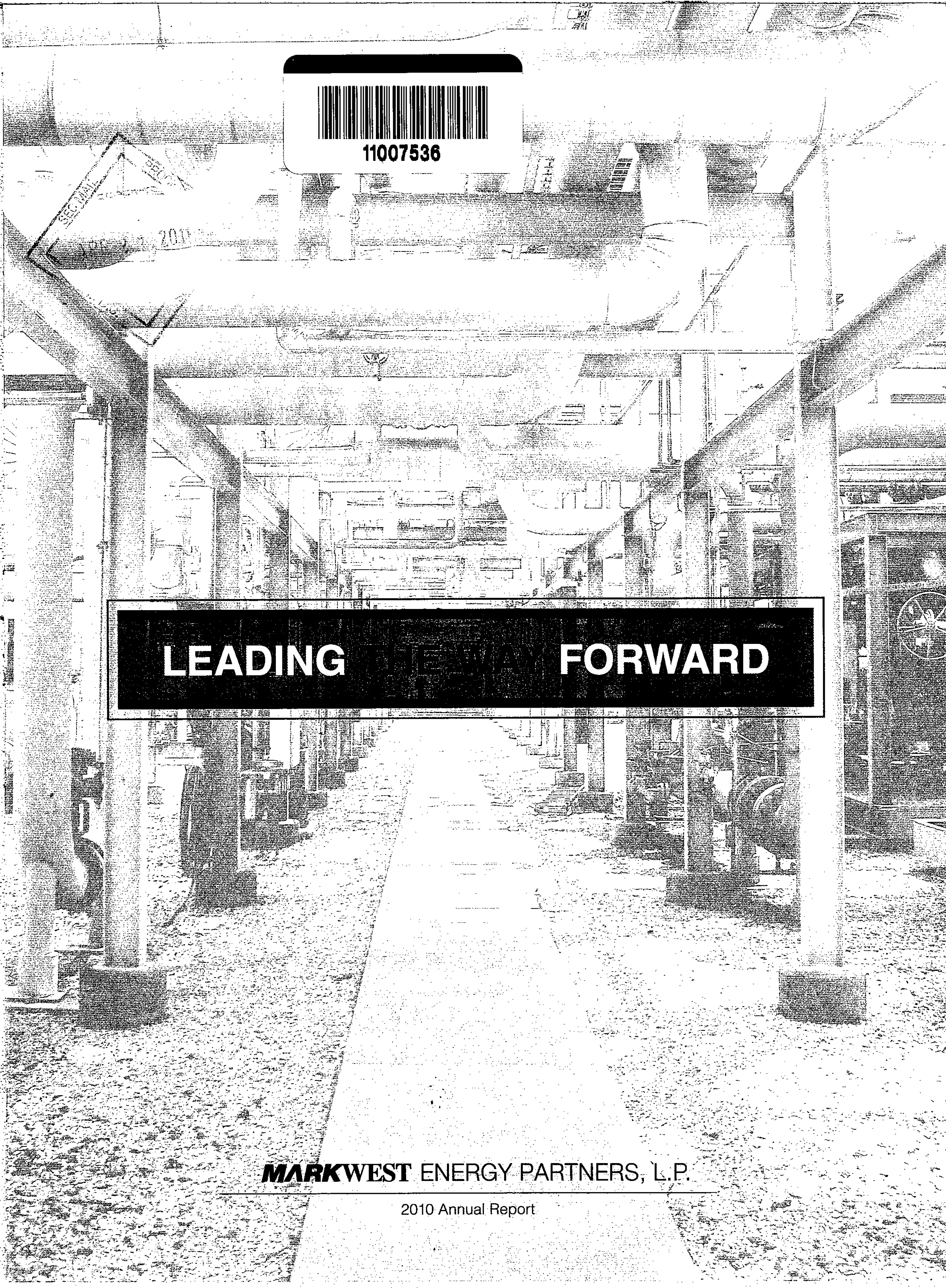
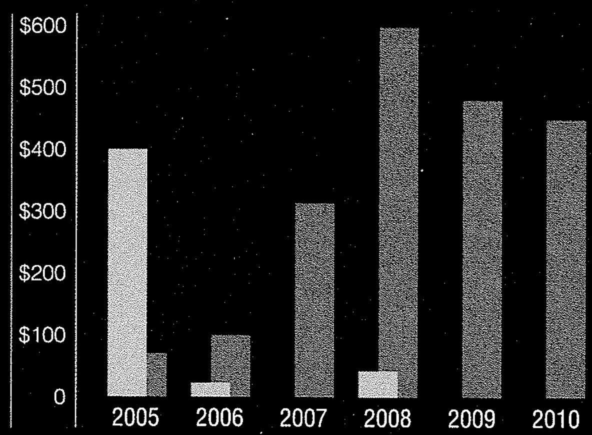


LEADING THE WAY FORWARD

MARKWEST ENERGY PARTNERS, L.P.

