credit Agreement, of $372.9 million as of September 30, 2011.

During the nine months ended September 30, 2011, we had the following net movements on our revolving credit facility:

- $150.0 million borrowing to fund the acquisition of our 33.33% interest in Southeast Texas;
- $30.0 million borrowing to fund the purchase of the DJ Basin NGL Fractionators;
- $29.3 million borrowing to fund the Marysville tax payment; and
- $23.4 million borrowing to fund the purchase of certain tangible assets and land located in the Eagle Ford Shale; partially offset by
- $139.7 million repayment financed by the issue of 3,596,636 common units in March 2011;
- $12.5 million repayment financed by the issue of 345,031 common units in the third quarter of 2011; and
- $2.5 million net repayments.

During the nine months ended September, 2010, we had the following net movements on our revolving credit facility:

- 247.8 million repayment financed by the issuance of $250.0 million of our 3.25% Senior Notes due October 1, 2015;
- $93.1 million repayment financed by the issuance of 2,990,000 common units in August 2010; and
- $14.0 million net repayments; partially offset by
- $66.3 million borrowing to fund the acquisition of Atlantic Energy, which includes $17.3 million for propane inventory and working capital;
- $22.0 million borrowing to fund the acquisition of the Wattenberg pipeline;

- $16.6 million borrowing to fund the acquisition of an additional 55% interest in Black Lake; and
- $10.0 million borrowing to fund repayment of our term loan facility.

During the nine months ended September 30, 2010, we had a repayment of $10.0 million on our term loan facility and released $10.0 million of restricted investments which were required as collateral for the facility.

We expect the payment of distributions to our unitholders and general partner to be a significant use of cash from financing activities. See Note 11 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, including certain system integrity and safety improvements, or acquire or construct new capital assets if such expenditures are made to maintain, including over the long-term, our operating or earnings capacity; 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 or earnings capacity.

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. In 2011, we anticipate maintenance capital expenditures of between $10.0 million and $15.0 million, and expenditures for expansion capital of between $35.0 million and $50.0 million, including $10.0 million for the expansion of storage capacity at our Southeast Texas system. We additionally plan to construct the Eagle Plant for approximately $120.0 million, with capital expenditures to be incurred by the fourth quarter of 2012 when the plant is expected to be online. The board of directors may approve additional growth capital during the year, at their discretion.

The following table summarizes our maintenance and expansion capital expenditures for our consolidated entities.

	Nine months ended September 30, 2011			Nine months ended September 30, 2010		
	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures	Maintenance Capital Expenditures	Expansion Capital Expenditures	Total Consolidated Capital Expenditures
		(Millions)			(Millions)	
Our portion	$ 6.6	$ 30.2	$ 36.8	$ 4.1	$ 19.8	$ 23.9
Noncontrolling interest portion	3.7	5.9	9.6	4.9	8.3	13.2
Total	$ 10.3	36.1	$ 46.4	$ 9.0	$ 28.1	$ 37.1

In addition, we invested cash in unconsolidated affiliates of $13.2 million and $27.0 million during the nine months ended September 30, 2011 and 2010, respectively, to fund our share of capital expansion projects. Our expansion capital improvements forecast includes $10.0 million of expenditures, shown as investments in unconsolidated affiliates, for capital improvements related to our January 2011 Southeast Texas acquisition.

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 debt and common unit issuances, to fund our acquisition and expansion capital expenditures.

We expect to fund future capital expenditures with funds generated from our operations, borrowings under our credit facility and the issuance of additional partnership units or the issuance of long-term debt. If these sources are not sufficient, we will reduce our discretionary spending.

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 $97.5 million during the nine months ended September 30, 2011, as compared to $74.4 million for the same period in 2010. We intend to continue making 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 — The Credit Agreement consists of an $850.0 million revolving credit facility as of September 30, 2011. The Credit Agreement matures on June 21, 2012. As of September 30, 2011, the outstanding balance on the revolving credit facility was $476.0 million resulting in unused revolver capacity of $372.9 million, of which approximately $346.0 million was available for general working capital purposes.

Our obligations under the revolving credit facility are unsecured. The unused portion of the revolving credit facility may be used for letters of credit. As of September 30, 2011 and December 31, 2010, we had $1.1 million and $32.1 million, respectively, of outstanding letters of credit issued under the Credit Agreement.

The term loan facility, which was repaid during the first quarter of 2010, was secured at all times by high-grade securities, in an amount equal to or greater than the outstanding principal amount of the term loan. Upon the repayment of term loan facility during the first quarter of 2010, the amount of our revolving credit facility increased by the amount repaid.

As of September 30, 2011, the weighted-average interest rate on our revolving credit facility was 0.75% per annum, excluding the impact of interest rate swaps.

Description of Debt Securities – On September 30, 2010, we issued $250.0 million of our 3.25% Senior Notes due October 1, 2015. We received net proceeds of $247.7 million, net of underwriters' fees, related expense and unamortized discounts of $1.5 million, $0.6 million and $0.2 million, respectively which we used to repay funds borrowed under the revolver portion of our Credit Facility. Interest on the notes will be paid semi-annually on April 1 and October 1 of each year. The notes will mature on October 1, 2015, unless redeemed prior to maturity. The underwriters' fees and related expense are deferred in other long-term assets in our condensed consolidated balance sheets and will be amortized over the term of the notes.

The notes are senior unsecured obligations, ranking equally in right of payment with our existing unsecured indebtedness, including indebtedness under our Credit Facility. We are not required to make mandatory redemption or sinking fund payments with respect to these notes. The securities are redeemable at a premium at our option.

Total Contractual Cash Obligations and Off-Balance Sheet Obligations

A summary of our total contractual cash obligations as of September 30, 2011, is as follows:

	Payments Due by Period (Millions)				
	Total	Less than 1 year	1-3 years	3-5 years	Thereafter
Debt (a)	$ 789.2	$ 501.3	$ 25.5	$ 262.4	$ —
Operating lease obligations (b)	35.6	14.1	16.8	3.6	1.1
Purchase obligations (c)	538.4	358.7	77.8	75.6	26.3
Other long-term liabilities (d)	12.4	—	0.5	0.2	11.7
Total	$1,375.6	$ 874.1	$ 120.6	$ 341.8	$ 39.1

(a) Includes interest payments on debt that has been swapped to a fixed-rate obligation and on debt securities that have been issued. Interest payments on debt that has not been swapped to a fixed-rate obligation are not included as these payments are based on floating interest rates and we cannot determine with accuracy the periodic repayment dates or the amounts of the interest payments.

(b) Our operating lease obligations are contractual obligations, and primarily consist of our leased marine propane terminal and railcar leases, both of which provide supply and storage infrastructure for our Wholesale Propane Logistics business. Operating lease obligations also include firm transportation arrangements and natural gas storage for our Pelico system. The firm transportation arrangements supply off-system natural gas to Pelico and the natural gas storage arrangement enables us to maximize the value between the current price of natural gas and the futures market price of natural gas.

(c) Our purchase obligations are contractual obligations and include purchase orders for capital expenditures, various non-cancelable commitments to purchase physical quantities of propane supply for our Wholesale Propane Logistics business and other items. For contracts where the price paid is based on an index, the amount is based on the forward market prices as of September 30, 2011. 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.

(d) Other long-term liabilities include $11.3 million of asset retirement obligations and $1.1 million of environmental reserves recognized in the September 30, 2011 condensed consolidated balance sheet.

We have no items that are classified as off balance sheet obligations.

Recent Accounting Pronouncements

***Financial Accounting Standards Board, or FASB, Accounting Standards Update, or ASU, 2011-08 "Intangibles – Goodwill and Other (Topic 350),"* or ASU 2011-08** — In September 2011, the FASB issued ASU 2011-08, which amends Accounting Standards Codification, or ASC, Topic 350 "Intangibles — Goodwill and Other." ASU 2011-08 provides additional guidance on the two-step test for goodwill impairment as previously described in Topic 350 "Intangibles — Goodwill and Other." Under the new guidance, entities may elect to first assess qualitative factors instead of calculating the fair value of a reporting unit unless the entity determines that it is more likely than not the fair value of the reporting unit is less than its carrying value. This ASU is effective for interim and annual goodwill impairment tests performed for fiscal years beginning after December 15, 2011, with early adoption permitted. We elected to adopt ASU 2011-08 for our 2011 annual goodwill impairment test. There was no impact from the adoption of ASU 2011-08 on our condensed consolidated results of operations, cash flows and financial position.

***ASU, 2011-04 "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs",* or ASU 2011-04** — In May 2011, the FASB issued ASU 2011-04 which amends ASC, Topic 820 "Fair Value Measurements and Disclosures" to change the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements, clarify the FASB's intent about the application of existing fair value measurement requirements, and change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The provisions of ASU 2011-04 are effective for us for interim and annual periods beginning after December 15, 2011 and we are currently assessing the impact of adoption on our consolidated results of operations, cash flows and financial position.

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 2010 Form 10-K.

Credit Risk

Our principal customers in the Natural Gas Services segment are large, natural gas marketers 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 and forward-starting interest rate swaps that reduce our exposure to market rate fluctuations by converting variable interest rates on our existing debt to fixed interest rates and locking in rates on our anticipated future fixed-rate debt, respectively. The interest rate swap agreements convert the interest rate associated with the indebtedness outstanding under our revolving credit facility to a fixed-rate obligation, thereby reducing the exposure to market rate fluctuations. The forward-starting interest rate swap agreements lock in the interest rate associated with our anticipated future fixed-rate debt, thereby reducing the exposure to market rate fluctuations prior to issuance.

At September 30, 2011, we had interest rate swap agreements totaling $450.0 million, of which we have designated $425.0 million as cash flow hedges and account for the remaining $25.0 million under the mark-to-market method of accounting. As we generally expect to have variable-rate debt levels equal to or exceeding our swap positions during their term, the entire $450.0 million of these arrangements mitigate our interest rate risk through June 2012, with $150.0 million extending from June 2012 through June 2014. Based on our current operations we believe our interest rate swap agreements mitigate our interest rate risk associated with our variable-rate debt.