2010 Annual Report

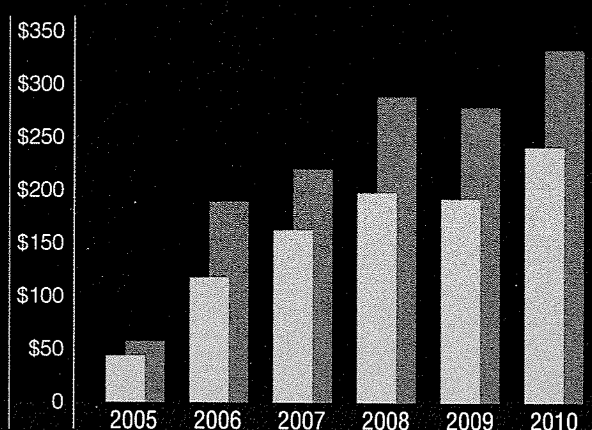


Growth Capital Expenditures

($ in millions)

- Acquisitions
- Organic Growth Capital

NOTE: Numbers include growth capital that has been funded through joint ventures and divestiture activities. See footnote on page 4 of this Annual Report for additional information.

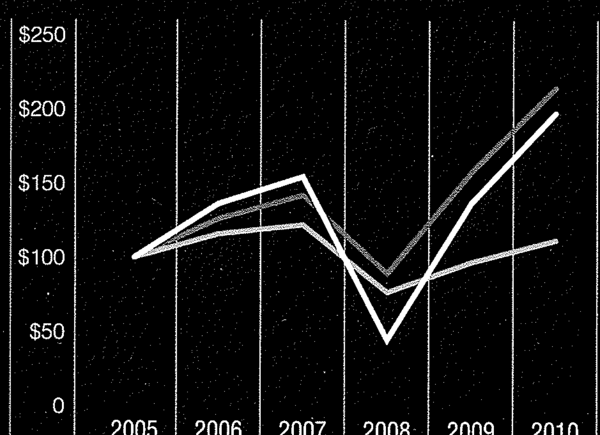


Financial Performance

($ in millions)

- Distributable Cash Flow
- Adjusted EBITDA

NOTE: See footnote on page 4 of this Annual Report for important disclosures regarding these non-GAAP financial measures.



Performance Graph

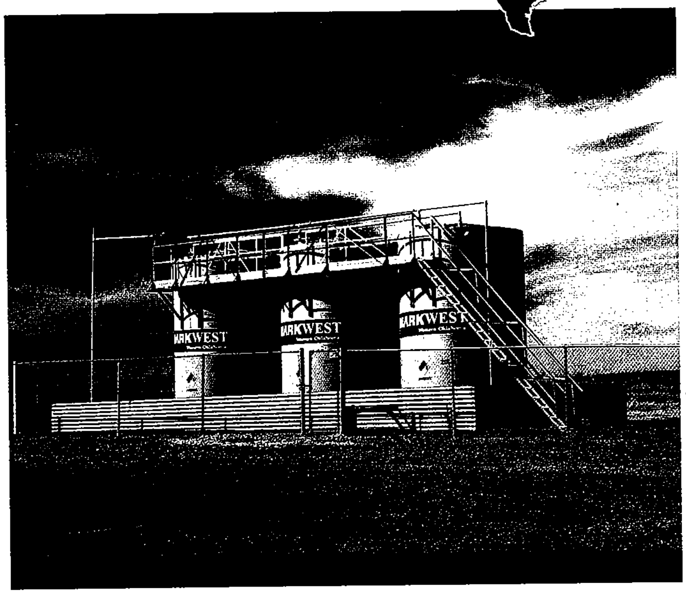
(assumes $100 invested on 12/31/05)

- MarkWest Energy Partners, L.P.
- S&P 500 Total Return Index
- Alerian MLP Total Return Index

Source: Bloomberg

Disclaimer: The statements contained in this Annual Report contain "forward-looking statements" within the meaning of the Securities Act of 1933 and the Securities Exchange Act of 1934, each as amended. These forward-looking statements (which in many instances can be identified by words like "may," "will," "should," "expects," "plans," "believes," and other comparable words) are based on the Partnership's current expectations and beliefs concerning future developments and their potential effects on the Partnership, but are not guarantees of future performance and involve risks and uncertainties. You are urged to carefully review and consider the cautionary statements and other disclosures made in the Partnership's enclosed Annual Report on Form 10-K for fiscal year 2010, including under the heading "Risk Factors," which identify and discuss significant risks, uncertainties, and various other factors that could cause actual results to vary significantly from those expected or implied in the forward-looking statements.

Southwest



In the Southwest Segment, we gather, process, treat, and transport natural gas and natural gas liquids (NGL) in East Texas, Southeast Oklahoma, Western Oklahoma, and several smaller systems throughout the Southwest. Our assets in the Southwest include 16 natural gas gathering systems, seven natural gas processing/treating plants, three intrastate gas pipelines, and two interstate gas pipelines.

Areas of Operation
Oklahoma, Texas, New Mexico, Louisiana, and Mississippi

Resource Plays
Woodford Shale, Granite Wash, Haynesville Shale, Anadarko Basin; and the Cotton Valley, Travis Peak, and Pettit Formations

Gathering
1.6 billion cubic feet per day (Bcf/d) gathering capacity

Processing
580 million cubic feet per day (MMcf/d) processing capacity

Transportation
1.5 Bcf/d of transportation capacity, including the Arkoma Connector Pipeline joint venture with ArcLight Capital Partners

UNDER CONSTRUCTION
Processing
60 MMcf/d cryogenic processing capacity at our Arapaho complex near Elk City, Oklahoma

Transportation
75 MMcf/d expansion of the pipeline connecting our Granite Wash system with our Arapaho complex

Northeast

We are the largest processor and fractionator of natural gas and NGLs in the Appalachian region. In addition to natural gas processing and fractionation, and NGL transportation, storage, and marketing in Appalachia, we also operate a crude oil transportation pipeline in Michigan. Our Appalachian assets include five natural gas processing plants and one fractionation and storage facility.

Areas of Operation
Kentucky, West Virginia, and Michigan

Resource Plays
Appalachian Basin, Huron/Berea Shale, and the Niagaran Reef

Processing
505 MMcf/d processing capacity

Fractionation
24,000 barrels per day (Bbl/d) NGL fractionator at our Siloam complex in South Shore, Kentucky

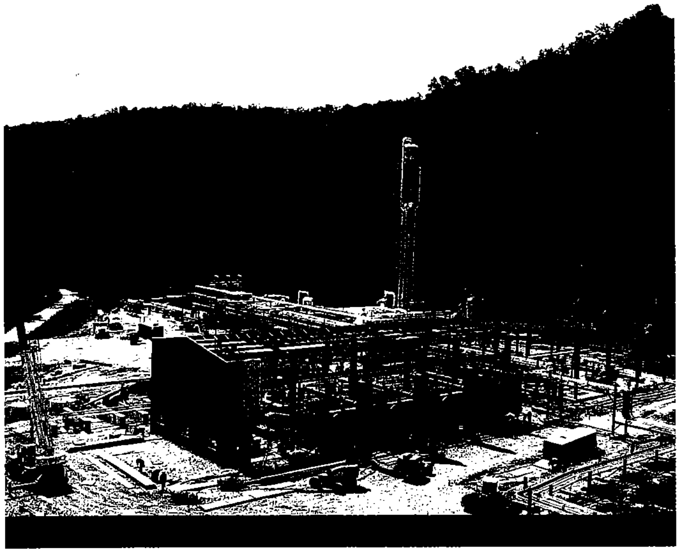
Storage
260,000-barrel propane storage capacity

Other
NGL marketing by truck, rail, and barge

UNDER CONSTRUCTION
Processing
60 MMcf/d cryogenic processing capacity at our Langley, Kentucky complex

Transportation
Complete 8-inch NGL pipeline connecting our Langley complex to the Siloam fractionator

Liberty



The Liberty Segment represents our joint venture with The Energy & Minerals Group, which provides natural gas midstream services in the liquids-rich areas of the Marcellus Shale. We are the largest processor of natural gas in the Marcellus, with fully integrated processing, fractionation, storage, and marketing operations that are critical to the development of the Marcellus.