At September 30, 2011, we had forward-starting interest rate swap agreements totaling $195.0 million, which we have designated as cash flow hedges. As we anticipate entering into future fixed-rate debt at levels equal to or exceeding our forward-starting swap positions during their term, the entire $195.0 million of these arrangements mitigate a portion of our interest rate risk through the term of our anticipated debt into 2022. Based on our current operations we believe our forward-starting interest rate swap agreements mitigate a portion of our interest rate risk associated with our anticipated future fixed-rate debt.

As of September 30, 2011, the effective weighted-average interest rate on our outstanding debt was 4.0%, taking into account our interest rate swap agreements totaling $450.0 million.

Based on the annualized unhedged borrowings under our credit facility of $51.0 million as of September 30, 2011, 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. For storage services, we receive fees in the form of cash or commodities as payment for these services. We employ established policies and procedures to manage our risks associated with these market fluctuations using various commodity derivatives, including forward contracts, swaps, costless collars 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 fixed price swaps and collar arrangements to mitigate a portion of 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.

We enter into derivative financial instruments to mitigate a portion of the cash flow risk of decreased natural gas, NGL and condensate prices associated with our percent-of-proceeds arrangements and gathering operations. We also may enter into natural gas derivatives to lock in margin around our transportation or leased storage assets. Historically, there has been a strong relationship between NGL prices and crude oil prices, with some recent exceptions and limited liquidity and tenor of the NGL financial market; therefore we have historically used crude oil swaps and costless collars to mitigate a portion of our NGL price risk. For the nearer tenor where there is greater liquidity in the NGL derivatives market, we have periodically also utilized NGL derivatives. When the relationship of NGL prices to crude oil prices is at a discount to historical ranges, we experience additional exposure as a result of the relationship where we utilize crude oil swaps to mitigate NGL price exposure. When our crude oil swaps become short-term in nature, we have periodically converted certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps. As a result of these transactions, we have mitigated a portion of our expected natural gas, NGL and condensate commodity price risk through 2016.

The derivative financial instruments we have entered into are typically referred to as “swap” contracts and “collar” arrangements. The 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 also use commodity collar arrangements, which entitle us to receive payment at settlement from the counterparty to the contract to the extent that the reference price is below the floor price stated in the contract. Conversely, if the reference price is above the ceiling price stated in the contract, we are required to make payment at settlement to the counterparty. If the reference price is between the floor price and the ceiling price, no payment will be made at the settlement of 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.

[Table of Contents](#)

The following tables set forth additional information about our fixed price swaps, and our collar arrangements used to mitigate a portion of our natural gas and NGL price risk associated with our percent-of-proceeds arrangements and our condensate price risk associated with our gathering operations, as of November 3, 2011:

Commodity Swaps

Period	Commodity	Notional Volume - (Short)/Long Positions	Reference Price		Price Range
October 2011 — December 2014	Natural Gas	(500) MMBtu/d	IFERC Monthly Index Price for Colorado Interstate Gas Pipeline (a)	$	5.06/MMBtu
October 2011 — December 2014	Natural Gas	(1000) MMBtu/d	Texas Gas Transmission Price (b)	$	4.87/MMBtu
October 2011 — December 2011	Natural Gas	(400) MMBtu/d	IFERC Monthly Index Price for Houston Ship Channel (d)	$	4.21/MMBtu
October 2011 — December 2011	NGL's	(2,559) Bbls/d	Mt. Belvieu Non-TET (e)	$	0.55-2.52/Gal
January 2012 — March 2012	NGL's	(1,869) Bbls/d	Mt. Belvieu Non-TET (e)	$	1.48-2.19/Gal
April 2012 — December 2012	NGL's	(702) Bbls/d	Mt. Belvieu Non-TET (e)	$	2.20/Gal
October 2011 — December 2011	Crude Oil	(2,200) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$	56.75 - $83.80/Bbl
January 2012 — December 2012	Crude Oil	(2,325) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$	66.72 - $99.85/Bbl
January 2013 — December 2013	Crude Oil	(2,250) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$	67.60 - $99.85/Bbl
January 2014 — December 2014	Crude Oil	(1,500) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$	74.90 - $96.08/Bbl
January 2015 — December 2015	Crude Oil	(1,000) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$	92.00 - $100.04/Bbl
January 2016 — December 2016	Crude Oil	(500) Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$	101.30/Bbl
October 2011 — December 2014	Natural Gas	500 MMBtu/d	Texas Gas Transmission Price (b)	$	4.93/MMBtu
October 2011 — December 2011	Crude Oil	1,620 Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$	93.40 - 109.85/Bbl
January 2012 — March 2012	Crude Oil	1,350 Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$	86.45/Bbl
April 2012 — December 2012	Crude Oil	700 Bbls/d	Asian-pricing of NYMEX crude oil futures (c)	$	92.00/Bbl

(a) The Inside FERC index price for natural gas delivered into the Colorado Interstate Gas (CIG) pipeline.
(b) The Inside FERC index price for natural gas delivered into the Texas Gas Transmission pipeline in the North Louisiana area.
(c) Monthly average of the daily close prices for the prompt month NYMEX light, sweet crude oil futures contract (CL).
(d) The Inside FERC monthly published index price for natural gas delivered into the Houston Ship Channel area.
(e) The average monthly OPIS price for Mt. Belvieu Non-TET.

Commodity Collar Arrangements

Period	Commodity	Notional Volume	Reference Price	Collar Price Range
October 2011 — December 2012	Crude Oil	600 Bbls/d (a)	Asian-pricing of NYMEX crude oil futures (b)	$80.00 - $97.40/Bbl
January 2013 — December 2013	Crude Oil	400 Bbls/d (a)	Asian-pricing of NYMEX crude oil futures (b)	$80.00 - $96.50/Bbl

(a) Reflects separate purchased put and sold call contracts, resulting in a collar arrangement.
(b) Monthly average of the daily close prices for the prompt month NYMEX light, sweet crude oil futures contract (CL).

Our sensitivities for 2011 as shown in the table below are estimated based on our average estimated commodity price exposure and commodity cash flow protection activities for the calendar year 2011, and exclude the impact from non-cash mark-to-market on our commodity derivatives. We utilize crude oil and NGL derivatives to mitigate a portion of our commodity price exposure for NGLs, and show 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.

Commodity Sensitivities Excluding Non-Cash Mark-To-Market

	Per Unit Decrease	Unit of Measurement	Estimated Decrease in Annual Net Income Attributable to Partners (Millions)
Natural gas prices	$1.00	MMBtu	$ 0.4
Crude oil prices (a)	$5.00	Barrel	$ 3.2
NGL to crude oil price relationship (b)	5 percentage point change	Barrel	$ 5.7

(a) Assuming 60% NGL to crude oil price relationship. At crude oil prices outside of our collar range of approximately $80.00 to $97.40, this sensitivity decreases by $0.8 million.

(b) Assuming 60% NGL to crude oil price relationship and $80.00/Bbl crude oil price. Generally, this sensitivity changes by $0.7 million for each $10.00/Bbl change in the price of crude oil. As crude oil prices increase from $80.00/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 $80.00/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 2011 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 Attributable to Partners) (Millions)
Natural gas prices	$ 1.00	MMBtu	$ 1.1
Crude oil prices	$ 5.00	Barrel	$ 12.8
NGL prices	$ 0.10	Gallon	$ 2.1

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. 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 portion of our expected natural gas, NGL and condensate commodity price risk relating to the equity volumes associated with our gathering and processing activities through 2016.

Given the historical relationship between NGL prices and crude oil prices and the limited liquidity and tenor of the NGL financial market, we have generally used crude oil derivative instruments to mitigate a portion of NGL price risk. For the nearer tenor where there is greater liquidity in the NGL derivatives market, we have periodically also utilized NGL derivatives. When the relationship of NGL prices to crude oil prices is at a discount to historical ranges, we experience additional exposure as a result of the relationship where we utilize crude oil swaps to mitigate NGL price exposure. When our crude oil swaps become short-term in nature, we have periodically converted certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps.

Based on historical trends, we generally expect NGL prices to directionally follow changes in crude oil prices over the long-term. However, the pricing relationship between NGLs and crude oil may vary, as we believe crude oil prices 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, whereas NGL prices are more correlated to supply and U.S. petrochemical demand. We believe that future natural gas prices will be influenced by North American supply deliverability, the severity of winter and summer weather, the level of North American production and drilling activity of exploration and production companies and imports of liquid natural gas, or LNG, from foreign locations. Drilling activity can be adversely affected as natural gas prices decrease. Energy market uncertainty could also further reduce North American drilling activity. Limited access to capital could also decrease drilling. Lower drilling levels over a sustained period would reduce natural gas volumes gathered and processed, but could increase commodity prices, if supply were to fall relative to demand levels.

Item 4. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the Securities and Exchange Commission, or the Commission, under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the Commission’s rules and forms, and that information is accumulated and communicated to the management of our general partner, including our general partner’s principal executive and principal financial officers (whom we refer to as the Certifying Officers), as appropriate to allow timely decisions regarding required disclosure. The management of our general partner evaluated, with the participation of the Certifying Officers, the effectiveness of our disclosure controls and procedures as of September 30, 2011, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of September 30, 2011, our disclosure controls and procedures were effective.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2011 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

The information required for this item is provided in Note 17, “Commitments and Contingent Liabilities,” included in Item 8 of our 2010 Form 10-K, which is incorporated by reference into this item.

Item 1A. *Risk Factors*

In addition to the other information set forth in this report, careful consideration should be given to the risk factors discussed in Part I, “Item 1A. Risk Factors” in our 2010 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 2010 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.