Areas of Operation
Southwest Pennsylvania and Northern West Virginia

Resource Play
Marcellus Shale

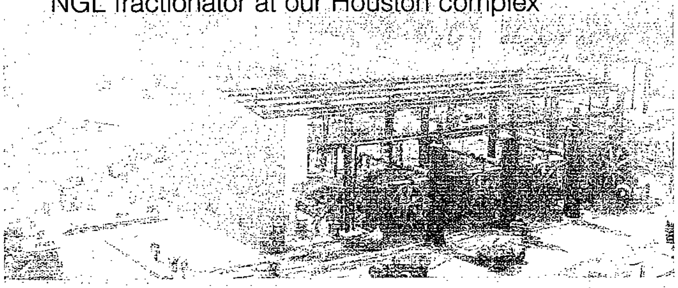
Gathering
250 MMcf/d gathering capacity

Processing
290 MMcf/d cryogenic processing capacity

Fractionation
27,000 Bbl/d depropanizer (partial fractionation)

UNDER CONSTRUCTION
Processing
455 MMcf/d cryogenic processing capacity at our Houston, Majorsville, and Mobley complexes

Fractionation
Complete remaining portion of 60,000 Bbl/d NGL fractionator at our Houston complex



Gulf Coast

The Gulf Coast Segment consists of the Javelina gas processing and fractionation facility in Corpus Christi, Texas. Javelina treats, processes, and fractionates off-gas from six local crude oil refineries.

Area of Operation
Corpus Christi, Texas

Processing
140 MMcf/d processing capacity

Fractionation
29,000 Bbl/d NGL fractionation capacity

Other
NGL marketing and transportation, including ethane, ethylene, propane, propylene, isobutane, normal butane, butylenes, and pentanes

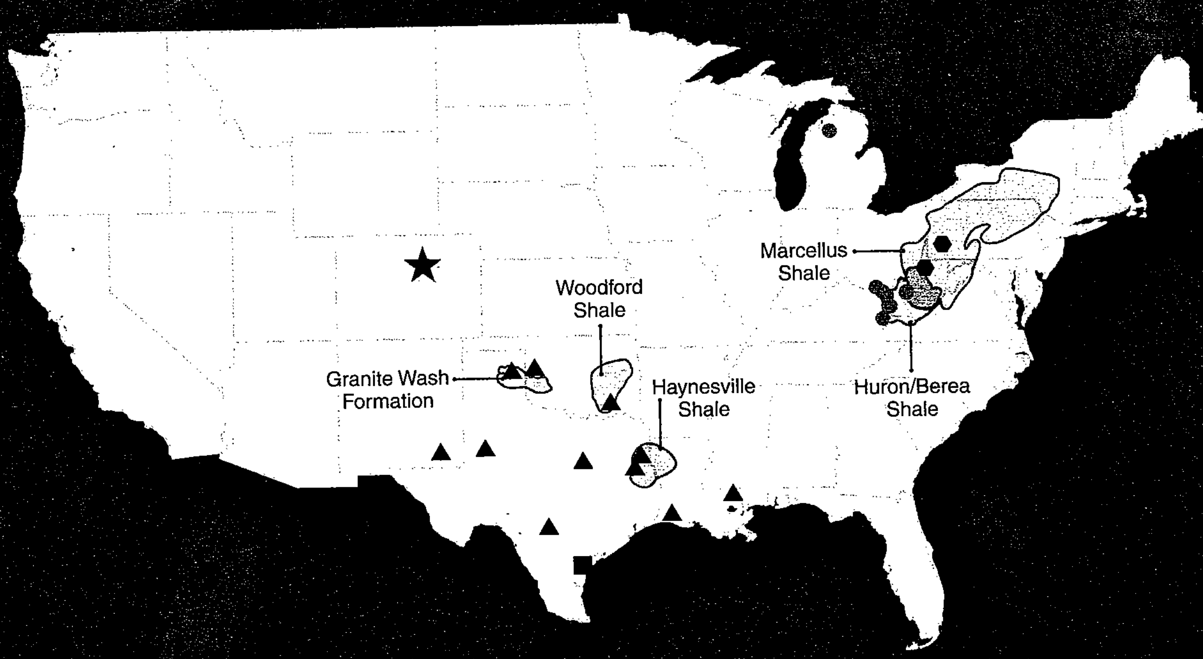
High-purity hydrogen production

Net Operating Margin* by Segment

54%	20%	13%	13%
Southwest	Northeast	Liberty	Gulf Coast

*Net Operating Margin is a non-GAAP financial measure. Please read "Business—Our Contracts" in Item 1 of the enclosed Annual Report on Form 10-K for further discussion and reconciliation of this financial measure.

AREAS OF OPERATION



Southwest Northeast Liberty Gulf Coast Corporate Office

2010 was another strong year for MarkWest, with record financial results, solid operating performance, and continued expansion in our key operating areas.

The natural gas resource plays in which we operate are expected to represent a significant portion of the future natural gas supply for the United States. Due to the quality of the plays and the utilization of efficient and productive drilling technologies by our producer customers, we believe these plays will provide significant long-term growth opportunities for MarkWest.

In 2010, we generated record distributable cash flow of $241 million and Adjusted EBITDA of $333 million, and we ended the year in a very strong financial position. We have a consistent and conservative approach to managing our balance sheet, and since the beginning of 2010 we have raised more than $1 billion in capital to support our growth projects in emerging resource plays and to provide increased financial flexibility.

In addition, we received upgrades from the rating agencies in 2010 as a result of our financial performance and consistent improvement in our credit metrics. Our cost of capital continues to come down, we have significantly extended the maturity of our debt, and we continued to fund our capital requirements well in advance. Overall, we are very pleased with our 2010 financial results, including a strong full-year distribution coverage ratio of 1.30 and the growth in our common unit distributions, reflecting our long-term objective of delivering sustainable, top-quartile total returns for our unitholders.

One of our long-term financial objectives is to further increase our fee-based net operating margin, which we forecast will increase from approximately 40 percent in 2010 to approximately 50 percent in 2012. For the portion of our business that is not fee-based, we continue to execute a rolling 36-month hedging program to manage the risk associated with commodity price exposure. Currently, approximately 70 percent, 60 percent, and 40 percent of our commodity positions are hedged in 2011, 2012, and 2013, respectively. A disciplined hedge program is a key part of our long-term success, and we will continue to execute a range of hedge transactions to lock in strong margins and to secure a large percentage of the commodity-sensitive portion of our future distributable cash flow.

Our operational focus is to provide high-quality midstream services and to expand our presence in liquids-rich resource plays that provide superior economics for MarkWest and our producer customers. We have been executing this strategy for several years, and our operational performance in 2010 demonstrates that this strategy continues to be very successful.

Our Western Oklahoma operating area includes our Foss Lake system serving the Anadarko Basin and our Stiles Ranch system serving the Granite Wash formation in the Texas Panhandle. Both gathered volumes and natural gas liquids (NGL) sales in Western Oklahoma increased in 2010. The Granite Wash continues to be one of the most economic plays in the United States for our producer customers, and as a result of the tremendous growth from the liquids-rich zones of the Granite Wash, we have seen a significant increase in the percentage of rich-gas volumes that we gather and process. Consequently, in early 2011 we announced the expansion of our gathering system and Arapaho processing complex in Western Oklahoma, which is scheduled to come online in the second half of 2011. MarkWest has been a premier midstream service provider in Western Oklahoma for nearly a decade and is ideally positioned to continue supporting the increasing production from the Granite Wash and surrounding areas.

$241 million

Record Distributable Cash Flow in 2010

In Southeast Oklahoma, our Woodford Shale gathering volumes grew approximately 25 percent in 2010. The Woodford Shale has been a significant growth story for MarkWest, and while the Woodford still has tremendous potential for growth, much of the gas is dry, and in the current commodity pricing environment we expect to see a modest decline in Woodford volumes in 2011. However, a portion of the Woodford produces liquids-rich gas, and we expect Newfield and other producers to continue to prioritize their drilling resources on these liquids-rich areas, which are more profitable for MarkWest and our producers. The Woodford Shale is a very productive resource play, and we believe it will continue to contribute to our fee-based revenues for many years.

In our Carthage system in East Texas, we gather natural gas from the Cotton Valley, Travis Peak, and Pettit formations, as well as the Haynesville Shale. East Texas gathering volumes and NGL sales were relatively flat in 2010. In the near term, we believe the increased production from the Haynesville development will continue to largely offset the declines in Cotton Valley and Travis Peak production. Over the longer term, we believe tremendous potential remains for additional drilling in the Cotton Valley and Travis Peak when natural gas prices return to the mid $5 range and above.