Table of Contents

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. 1 to Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP, dated as of April 11, 2008 (attached as Exhibit 4.1 to DCP Midstream Partners, LP's Form 8-K (File No. 001-32678) filed with the SEC on April 14, 2008).
3.6	*	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).
10.1	*	Amended and Restated Credit Agreement, dated June 1, 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 10-Q (File No. 001-32678) filed with the SEC on November 9, 2010).
10.2	*	Twelfth Amendment to Omnibus Agreement, dated January 1, 2011, among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LLC, and DCP Midstream Operating, LP (attached as Exhibit 10.19 to DCP Midstream, LP's Form 10-K (File No. 001-32678) filed with the SEC on March 1, 2011).
10.3	*	First Amendment to Amended and Restated General Partnership Agreement of DCP Southeast Texas, LLC, Gas Supply Resources Holdings, Inc. and DCP Partners SE Texas, LLC (attached as Exhibit 10.22 DCP Midstream, LP's Form 10-K (File No. 001-32678) filed with the SEC on March 1, 2011).
10.4++		Gas Processing Contract between DCP Midstream, LP and DCP Midstream Partners, LP dated as of August 1, 2011.
12.1		Ratio of Earnings to Fixed Charges.
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.
101		Financial statements from the Quarterly Report on Form 10-Q of DCP Midstream Partners, LP for the quarterly period ended September 30, 2011, formatted in XBRL: (i) the Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations, (iii) the Condensed Consolidated Statements of Comprehensive Income, (iv) the Condensed Consolidated Statements of Cash Flows, (v) the Condensed Consolidated Statements of Changes in Equity and (vi) the Notes to the Condensed Consolidated Financial Statements.

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

++ Confidential treatment has been requested with respect to portions of the exhibit. Such portions have been redacted and filed separately with the SEC.

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 November 9, 2011.

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)

EXHIBIT INDEX

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. 1 to Second Amended and Restated Agreement of Limited Partnership of DCP Midstream Partners, LP, dated as of April 11, 2008 (attached as Exhibit 4.1 to DCP Midstream Partners, LP's Form 8-K (File No. 001-32678) filed with the SEC on April 14, 2008).
3.6	*	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).
10.1	*	Amended and Restated Credit Agreement, dated June 1, 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 10-Q (File No. 001-32678) filed with the SEC on November 9, 2010).
10.2	*	Twelfth Amendment to Omnibus Agreement, dated January 1, 2011, among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LLC, and DCP Midstream Operating, LP (attached as Exhibit 10.19 to DCP Midstream, LP's Form 10-K (File No. 001-32678) filed with the SEC on March 1, 2011).
10.3	*	First Amendment to Amended and Restated General Partnership Agreement of DCP Southeast Texas, LLC, Gas Supply Resources Holdings, Inc. and DCP Partners SE Texas, LLC (attached as Exhibit 10.22 DCP Midstream, LP's Form 10-K (File No. 001-32678) filed with the SEC on March 1, 2011).
10.4++		Gas Processing Contract between DCP Midstream, LP and DCP Midstream Partners, LP dated as of August 1, 2011.
12.1		Ratio of Earnings to Fixed Charges.
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.
101		Financial statements from the Quarterly Report on Form 10-Q of DCP Midstream Partners, LP for the quarterly period ended September 30, 2011, formatted in XBRL: (i) the Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations, (iii) the Condensed Consolidated Statements of Comprehensive Income, (iv) the Condensed Consolidated Statements of Cash Flows, (v) the Condensed Consolidated Statements of Changes in Equity and (vi) the Notes to the Condensed Consolidated Financial Statements.

* Such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.
++ Confidential treatment has been requested with respect to portions of the exhibit. Such portions have been redacted and filed separately with the SEC.

Exhibit 10.4

Portions of this Exhibit have been redacted pursuant to a request for confidential treatment under Rule 24b-2 of the General Rules and Regulations under the Securities Exchange Act. Omitted information, marked "[***]" in this Exhibit has been filed with the Securities and Exchange Commission together with such request for confidential treatment.

GAS PROCESSING CONTRACT
Between DCP MIDSTREAM, LP as Supplier and
DCP MIDSTREAM PARTNERS, LP as Processor
Dated as of August 1, 2011

INDEX

SECTION		PAGE
1.	COMMITMENT	1
2.	DELIVERY AND REDELIVERY POINTS	2
3.	DELIVERY PRESSURE	2
4.	QUANTITY	3
5.	PROCESSING CONSIDERATION	4
6.	TERM	6
7.	ADDRESSES AND NOTICES	6
8.	TERMINATION OF PRIOR CONTRACTS AND RELEASE	7
	SIGNATURE PAGE	7

EXHIBIT A
GENERAL TERMS AND CONDITIONS

A.	DEFINITIONS	A-1
B.	DELIVERY DATE; COMPRESSION	A-1
C.	RESERVATIONS OF SUPPLIER	A-1
D.	METERING AND MEASUREMENT	A-1
E.	DETERMINATION OF GAS COMPOSITION, GRAVITY, AND HEATING VALUE	A-2
F.	QUALITY OF GAS	A-2
G.	BILLING AND PAYMENT	A-3
H.	FORCE MAJEURE	A-4
I.	WARRANTY OF TITLE	A-4
J.	ROYALTY AND OTHER INTERESTS	A-4
K.	TAX RESPONSIBILITIES	A-4
L.	INDEMNIFICATION AND RESPONSIBILITY FOR INJURY OR DAMAGE	A-5
M.	RIGHT OF WAY	A-5
N.	ASSIGNMENT	A-5
O.	MISCELLANEOUS PROVISIONS	A-5

EXHIBIT B
PROCESSING FEE ADJUSTMENTS

EXHIBITS C-1 and C-2
DELIVERY AND REDELIVERY POINTS

EXHIBIT D
PLANT SPECIFICATIONS

GAS PROCESSING CONTRACT

This Gas Gathering and Processing Contract ("Contract") is entered as of August 1, 2011, between **DCP MIDSTREAM, LP** ("Supplier") and **DCP MIDSTREAM PARTNERS, LP** ("Processor").

In consideration of the mutual covenants contained herein, the parties agree as follows:

1. COMMITMENT.

(a) Plant Construction. Processor will cause construction of a new nominal 200 MMcf/Day capacity cryogenic gas processing plant at a 161 acre site in the Southeast Quarter of Survey No. One, Block No. One of the International & Great Northern Railroad Company Survey, Abstract 172, Jackson County, Texas near Edna, Texas on property previously owned by Supplier ("Site"), to be known as the Eagle Plant ("Plant"). Supplier has transferred the Plant Site property to its former Affiliate DCP Eagle Plant LLC ("DCP Eagle") by the terms of a Special Warranty Deed dated August 1, 2011. As of December 29, 2010, Supplier procured from Valerus Compression Services, LP ("Valerus") the central processing unit that is to form the core processing unit for the new Plant (the "Eagle Plant Skid"). The Eagle Plant Skid was constructed in 2009 by T.H. Russell and has not previously been placed into operation. Supplier transferred the Eagle Plant Skid to DCP Eagle by a Bill of Sale also dated as of August 1, 2011. Supplier sold all of the issued and outstanding ownership interests of DCP Eagle to Processor under a Purchase and Sale Agreement dated August 1, 2011. Processor agrees to promptly cause DCP Eagle to install the Eagle Plant Skid and to promptly construct the remainder of the Plant at the Site. The plans and construction activities for installation of the Eagle Plant Skid and all other Plant components, including all specifications and contractor selections, shall be subject to approval by Supplier. Without limitation, the additional Plant components to be installed will include raw gas delivery point connections with gathering systems of Supplier and the south Texas line of Trunkline Gas Company, LP ("Trunkline"), inlet gas measurement and analysis, dehydration, mol sieves, compression, Residue Gas delivery points to the facilities of Trunkline, a NGLs pipeline connection with either DCP Sandhills Pipeline, LLC or Wilbreeze Pipeline, LLC, and all other components and equipment deemed necessary or appropriate by the parties. The Plant design will be consistent with those stated in Exhibit D. Any changes in Exhibit D Plant design specifications and all direct contractor selections will be subject to approval by Supplier. Processor will use all reasonable efforts to cause DCP Eagle to complete construction of the Plant and to place it into operation no later than November 1, 2012. On or before the In Service Date, Processor will assign this Contract to DCP Eagle. Processor will remain responsible following the assignment for performance of this Contract notwithstanding the assignment.

(b) <u>Supplier's Commitment</u>. Supplier owns and controls quantities of processable gas handled in various south and central Texas gas gathering systems owned by Supplier or its Affiliates. Supplier has agreements with Trunkline to enable deliveries to the Plant of south Texas gas owned or controlled by Supplier and others. Supplier will use its good faith reasonable efforts to deliver volumes of raw gas to Processor for processing, but Supplier may deliver raw gas to its other area gas processing plants in its sole discretion. Supplier does not guaranty delivery for processing of any specific minimum quantity of raw gas. Supplier retains title to and may remove from its gathering system and retain all condensate, drips, and Inferior Liquids from the gathering system prior to delivery of raw gas for processing, and Supplier may handle, sell, and dispose of gathering system liquids independently from this Contract.

(c) Processor's Commitment. Processor commits and will cause DCP Eagle to reserve the capacity of the Plant available to Supplier, and within the Plant's capabilities Processor will receive, process, and return to Supplier or for Supplier's benefit all Residue Gas, NGLs, and any other marketable products recovered in Plant operations attributable to gas delivered by Supplier. Processor may undertake to process gas for third parties at the Plant only on a fully interruptible basis using any capacity not being used from Day to Day for the processing of Supplier's gas.

(d) <u>Exhibits</u>. Definitions and General Terms and Conditions included in this Contract are attached as Exhibit A. Certain processing fee adjustment provisions are stated in Exhibit B. Delivery and Redelivery Points are stated in Exhibits C-1 and C-2. Plant design specifications are stated in Exhibit D. All Exhibits referenced herein are attached and incorporated by reference.

2. <u>DELIVERY AND REDELIVERY POINTS</u>. Supplier's Plant inlet Delivery Points and Plant outlet Redelivery Points are stated in Exhibits C-1 and C-2, respectively. Title to the portion of the gas delivered that is to be used by Processor for Plant fuel use and Supplier's pro rata share of any Plant unaccountable volumes will pass to and vest in Processor at the Delivery Points. Supplier otherwise reserves and retains title to all gas delivered and to the Residue Gas and NGLs attributable to Supplier's deliveries.

3. <u>DELIVERY AND REDELIVERY PRESSURES</u>. Supplier will deliver or cause delivery of the gas at the Delivery Points at a pressure sufficient to enable it to enter Processor's Facilities against the working pressure at reasonably uniform rates of delivery. The design of the gathering system and Plant are for delivery pressures at 500 psig at the Plant inlet. Changes from this operating standard must be agreed by both parties. Processor will deliver Residue Gas at the Redelivery Points at a pressure sufficient to enable them to enter the downstream pipelines against the working pressure at reasonably uniform rates of delivery, not to exceed the maximum allowable operating pressure established by the downstream pipelines, up to a maximum pressure for Residue Gas of 1100 psig and 1345 psig for NGLs.

4. QUANTITY. (a) Firm Quantity Deliveries. Supplier may deliver, and within Plant capacity, operating conditions, and capabilities Processor shall take all of Supplier's gas tendered by Processor at the Delivery Points. Processor will use commercially reasonable efforts to operate its facilities in an effort to maintain consistent takes of all available quantities.

(b) Supplier to take and market Residue Gas and NGLs. Supplier shall take its share of Residue Gas and NGLs in kind timely at the Redelivery Points. The parties recognize that Processor has no Residue Gas storage and very little if any NGL storage. Processor agrees to deliver to or for the account of Supplier Supplier's Residue Gas and allocable NGLs. Supplier's must receive and transport or cause to be received and transported when produced and available the Residue Gas and NGLs allocable to Supplier's raw gas deliveries. Supplier is solely responsible for all arrangements for receipt and transportation of its in kind Residue Gas, any bypassed gas, and NGLs. Supplier shall make or cause its customers to make all arrangements with the downstream gas and NGL pipelines, and shall ensure that its desired nominations for downstream transportation are properly and timely placed with the downstream pipelines in accordance with their nomination and confirmation procedures. Each party will endeavor to provide the other party prompt notice of scheduled maintenance, construction, and other material operational events (other than weather) that will affect volumes materially, including but not limited to facility outages and operational changes.

(c) Volumes Not Taken or Marketed by Supplier. If Supplier fails, for any reason, to take in kind or otherwise dispose of all or any part of Supplier's share of Residue Gas or NGLs, to avoid curtailing or discontinuing operation of the Plant, Processor shall have the option, but not the obligation, to sell or otherwise dispose in any manner necessary Supplier's share of Residue Gas or NGLs not timely taken in kind or otherwise disposed of by Supplier; provided that Processor shall account to and timely pay Supplier for any proceeds received by Processor from a sale or disposition less reasonable transportation, storage, fractionation, and other charges and marketing fees paid by Processor to third parties. Supplier recognizes these sales may be distress sales at below market prices.

(d) Gas Not Taken By Processor. Supplier may dispose of any gas not taken by Processor at the Delivery Points for any reason, including events of Force Majeure, subject to Processor's right to resume takes at any subsequent time.

5. PROCESSING CONSIDERATION.

5.1 Processing Consideration. As full consideration for Processor's receipt, processing, redelivery, and accounting for the gas and all its components delivered to Processor each month, Supplier shall pay Processor:

(a) Commencing on the In Service Date, a monthly firm processing capacity reservation charge of **$[***]** per Mcf times **[***]** MMcf/Day ($**[***]**/day) subject to adjustment as provided in Section 5.1(e) and (f) below ("Demand Charge"). Supplier shall not be entitled to a suspension or adjustment in the Demand Charge due to: (i) an event of Force Majeure claimed by Supplier, (ii) any failure of supply or inability on the part of Trunkline to deliver gas to the Plant, (iii) the inability of downstream service providers to accept gas or NGLs conforming to the quality specifications, or (iv) a downstream Force Majeure event.

(b) A throughput fee of **$[***]**per Mcf of gas delivered by Supplier to Processor for processing at the Plant, subject to adjustment as provided in Section 5.1(e) below ("Throughput Fee").

(c) A monthly electricity cost recovery payment of the actual amount of all electricity costs incurred by Processor for operation of the Plant for the month times the fraction whose numerator is the month's gas quantities supplied by Supplier and whose denominator is the month's gas quantities supplied to the Plant by all persons making deliveries to the Plant including Supplier.

(d) The fees under (a) and (b) above will be adjusted on the first anniversary of the In Service Date and on each annual anniversary date thereafter by a percentage equal to **[***]** of the annual percentage of change in the Producer Price Index – Finished Goods, Unadjusted published by U.S. Department of Labor or its successor ("PPI"), comparing the latest published data with the comparable data for the previous year, provided the Demand Charge and Throughput Fee shall never be less than the initial amounts set for them in Section 5.1(a) and (b).

(e) The Demand Charge and Throughput Fee shall be adjusted as of the In Service Date based on the actual construction cost of the Plant as set forth in Exhibit B.

(f) The Demand Charge shall be reduced for any Day in which the gas volumes delivered by Supplier are curtailed in whole or in part due to the unavailability of the Plant for reasons of Force Majeure, maintenance, a casualty loss, or otherwise; provided the lack of availability of processing service exceeds more than 12 hours in a Day and occurs for more than 12 Days on a cumulative basis over the Contract year beginning as of the In Service Date or its current anniversary. Once the cumulative 12 Days is reached in a Contract year, the Demand Charge will be reduced for each applicable Day of the remainder of the Contract year by a fraction whose numerator is the negative difference between **[***]** MMcf/Day and the Day's volume actually processed and whose denominator is **[***]** MMcf, times the Section 5.1(a) Demand Charge component of $**[***]** per Mcf as adjusted for the current Contract year.

5.2 <u>In Kind Redeliveries</u>. Subject to the other terms and conditions of this Contract, Processor will redeliver in kind to Supplier or its nominee at the applicable Redelivery Point 100% of the Residue Gas and NGLs attributable to Supplier's gas deliveries. No separate payment or value calculation is to be made under this Contract for helium, sulfur, CO_2, or other non-hydrocarbons.

5.3 <u>Allocation of Residue Gas and NGLs</u>. If Processor has no third party customers, Processor will allocate all Residue Gas and NGLs from the Plant to Supplier. If Processor has third party customers delivering gas for processing during the month, Processor will determine the Residue Gas and NGLs attributable to Supplier using the following definitions and procedures. Additional definitions are in Section A of Exhibit A. From time to time upon notice to Supplier, Processor may make changes and adjustments in its allocation methods as necessary to improve accuracy or efficiency.

(a) <u>NGLs Allocable to Supplier</u>. Processor will determine the quantity of each NGL component allocable to Supplier's gas by multiplying the total quantity of each NGL component recovered at the Plant by a fraction. The numerator will be the gallons of that NGL component contained in the gas delivered by Supplier, determined by chromatographic analysis or other accepted method in the industry, and the denominator will be the total gallons of that component contained in all gas delivered to Processor from sources connected directly at the inlet to Processor's Facilities.

(b) <u>Residue Gas Allocable to Supplier</u>.

(i) Processor will determine the MMBtus of "<u>Residue Gas allocable to Supplier</u>" by multiplying the MMBtus of "Residue Gas available" from Processor's Facilities by a fraction. The numerator will be the "theoretical MMBtus of Residue Gas remaining from Supplier's gas" delivered by Supplier, and the denominator will be the total of the theoretical MMBtus of Residue Gas remaining from all gas delivered to Processor from the common sources connected to Processor's Facilities. "<u>Residue Gas available</u>" means all remaining Residue Gas available from Processor's Facilities, net of gas used for the operation of Processor's Facilities (including Plant fuel use and lost/unaccounted for volumes).

"<u>Theoretical MMBtus of Residue Gas remaining from Supplier's gas</u>" means the sum of the MMBtus of methane and heavier hydrocarbons contained in Supplier's gas, determined by chromatographic analysis or other accepted method in the industry, less the MMBtus of recovered NGLs attributable to Supplier's gas.

5.4 Taxes and Assessments. Processor may increase its fees as necessary to recover the cost of any tax, assessment, or other charge imposed by a governing authority on Processor directly relating to the handling of Supplier's gas or to the ownership or operation of Processor's Facilities, other than ad valorem taxes and taxes based on Processor's income or right to do business.

5.5 Plant Operations. Processor reserves the right temporarily to suspend, alter, or modify Plant operations at any time and from time to time for any reason without liability or obligation to Supplier, subject to Section 5.1(a) and (f). However, Processor will operate the Plant as a prudent operator, consistently with the Plant design in Exhibit D, and in ways that maximize the value of Supplier's Gas and NGLs; including, but not limited to preventive maintenance, promptly making needed repairs, and acting in accordance with Supplier's reasonable requests regarding any bypass of gas around the Plant and operations in an ethane rejection mode rather than in an ethane recovery mode.

5.6 New Delivery Points, Plant Modifications, and Expansions. Supplier may request that Processor construct new Residue Gas and NGLs Delivery Points, other Plant modifications, and Plant expansions from time to time, and Processor will promptly make the requested changes in return for an adjustment in the Processing Fees that appropriately compensates Processor for its incremental investment in those projects, to be negotiated in good faith between the parties at the time in a manner consistent with the initial negotiation of this Contract.

6. TERM. This Contract shall be in force for a primary term of 15 years from the In Service Date, and from year to year thereafter until canceled by either party as of the end of the primary term, or any subsequent anniversary, on three years' advance written notice.