Our Javelina off-gas processing and fractionation plant in Corpus Christi, Texas, continues to be a solid performer both operationally and financially. Processed volumes and fractionated barrels were virtually flat in 2010, while segment operating income increased by nearly 25 percent, primarily as a result of strong purity product prices. Javelina continues to be a key part of our operations and provides important diversity and stability to our cash flow.

In the Northeast Segment, which includes five processing facilities in Kentucky and West Virginia as well as our Siloam fractionation and marketing complex, gas processing volumes were relatively flat in 2010, while NGL sales volumes increased year-over-year. We continue to fractionate record volumes at the

Siloam fractionator, driven by growing NGL deliveries from EQT Corporation's Huron Shale operations and from the significant volume growth of butane and heavier NGLs from our Marcellus operations. Our Siloam facility will continue to fractionate the heavier NGLs from our Marcellus operations until our Houston, Pennsylvania, fractionator comes online in the second half of 2011.

In early 2011, we significantly enhanced our strategic position in the Northeast with the acquisition of EQT's Langley processing complex in southeastern Kentucky and the Ranger NGL pipeline, which will connect Langley with Siloam in early 2012. We have a long-standing relationship with EQT, and this transaction solidifies the relationship for many years to come. The sale allowed EQT to raise additional capital to support its Huron and Marcellus development programs, which we believe will provide incremental processing and fractionation volumes to MarkWest. For MarkWest, the EQT acquisition was very strategic and immediately accretive, and provides long-term value for our unitholders. We have been the leading processor and fractionator in the Northeast for more than 20 years, and the EQT acquisition further strengthens our significant competitive position in West Virginia and Kentucky.

deliver ethane to multiple markets including the premium Gulf Coast market, rapidly evolving international markets, and potential future ethane crackers in the Northeast. Ethane recovery has been a key focus for us as we design and build our processing plants and NGL pipeline system; and regardless of which ethane project is completed, we will play a key role in recovering, transporting, and fractionating purity ethane.

In early 2011, Liberty announced an agreement with EQT to install a 120 MMcf/d cryogenic processing plant near EQT's Logansport compressor station in Mobley, West Virginia, to process liquids-rich gas transported in EQT's Equitrans natural gas pipeline. EQT has substantial rich-gas Marcellus acreage in northern West Virginia and has contracted with MarkWest Liberty for the majority of the plant capacity. We will also extend our NGL pipeline system to transport the NGLs recovered at the plant to our Houston fractionation and marketing complex.

Looking ahead, we believe the liquids-rich shale production in Appalachia will extend from the Huron/Berea Shale in southeastern Kentucky to the Marcellus Shale in southwest Pennsylvania and northern West Virginia. MarkWest is uniquely positioned to capitalize on this growth given our existing NGL capabilities

As a result of our extensive NGL processing, fractionation, marketing, and storage capabilities in the Northeast, we are uniquely positioned to capitalize on the tremendous growth in the shale plays located throughout the region.

In the Liberty Segment—our joint venture with The Energy & Minerals Group, which is focused on the development of the Marcellus Shale in southwest Pennsylvania and northern West Virginia—2010 was a landmark year: gathered volumes nearly tripled, processed volumes quadrupled, and cash flows grew by more than three times. The Marcellus continues to prove itself to be one of the most economic and prolific basins in the United States; and we continue to enjoy a strong and effective relationship with our producer customers.

Our Liberty gathering and processing systems continue to grow, and by the middle of 2011 we will have total processing capacity of 625 million cubic feet per day (MMcf/d), nearly all of which is supported by long-term contracts. By mid 2012, our processing capacity is expected to grow to nearly 750 MMcf/d.

In addition, in the second half of 2011 we will bring online the final phase of our 60,000 barrel per day fractionator at our Houston, Pennsylvania, complex to produce and market purity butanes and natural gasoline. Currently, we fractionate and market purity propane at Houston, whereas the butane and heavier NGL components are trucked to Siloam for fractionation and marketing.

Our Liberty team is also working on the development of Project Mariner, our joint effort with Sunoco Logistics to transport Marcellus ethane to premium Gulf Coast markets beginning in 2013. Project Mariner has significant advantages relative to the other announced ethane projects, including the lowest required volume commitment by the producers and the unique ability to

with multiple processing facilities, strategic downstream access, and two large fractionation, marketing, and storage complexes. Our long-term goal is to connect our two systems serving the Huron/Berea and Marcellus Shales with a fully integrated, scalable midstream solution that will significantly benefit producers in the Appalachian Basin.