7. ADDRESSES AND NOTICES. Either party may give notices to the other party by first class mail postage prepaid, by overnight delivery service, or by facsimile with receipt confirmed at the following addresses or other addresses furnished by a party by written notice. Unless Supplier objects in writing, Processor may also use Supplier's current address for invoices for notice purposes. Any telephone numbers below are solely for information and are not for Contract notices. The parties opt out of electronic delivery of notices and amendments under this Contract, except that notices and hand-signed amendments may be delivered by facsimile with receipt confirmed as stated above.

Notices to Supplier - Correspondence	DCP Midstream, LP Attn: Managing Director, South Texas 5718 Westheimer Road, Suite 1900 Houston, Texas 77057 Phone: (713) 735-3613 Fax: (713) 627-6613

Notices to Supplier – Payments:	Via intercompany transfer as long as Supplier and Processor remain affiliated; if not, then by wire transfer to the bank and account that Supplier will designate in writing to Processor.
Notices to Processor – Billings & Statements:	DCP Midstream Partners, LP Attn: Revenue Accounting 370 17th Street, Suite 2500 Denver, CO 80202 Phone: (303) 633-2922 Fax: (303) 633-2921
Notices to Processor – Correspondence	DCP Midstream Partners, LP Attn: Contract Administration 370 17th Street, Suite 2500 Denver, CO 80202 Phone: (303) 633-2900 Fax: (303) 633-2921
Notices to Processor – Payments:	Via intercompany transfer as long as Supplier and Processor remain affiliated; if not, then by wire transfer to the bank and account that Processor will designate in writing to Supplier.

The parties have signed this Contract by their duly authorized representatives as of the date first stated above.

DCP MIDSTREAM, LP	**DCP MIDSTREAM PARTNERS, LP** **By: DCP MIDSTREAM GP, LP** **Its: General Partner** **By: DCP MIDSTREAM GP, LLC** **Its: General Partner**
By /s/ Richard A. Bradsby, II Richard A. Bradsby, II, Vice President	By /s/ Mark A. Borer Mark A. Borer, President and CEO
Signed on August 1, 2011 Supplier	Signed on: August 1, 2011 Processor

Signature Sheet for Gas Gathering and Processing Contract
Dated as of August 1, 2011

EXHIBIT A

To GAS GATHERING AND PROCESSING CONTRACT
Between DCP MIDSTREAM, LP as Supplier and
DCP MIDSTREAM PARTNERS, LP as Processor
Dated as of August 1, 2011

GENERAL TERMS AND CONDITIONS

A. DEFINITIONS

Except where the context indicates a different meaning or intent, and whether or not capitalized, the following terms will have meanings as follows:

a. <u>Affiliate</u> – a company (i) in which a party owns directly or indirectly 50% or more of the issued and outstanding voting stock or other equity interests; (ii) which owns directly or indirectly 50% or more of the issued and outstanding voting stock or equity interests of the party; and (iii) in which a company described in (ii) owns, directly or indirectly, 50% or more of the issued and outstanding voting stock or other equity interests.

b. <u>Btu</u> – British thermal unit. <u>MMBtu</u> – one million Btus.

c. <u>Day</u> – a period of 24 consecutive hours beginning and ending at 9:00 a.m. local time, or other 24 hour period designated by Processor and a downstream pipeline.

d. <u>Delivery Points</u> – whether one or more, see Sections 2, Exhibit A Sections B.1 and B.2, and Exhibit C-1.

e. <u>Facilities</u> – Processor’s Eagle Plant, Jackson County, Texas.

f. <u>Force Majeure</u> – see Section H.2 below.

g. <u>Gas</u> or <u>gas</u> – all natural gas that arrives at the surface in the gaseous phase, including all hydrocarbon and non-hydrocarbon components, casinghead gas produced from oil wells, gas well gas, and stock tank vapors.

h. <u>GPM</u> – NGL gallons per Mcf.

i. <u>Inferior Liquids</u> – Mixed crude oil, slop oil, salt water, nuisance liquids, and other liquids recovered by Supplier in its gathering system or by either party at Plant inlet receivers. Supplier will retain revenues from Inferior Liquids, drips, and other gathering system or pipeline liquids to defray costs of treating and handling; Processor is not entitled to and will not allocate or account for those liquids.

j. <u>In Service Date</u> – the first day of the month following the date on which Processor has completed construction and testing of the Plant and the subsequent operation of the Plant in accordance with the design specifications for a period of 10 consecutive days.

k. <u>Mcf</u> – 1,000 cubic feet of gas at standard base conditions of 60ºF and 14.73 psia.

l. <u>MMcf</u> – 1,000 Mcf.

m. <u>Month</u> or <u>month</u> – a calendar month beginning on the first Day of a Month.

n. <u>NGL</u> or <u>NGLs</u> – natural gas liquids, or ethane and heavier liquefiable hydrocarbons separated from gas and any incidental methane in NGL after processing.

o. <u>psi</u> – pounds per square inch; <u>psia</u> – psi absolute; <u>psig</u> – psi gauge.

p. <u>Redelivery Points</u> – See Section 2 and Exhibit C-2.

q. <u>Residue Gas</u> – merchantable hydrocarbon gas remaining after processing (after all reductions, including Plant fuel and lost and unaccounted for gas), and hydrocarbon gas sold or delivered without first being processed.

r. <u>TET</u> – price quotes for NGL on the Texas Eastern Products Pipeline Company, LLC system.

s. <u>TF&S</u> – NGL transportation, fractionation, and storage.

B. DELIVERY DATE; COMPRESSION

B.1 <u>Delivery Date</u>. Deliveries under this Contract will commence as of the In Service Date of the Plant and of all pipeline connections.

B.2 <u>Delivery Rates</u>. Under normal conditions, Supplier and Processor will deliver and receive gas at reasonably uniform rates of delivery. Processor will have agents or employees available at all reasonable times to receive advice and directions from Supplier for changes in the rates of delivery of gas as required from time to time.

B.4 <u>Options to Compress</u>. If Supplier’s or Trunkline’s facilities become incapable of delivering gas into Processor’s Facilities, neither party will be obligated to compress, but either party will have the option to do so. If neither party elects to compress within a reasonable time after the need for compression appears, Processor upon written request of Supplier will either arrange promptly to provide compression at a reasonable fee and actual fuel charge to be negotiated between the parties.

C. RESERVATIONS OF SUPPLIER

Omitted.

D. METERING AND MEASUREMENT

D.1 <u>Processor to Install Meters</u>. Processor will own, maintain, and operate orifice meters or other measuring devices of standard make at or near the Delivery Points. Except as otherwise stated in this Section D, Processor will install orifice meters or other measurement devices and compute volumes in accordance with accepted industry practice. A party providing compression facilities will also provide sufficient pulsation dampening equipment to prevent pulsation from affecting measurement at the Delivery Points. The parties will use electronic recording devices. Supplier will have access to Processor's metering equipment at reasonable hours, but only Processor will calibrate, adjust, operate, and maintain it.

D.2 Unit of Volume. The unit of volume will be one cubic foot of gas at a base temperature of 60° F. and at a pressure base of 14.73 psia. Computations of volumes will follow industry accepted practice.

D.3 Pressure, Temperature. Processor may measure the atmospheric pressure or may assume the atmospheric pressure to be 14.7 psia. Processor may determine the gas temperature by using a recording thermometer; otherwise, the temperature will be assumed to be 60° F.

D.4 Check Meters. Supplier may install, maintain, and operate in accordance with accepted industry practice at its own expense pressure regulators and check measuring equipment of standard make using separate taps. Check meters shall not interfere with operation of Processor's equipment. Processor will have access to Supplier's check measuring equipment at all reasonable hours, but only Supplier will calibrate, adjust, operate, and maintain it. If Supplier chooses not to install check measurement, Processor will give Supplier access to data for Supplier's SCADA.

D.5 Meter Tests. At least monthly, Processor will verify the accuracy of Processor's measuring equipment, and Supplier will verify the accuracy of any check measuring equipment. If Supplier or Processor notifies the other that it desires a special test of any measuring equipment, they will cooperate to secure a prompt verification of the accuracy of the equipment. If either party at any time observes a variation between the delivery meter and the check meter, it will promptly notify the other, and both will then cooperate to secure an immediate verification of the accuracy of the equipment. Processor will give Supplier reasonable advance notice of the time of all special tests and calibrations of meters and of sampling for determinations of gas composition and quality, so that Supplier may have representatives present to witness tests and sampling or make joint tests and obtain samples with its own equipment. Supplier will give reasonable advance notice to Processor of the time of tests and calibrations of any check meters and of any sampling by Supplier for determination of gas composition and quality.

D.6 Correction of Errors. If at any time any of the measuring or testing equipment is found out of service or registering inaccurately in any percentage, the measuring party will adjusted it promptly to read accurately within the limits prescribed by the manufacturer. If any measuring equipment is found to be inaccurate or out of service by an amount exceeding the greater of (i) 2.0 percent at a recording corresponding to the average hourly rate of flow for the period since the last test, or (ii) 100 Mcf per month, the measuring party will correct previous readings to zero error for any known or agreed period. Processor will determine the volume of gas delivered during that period by the first feasible of the following methods:

(i) Using the data recorded by any check measuring equipment if registering accurately;

(ii) Correcting the error if the percentage of error is ascertainable by calibration, test, or mathematical calculation; or

(iii) Using deliveries under similar conditions during a period when the equipment was registering accurately.

No adjustment will be made for inaccuracies unless they exceed the greater of (i) 1.0 percent of affected volumes, or (ii) 100 Mcf per month.

D.7 Meter Records. The parties will preserve for a period of at least two years all test data, charts, and similar measurement records. The parties will raise metering questions as soon as practicable after the time of production. No party will have any obligation to preserve metering records for more than two years except to the extent that a metering question has been raised in writing and remains unresolved.

E. DETERMINATION OF GAS COMPOSITION, GRAVITY, AND HEATING VALUE

Processor will obtain a representative samples of Supplier's gas delivered at each Delivery Point using on-line chromatography. By chromatography or other accepted method in the industry, Processor will determine the composition, gravity, and gross heating value of the hydrocarbon components of Supplier's gas in Btu per cubic foot on a dry basis at standard conditions, then adjust the result for the water vapor content of the gas (by either the volume or Btu content method) using an industry accepted practice. No heating value will be credited for Btus in H_2S or other non-hydrocarbon components. Processor will make the first determination of Btu content for Supplier's deliveries within a reasonable time after deliveries of gas begin.

F. QUALITY OF GAS

F.1 Quality Specifications. The gas delivered and redelivered shall be merchantable natural gas, at all times complying with the following quality requirements. The gas shall be commercially free of crude oil, water in the liquid phase, brine, air, dust, gums, gum-forming constituents, bacteria, and other objectionable liquids and solids, and not contain more than:

(a) 7 pounds of water vapor per MMcf.

(b) 1 grain of H_2S per 100 cubic feet.

(c) Five grains of total sulfur per 100 cubic feet.

(d) 3 mole percent of carbon dioxide (CO_2).

(e) 3 mole percent of nitrogen.

(f) 20 parts per million by volume of oxygen.

Redelivered gas shall:

(g) Not exceed 120° F. in temperature at the Delivery Point.

(h) Have a total heating value no greater than 1100 Btu per cubic foot.

(i) If a third party pipeline receiving the gas delivered has more stringent quality specifications than those stated above, the gas shall conform to the more stringent pipeline quality standard.

F.2 <u>NGLs Quality Specifications</u>. The NGLs delivered at the Plant shall be merchantable, at all times complying with the following quality requirements. The NGLs shall be commercially free of air, dust, gums, gum-forming constituents, bacteria, and other objectionable liquids and solids, and not contain more than:

(a) 1,000 ppm of total stream of carbon dioxide (CO_2).

(b) 0.5 LV ("liquid volume") % of the total components excluding N_2 and CO_2, and 1.5 LV% of the ethane.

(c) 55 LV% of ethane.

(d) 10 LV% of the C_5+ of aromatics.

(e) 0.5 LV% of the total stream of olefins; C_4 olefin maximum is 0.1 LV% of the nC_4.

(f) 600 psig vapor pressure at 100° F.

(g) 150 ppm total sulfur; pass ASTM D-2420 or D-5623 for H_2S; maximum 15 ppm of carbonyl sulfide in contained propane.

(h) 375° F. distillation end point at 14.7 psia for the portion of the mixture having a boiling point ^{3} 70° F.

(i) +27 Saybolt number for color, per ASTM D-156.

(j) No free water at 34° F. per inspection.

(k) 1 ppm of Halides including fluorides in nC_4.

(l) 110° F. temperature.

If a third party pipeline receiving the NGLs delivered has more stringent quality specifications than those stated above, the NGLs shall conform to the more stringent NGL pipeline quality standard.

F.2 <u>Quality Tests</u>. Processor will make determinations of conformity of the gas with the above specifications using procedures generally accepted in the gas industry as often as Processor reasonably deems necessary. If in Supplier's judgment the result of any test or determination is inaccurate, Processor upon request will again conduct the questioned test or determination. Supplier will bear the costs of the additional test or determination unless it shows the original test or determination to have been materially inaccurate.

F.3 <u>Separation Equipment</u>. Supplier will install condensate receiving and stabilization equipment immediately upstream of the Delivery Points.

F.4 <u>Rights as to Off Specification Gas</u>.

If any of the gas delivered by Supplier fails to meet the quality specifications stated in this Section, Processor may at its option accept delivery of the gas or discontinue or curtail taking of gas at any Delivery Point whenever its quality does not conform to the quality specifications. If Processor accepts delivery of off specification gas from Supplier or incurs costs relating to inferior gas quality in its gathering system, Processor may charge or deduct from the proceeds otherwise payable a reasonable fee for monitoring the gas quality and treating and handling the gas. Processor typically adjusts gas quality deduction levels annually, but may do so more often if needed.

G. BILLING AND PAYMENT

G.1 <u>Statement and Payment Date</u>. Processor will render to Supplier on or before the last Day of each month a statement showing for the preceding month:

(a) the volumes of gas delivered by Supplier,

(b) Supplier's MMBtu quantities of Residue Gas,

(c) Supplier's NGL gallons by component,

(d) the status of the cumulative imbalance between Supplier's or its nominees' taking in kind of Supplier's allocable Residue Gas and NGLs, if any, and

(e) any quality fees due to Processor.

Supplier's payment to Processor will be due within 10 Days of issuance of the statement as to all gas delivered during the preceding month. As between the parties, late payments and recoupments or refunds from Supplier will carry simple interest at the lower of (a) the prime rate posted at noon on the first Day of the month in which the delinquency occurs by J.P. Morgan Chase & Co., New York, New York, plus 1%, per annum or (b) the maximum lawful interest rate; provided that no interest will accrue as to monthly principal amounts of less than $1,000 due for less than one year when paid. The parties waive any rights to differing interest rates. Except as limited in Section G.2 below, Processor may recover any overpayments or collect any amounts due from Supplier to Processor for any reason at any time under this or other transactions by deducting them from any proceeds payable to Supplier or its Affiliates.

G.2 <u>Audit Rights; Time Limit to Assert Claims</u>.

(a) Each party will have the right during reasonable business hours to examine the books, records and charts of the other party to the extent necessary to verify performance of this Contract and the accuracy of any statement, charge, or computation upon execution of a reasonable confidentiality agreement. If any audit examination or review of the party's own records reveals an inaccuracy in any payment, Processor will promptly make the appropriate adjustment.

(b) No adjustment for any billing or payment shall be made, and payments shall be final after the lapse of <u>two years</u> from their due date except as to matters that either party has noted in a specific written objection to the other party in writing during the two year period, unless within the two year period Processor has made the appropriate correction. However, Supplier's responsibilities for severance taxes and third party liabilities and related interest are not affected by this subsection.

(c) No party will have any right to recoup or recover prior overpayments or underpayments that result from errors that occur in spite of good faith performance if the amounts involved do not exceed $10/month/meter. Either party may require prospective correction of such errors.

G.3 Lack of Payment; Creditworthiness.

(a) If Supplier is in arrears in its payments, or is otherwise in breach of this Contract, upon ten Days advance written notice Processor may suspend services under this Contract unless payment is forthcoming within the notice period. If Supplier remains in default after notice to pay or otherwise perform as to any fee or imbalance, or if Processor is insecure of Supplier's performance, without prejudice to other remedies Processor may (i) refuse to receive or deliver gas, (ii) suspend performance pending adequate assurance of payments, (iii) demand an irrevocable letter of credit, surety bond, or other reasonable security for payment, (iv) require advance payment in cash or payment on a more frequent billing cycle than monthly, (v) collect any amounts due from Supplier to Processor or its Affiliates for any reason at any time under this or other transactions by deducting them from any proceeds payable to Supplier or Affiliates of Supplier, or (vi) take other action as Processor deems reasonable under the circumstances to protect its interests.

(b) Processor may also require Supplier at any time to supply Processor credit information, including but not limited to bank references, financial statements, and names of persons with whom Processor may make reasonable inquiry into Supplier's creditworthiness and obtain adequate assurance of Supplier's solvency and ability to perform.

(c) Supplier hereby grants Processor a security interest in gas owned or controlled by Supplier in Processor's possession to secure payment of all fees and other amounts due under this Contract, and following a Supplier default. Processor may foreclose this possessory security interest in any reasonable manner. Upon request Supplier will execute a UCC-1 or similar Financing Statement suitable for recording describing this security interest and lien.

(d) If Supplier in good faith disputes the amount of any billing, Supplier shall nevertheless pay to Processor the amounts it concedes to be correct and provide Processor an explanation and documentation supporting Supplier's position regarding the disputed billing. Processor may then continue service for a reasonable time pending resolution of the dispute.

G.4 Metering Records Availability. Processor is not required to furnish gas volume records relating to electronic recording devices other than daily volume information except to the extent that there are indications the meter was not operating properly.

H. FORCE MAJEURE

H.1 Suspension of Performance. Unless otherwise specifically provided for in this Contract, if either party is rendered unable, wholly or in part, by Force Majeure to carry out its obligations under this Contract, other than to make payments due, the obligations of that party, so far as they are affected by Force Majeure, will be suspended during the continuance of any inability so caused, but for no longer period.

H.2 Force Majeure Definition. "Force Majeure" means acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, storms, floods, washouts, arrests and restraints of governments and people, civil disturbances, fires, explosions, breakage or accidents to machinery or lines of pipe, freezing of wells or lines of pipe, partial or entire failure of wells or sources of supply of gas, inability to obtain at reasonable cost servitudes, right of way grants, permits, governmental approvals or licenses, inability to obtain at reasonable cost materials or supplies for constructing or maintaining facilities, and other causes, whether of the kind listed above or otherwise, not within the control of the party claiming suspension and which by the exercise of reasonable diligence the party is unable to prevent or overcome.

H.3 Labor Matters Exception. The settlement of strikes or lockouts will be entirely within the discretion of the party having the difficulty, and settlement of strikes, lockouts, or other labor disturbances is not required when the affected party considers it inadvisable.

I. WARRANTY OF TITLE

Supplier warrants that it has good title and processing rights to the gas delivered, free and clear of any and all liens, encumbrances, and claims, and that Supplier has good right and lawful authority to sell the same. Supplier grants to Processor the right to process Supplier's gas for extraction of NGLs and other valuable components.

J. ROYALTY AND OTHER INTERESTS

Supplier is responsible for all payments to the owners of all working interests, mineral interests, royalties, overriding royalties, bonus payments, production payments, and the like. Processor assumes no liabilities or duties to Supplier's working or mineral interest, royalty, or other interest owners under this Contract.

K. SEVERANCE AND SIMILAR TAXES

K.1 Severance and Similar Taxes Payments. Supplier shall bear and pay to taxing authorities all severance, production, excise, sales, gross receipts, occupation, and other taxes imposed upon Supplier with respect to the gas on or prior to delivery to Processor and other taxes imposed on Supplier's facilities and operations and with respect to Residue Gas and NGLs after redelivery from Processor.

K.2 Tax Responsibilities and Disbursements. Supplier shall bear, and unless otherwise required by law, will pay to taxing authorities all severance, production, excise, sales, gross receipts, occupation, and other taxes imposed upon Supplier with respect to the gas on or prior to delivery to Processor. Processor will bear and pay all taxes imposed upon Processor with respect to the gas after delivery to Processor while the gas or NGLs are in Processor's possession, including ad valorem, franchise, sales and use, and income taxes, without prejudice to its right to recover taxes and assessments imposed on its services for Supplier under Section 5 above; Processor may increase its fees to Supplier as necessary to recover any charge on the carbon or MMBtu content of Supplier's gas, whether in the form of a "cap and trade" system, tax, or other impost.

L. INDEMNIFICATION AND RESPONSIBILITY FOR INJURY OR DAMAGE

L.1 <u>Title, Royalty, and Severance Taxes</u>. SUPPLIER RELEASES AND AGREES TO DEFEND, INDEMNIFY, AND SAVE PROCESSOR, ITS AFFILIATES, AND THEIR OFFICERS, EMPLOYEES, AND AGENTS HARMLESS FROM AND AGAINST ALL CLAIMS, CAUSES OF ACTION, LIABILITIES, AND COSTS (INCLUDING REASONABLE ATTORNEYS' FEES AND COSTS OF INVESTIGATION AND DEFENSE) RELATING TO (a) SUPPLIER'S TITLE TO GAS AND GAS PROCESSING RIGHTS, (b) PAYMENTS FOR WORKING, MINERAL, ROYALTY AND OVERRIDING ROYALTY AND OTHER INTERESTS, AND (c) SALES, SEVERANCE, AND SIMILAR TAXES, THAT ARE THE RESPONSIBILITY OF SUPPLIER UNDER SECTIONS I, J, AND K ABOVE.

L.2 <u>Responsibility for Injury or Damage</u>. As between the parties, Supplier will be in control and possession of the gas deliverable hereunder and responsible for any injury or damage relating to handling or delivery of gas until the gas has been delivered to Processor at the Delivery Points; after delivery, Processor will be deemed to be in exclusive control and possession and responsible for any injury or damage relating to handling or gathering of gas. THE PARTY HAVING RESPONSIBILITY UNDER THE PRECEDING SENTENCE SHALL RELEASE, DEFEND, INDEMNIFY, AND HOLD THE OTHER PARTY, ITS AFFILIATES, AND THEIR OFFICERS, EMPLOYEES, AND AGENTS HARMLESS FROM AND AGAINST ALL CLAIMS, CAUSES OF ACTION, LIABILITIES, AND COSTS (INCLUDING REASONABLE ATTORNEYS' FEES AND COSTS OF INVESTIGATION AND DEFENSE) ARISING FROM ACTUAL AND ALLEGED LOSS OF GAS, PERSONAL INJURY, DEATH, AND DAMAGE FOR WHICH THE PARTY IS RESPONSIBLE UNDER THIS SECTION; PROVIDED THAT NEITHER PARTY WILL BE INDEMNIFIED FOR ITS OWN NEGLIGENCE OR THAT OF ITS AGENTS, SERVANTS, OR EMPLOYEES.

M. RIGHT OF WAY

Insofar as Supplier's lease or leases permit and insofar as Supplier or its lease operator may have any rights however derived (whether from an oil and gas lease, easement, governmental agency order, regulation, statute, or otherwise), Supplier grants to Processor and Processor's gas gathering contractor, if any, and their assignees the right of free entry and the right to lay and maintain pipelines, meters, and any equipment on the lands or leases subject to this Contract as reasonably necessary in connection with the purchase or handling of Supplier's gas. All pipelines, meters, and other equipment placed by Processor or Processor's contractors on the lands and leases will remain the property of the owner and may be removed by the owner at any time consistent with its obligations under this Contract. Without limitation, Processor or its gathering contractor may disconnect and remove measurement and other facilities from any Delivery Point due to low volume, quality, term expiration, or other cause consistent with performance of Processor's obligations under this Contract.

N. ASSIGNMENT

N.1 <u>Binding on Assignees</u>. Neither party may assign this Contract nor any of the rights, interests or obligations under this Contract without the prior written consent of the other party, which shall not be unreasonably withheld. This Contract is binding upon and inures to the benefit of the successors, assigns, and representatives in bankruptcy of the parties, and, subject to any prior dedications by the assignee, shall be binding upon any purchaser of Processor's Facilities and upon any assignee or successor of Supplier. Nothing contained in this Section will prevent either party from mortgaging its rights as security for its indebtedness, but security is subordinate to the parties' rights and obligations under this Contract.

N.2 <u>Notice of Assignment</u>. No transfer of or succession to the interest of Supplier, however made, will bind Processor unless and until the original instrument or other proper proof that the claimant is legally entitled to an interest has been furnished to Processor at its Division Order address noted in the Notices Section or subsequent address.

O. MISCELLANEOUS PROVISIONS

O.1 <u>Governing Law</u>. THIS CONTRACT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF TEXAS, without reference to those that might refer to the laws of another jurisdiction.

O.2 <u>Processor's Facilities</u>. Processor's services using its Facilities hereunder is and will be considered gas gathering and processing services, and the Processor Facilities used to perform this Contract will be classified as non-utility exempt gas gathering and processing facilities.

O.3 Default and Nonwaiver. A waiver by a party of any one or more defaults by the other in the performance of any provisions of this Contract will not operate as a waiver of any future default or defaults, whether of a like or different character.

O.4 Counterparts. This Contract may be executed in any number of counterparts, all of which will be considered together as one instrument, and this Contract will be binding upon all parties executing it, whether or not executed by all parties owning an interest in the producing sources affected by this Contract. Signed copies of this Contract and facsimiles of it shall have the same force and effect as originals.

O.5 Negotiations; Entire Agreement; Amendment; No Third Party Beneficiaries. The language of this Contract shall not be construed in favor of or against either party, but shall be construed as if the language were drafted mutually by both parties. This Contract constitutes the final and complete agreement between the parties. There are no oral promises, prior agreements, understandings, obligations, warranties, or representations between the parties relating to this Contract other than those stated herein. All waivers, modifications, amendments, and changes to this Contract shall be in writing and signed by the authorized representatives of the parties. The relations between the parties are those of independent contractors; this Contract creates no joint venture, partnership, association, other special relationship, nor any fiduciary obligations. There are no third party beneficiaries of Processor's sales contracts or of this Contract.

O.6 Ratification and Third Party Gas. Omitted.

O.7 Compliance with Laws and Regulations. This Contract is subject to all valid statutes and rules and regulations of any duly constituted federal or state authority or regulatory body having jurisdiction. Neither party will be in default as a result of compliance with laws and regulations.

O.8 Fees and Costs; Damages. If mediation or arbitration is necessary to resolve a dispute other than one arising under the indemnification obligations of this Contract, each party agrees to bear its own attorneys' fees and costs of investigation and defense, and each party waives any right to recover those fees and costs from the other party or parties.

O.9 Mutual Waiver of Certain Remedies. Except as to the parties' indemnification obligations, NEITHER PARTY SHALL BE LIABLE OR OTHERWISE RESPONSIBLE TO THE OTHER FOR CONSEQUENTIAL OR INCIDENTAL DAMAGES, FOR LOST PRODUCTION, OR FOR PUNITIVE DAMAGES AS TO ANY ACTION OR OMISSION, WHETHER CHARACTERIZED AS A CONTRACT BREACH OR TORT, THAT ARISES OUT OF OR RELATES TO THIS CONTRACT OR ITS PERFORMANCE OR NONPERFORMANCE.

O.10 Waiver of Trade Practices Acts. The parties intend that Supplier's rights and remedies with respect to this Contract and all related practices of the parties shall be governed by legal principles other than the Texas Deceptive Trade Practices–Consumer Protection Act, Tex. Bus. & Com. Code Ann. §17.41 et seq. ("DTPA"). THE PARTIES HEREBY WAIVE APPLICABILITY OF THE DTPA TO THIS CONTRACT AND TO ANY AND ALL DUTIES, RIGHTS, OR REMEDIES THAT MIGHT BE IMPOSED BY THE DTPA, WHETHER THEY ARE APPLIED DIRECTLY BY THE DTPA ITSELF OR INDIRECTLY IN CONNECTION WITH OTHER STATUTES; PROVIDED THAT THE PARTIES DO NOT WAIVE §17.555 OF THE DTPA. EACH PARTY WARRANTS THAT IT IS A "BUSINESS CONSUMER" FOR PURPOSES OF THE DTPA, THAT IT HAS ASSETS OF $5 MILLION OR MORE AS SHOWN IN ITS MOST RECENT FINANCIAL STATEMENTS, THAT IT HAS KNOWLEDGE AND EXPERIENCE IN FINANCIAL AND BUSINESS MATTERS THAT ENABLES IT TO EVALUATE THE MERITS AND RISKS OF THE TRANSACTIONS CONTEMPLATED IN THIS CONTRACT, THAT IT HAS BEEN REPRESENTED BY LEGAL COUNSEL OF ITS OWN CHOICE IN ENTERING INTO THIS CONTRACT AND THE TRANSACTIONS CONTEMPLATED IN IT; AND THAT IT IS NOT IN A SIGNIFICANTLY DISPARATE BARGAINING POSITION WITH THE OTHER PARTY. Each party recognizes that the consideration for which the other party has agreed to perform under this Contract has been predicated upon the inapplicability of the DTPA and this waiver of the DTPA. Each party further recognizes that the other party, in determining to proceed with entering into this Contract, has expressly relied upon this waiver and the inapplicability of the DTPA.

O.11 Arbitration. The parties desire to resolve any disputes that may arise informally, if possible. All disputes arising out of or relating to this Contract that are not resolved by agreement of the parties must be resolved using the provisions of this Section. If a dispute or disputes arise out of or relating to this Contract, a party shall give written notice of the disputes to the other involved parties, and each party will appoint an employee to negotiate with the other party concerning the disputes. If the disputes have not been resolved by negotiation within 30 Days of the initial dispute notice, or if the complaining party fails to send an initial dispute notice, the disputes shall be resolved by arbitration in accordance with the then current International Institute for Conflict Prevention and Resolution Rules for Non-Administered Arbitration and related commentary ("Rules") and this Section. The arbitration shall be governed by the Federal Arbitration Act, 9 U.S.C. §§ 1, et seq., and the Rules, to the exclusion of any provision of state law inconsistent with them. The party seeking resolution shall initiate arbitration by written notice sent to the other party or parties to be involved. The parties shall promptly select one disinterested arbitrator with at least ten years' experience in the natural gas industry or ten years' experience with natural gas law, and not previously employed by either party or its Affiliates, and, if possible, shall be selected by agreement between the parties. If the parties cannot select an arbitrator by agreement within 30 Days of the date of the notice of arbitration, a qualified arbitrator will be selected in accordance with the Rules. If the disputes involve an amount greater than $1,000,000, they will be decided by a panel of three arbitrators with the above qualifications, one selected by each party, and the third selected by the party-appointed arbitrators, or in the absence of their agreement, pursuant to the Rules. The arbitrator(s) shall resolve the disputes and render a final award in accordance with the substantive law of the state referenced in Section O.1 above, "Governing Law." The arbitration award will be limited by Sections O.8, "Fees and Costs; Damages," O.9, "Mutual Waiver of Certain Remedies," and O.10, "Waiver of Trade Practices Acts." The parties intend case specific dispute resolution; either party may opt out of any attempted class action for all claims of any party related to this Contract. The arbitrator(s) shall state the reasons for the award in writing, and judgment on the arbitration award may be entered in any court having jurisdiction.

END OF EXHIBIT A TO GAS PROCESSING CONTRACT

EXHIBIT B
To GAS PROCESSING CONTRACT
Between DCP MIDSTREAM, LP as Supplier and
DCP MIDSTREAM PARTNERS, LP as Processor
Dated as of August 1, 2011

PROCESSING FEE ADJUSTMENTS
($ in Millions)

Plant Cost	Demand	Throughput
	Per Mcf	
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]
[***]	[***]	[***]

The capital expenditure amount results and resulting processing fee adjustments will be based on the nearest $1 million of capital expenditures.

If Plant cost is less than $[***] or exceeds $[***], the demand and throughput fees will be increased proportionately to the adjustments set forth in this Exhibit B.

END OF EXHIBIT B TO
GAS PROCESSING CONTRACT

EXHIBIT C-1
To GAS PROCESSING CONTRACT
Between DCP MIDSTREAM, LP as Supplier and
DCP MIDSTREAM PARTNERS, LP as Processor
Dated as of August 1, 2011

DELIVERY POINTS
Jackson County, Texas

No.	Processor's Meter No.	NAME	LOCATION
1.		Trunkline Gas Company, LP	Eagle Plant Inlet
2.		Supplier	Eagle Plant Inlet

EXHIBITS C-2 and C-3
To GAS PROCESSING CONTRACT
Between DCP MIDSTREAM, LP as Supplier and
DCP MIDSTREAM PARTNERS, LP as Processor
Dated as of August 1, 2011

Exhibit C-2

REDELIVERY POINTS—GAS
Jackson County, Texas

No.	Pipeline	Location	Meter #
1.	Trunkline Gas Company, LP	Eagle Plant	

Exhibit C-3

REDELIVERY POINTS—NGLs
Jackson County, Texas

No.	Pipeline	Location	Meter #
1.	DCP Sandhills Pipeline, LLC	Eagle Plant	
2.	Wilbreeze	Eagle Plant	

EXHIBIT D
To GAS PROCESSING CONTRACT
Between DCP MIDSTREAM, LP as Supplier and
DCP MIDSTREAM PARTNERS, LP as Processor
Dated as of August 1, 2011

PLANT DESIGN SPECIFICATIONS

- One 1500 barrel NGL storage tank
- Amine treater designed with 40% MDEA, 5% piperazine, 650 GPM with RTO on vent
- 40 gpm TEG system with sreconcentrator overhead condenser and vapor recovery.
- Molecular sieve designed for 200 MMscfd, partially water saturated gas
- TRCo Cryo Plant Gas Sub-cooled Process (GSP) Design with Propane Refrigeration
  - Ethane Recovery and Ethane Rejection (about 22% recovery) Design
  - 1.5 Hours NGL Storage
- Five (5) - 3616 Cat Engines with Ariel KBZ frames, two (2) single-stage inlet machines, three (3) two-stage residue machines, with one residue machine capable of operation as an inlet unit
- Three (3) electric driven refrigeration machines, 1500 HP, 4160V.
- Direct fired regen heater, direct fired two temperature level hot oil process heat (amine, TEG, and stabilizer), and direct fired ethane-rejection heat medium system
- Compression for 200 MMscfd, amine circulation and other pumps for 200 MMscfd.
- Plant residue delivered to a new 20” ANSI 600# residue pipeline (pipeline not in scope)
- Plant NGL delivered to a new 8” ANSI 600# NGL pipeline (pipeline is not in scope)
- Power line for 200 MMscfd NGL processing plant
- Utility systems (instrument air, starting air, drains, chemical storage, etc.)
- Plant Bypasses and Start-up Recycle Lines
- This gas processing plant is designed to process 200 MMscfd of natural gas (5.5 gpm of ethane (C2+) and heavier NGL content, 2% CO_2) delivered at 500 psig at 50 to 80°F. Design recoveries are 90% C2, 98% C3, 98.5% iC4, and 99% nC4 and C5+ with gas of this quality. The plant can also operate in ethane rejection mode with 25% C2 recovery and a guaranteed 94% C3 recovery, 98% C4s, and 99% C5+.

Exhibit 12.1

RATIO OF EARNINGS TO FIXED CHARGES

The table below sets forth the calculation of Ratios of Earnings to Fixed Charges.

	DCP Midstream Partners, LP					
	Nine Months Ended September 30,	Year Ended December 31,				
	2011	2010	2009	2008	2007	2006
		(Millions)				
Earnings from continuing operations before fixed charges						
Pretax income (loss) from continuing operations before earnings from unconsolidated affiliates	$ 73.7	$ 24.5	$ (37.0)	$ 124.3	$ (25.0)	$ 58.4
Fixed charges	26.1	29.9	30.3	33.6	27.0	12.6
Amortization of capitalized interest	0.1	0.1	0.1	0.1	—	—
Distributed earnings from unconsolidated affiliates	28.6	28.9	26.9	29.6	35.8	25.9
Less:						
Capitalized interest	(0.7)	(0.2)	(1.3)	(0.3)	(0.2)	(0.4)
Earnings from continuing operations before fixed charges	$ 127.8	$ 83.2	$ 19.0	$ 187.3	$ 37.6	$ 96.5
Fixed charges						
Interest expense, net of capitalized interest	$ 24.6	$ 28.8	$ 28.3	$ 32.6	$ 26.0	$ 11.4
Capitalized interest	0.7	0.2	1.3	0.3	0.2	0.4
Estimate of interest within rental expense	0.3	0.6	0.5	0.5	0.6	0.7
Amortization of deferred loan costs	0.5	0.3	0.2	0.2	0.2	0.1
Total fixed charges	$ 26.1	$ 29.9	$ 30.3	$ 33.6	$ 27.0	$ 12.6
Ratio of earnings to fixed charges	4.90	2.78	0.63	5.57	1.39	7.66

For purposes of determining the ratio of earnings to fixed charges, earnings are defined as pretax income or loss from continuing operations before earnings from unconsolidated affiliates, plus fixed charges, plus distributed earnings from unconsolidated affiliates, less capitalized interest. Fixed charges consist of interest expensed, capitalized interest, amortization of deferred loan costs, and an estimate of the interest within rental expense.

Exhibit 31.1

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

I, Mark A. Borer, certify that:

1. I have reviewed this quarterly report on Form 10-Q of DCP Midstream Partners, LP for the three and nine months ended September 30, 2011;

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

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

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

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

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

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

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

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

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

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

Date: November 9, 2011

/s/ Mark A. Borer
Mark A. Borer
Chief Executive Officer

Exhibit 31.2

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

I, Angela A. Minas, certify that:

1. I have reviewed this quarterly report on Form 10-Q of DCP Midstream Partners, LP for the three and nine months ended September 30, 2011;

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

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

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

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

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

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

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

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

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

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

Date: November 9, 2011

/s/ Angela A. Minas
Angela A. Minas
Chief Financial Officer

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

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

(a) the quarterly report on Form 10-Q of the Partnership for the three and nine months ended September 30, 2011, filed on the date hereof with the Securities and Exchange Commission (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

/s/ Mark A. Borer
Mark A. Borer
Chief Executive Officer
November 9, 2011

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

Exhibit 32.2

Certification of Chief Financial Officer
Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906
of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)

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

(a) the quarterly report on Form 10-Q of the Partnership for the three and nine months ended September 30, 2011, filed on the date hereof with the Securities and Exchange Commission (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

/s/ Angela A. Minas
Angela A. Minas
Chief Financial Officer
November 9, 2011

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