In summary, 2010 was a strong year for MarkWest, both operationally and financially. With a diverse set of assets in growing resource plays and a dedicated, results-oriented team, we are very well positioned to continue developing significant midstream infrastructure and to provide outstanding midstream services to our producer customers. We believe these growth opportunities, coupled with the strength of our balance sheet, will be the foundation for sustainable distribution growth and will allow us to achieve our objective of providing long-term, top-quartile total returns for our unitholders.

Thank you for your continued support.

Frank M. Semple
Chairman, President and Chief Executive Officer

April 15, 2011

Financial and Operating Summary

SELECTED FINANCIAL DATA *($000, except per unit data)*	Years ended December 31, 2008	2009	**2010**
Revenue	$ 1,338,490	$ 738,283	**$ 1,187,631**
Net income (loss) attributable to the Partnership	$ 208,073	$ (118,668)	**$ 467**
Net income (loss) attributable to the Partnership's common unitholders per common unit			
Basic	$ 4.02	$ (1.97)	**$ (0.01)**
Diluted	$ 4.02	$ (1.97)	**$ (0.01)**
Weighted average common units outstanding			
Basic	51,013	60,957	**70,128**
Diluted	51,016	60,957	**70,128**
Cash distribution declared per common unit	$ 2.059	$ 2.560	**$ 2.560**
Other Financial Data			
Distributable cash flow*	$ 198,080	$ 192,398	**$ 241,080**
Adjusted EBITDA*	$ 289,012	$ 279,183	**$ 333,115**
Balance Sheet Data			
Working capital	$ 51,237	$ 13,536	**$ (43,296)**
Total assets	$ 2,673,054	$ 3,014,737	**$ 3,333,362**
Total long-term debt	$ 1,172,965	$ 1,170,072	**$ 1,273,434**
Total equity	$ 1,207,759	$ 1,379,393	**$ 1,536,020**

Operating Data	Years ended December 31, 2008	2009	**2010**
Southwest			
East Texas			
Gathering system throughput (Mcf/d)	442,900	454,400	**430,300**
NGL product sales (gallons)	193,534,100	245,787,000	**245,781,200**
Oklahoma			
Foss Lake gathering system throughput (Mcf/d)	95,800	86,600	**71,100**
Stiles Ranch gathering system throughput (Mcf/d)	84,800	89,300	**112,300**
Grimes gathering system throughput (Mcf/d)	12,900	9,700	**7,700**
Arapaho NGL product sales (gallons)	79,416,400	126,870,500	**134,118,600**
Southeast Oklahoma gathering systems throughput (Mcf/d)	318,700	416,800	**521,400**
Arkoma Connector Pipeline throughput (Mcf/d)	N/A	277,300	**375,900**
Other Southwest			
Appleby gathering system throughput (Mcf/d)	58,400	47,300	**31,600**
Other gathering systems throughput (Mcf/d)	11,000	10,300	**7,900**
Northeast			
Appalachia			
Natural gas processed (Mcf/d)	202,200	194,600	**188,700**
Keep-whole sales (gallons)	140,847,500	145,493,100	**136,711,200**
Percent-of-proceeds sales (gallons)	53,987,900	99,910,200	**120,255,100**
Total NGL product sales (gallons)	194,835,400	245,403,300	**256,966,300**
Michigan			
Crude oil transported for a fee (Bbl/d)	13,300	12,300	**12,800**
Liberty			
Marcellus			
Natural gas processed (Mcf/d)	18,700	51,800	**215,700**
Gathering system throughput (Mcf/d)	18,700	53,500	**142,200**
NGL product sales (gallons)	N/A	34,409,000	**119,921,400**
Gulf Coast			
Javelina			
Refinery off-gas processed (Mcf/d)	122,900	120,200	**118,600**
Liquids fractionated (Bbl/d)	24,400	23,200	**22,500**

On February 21, 2008, MarkWest Energy Partners, L.P. (Partnership) completed its plan of redemption and merger (Merger) with MarkWest Hydrocarbon, Inc. (Hydrocarbon), pursuant to which Hydrocarbon was merged into the Partnership. Since Hydrocarbon was considered the acquirer for accounting purposes, the dollar amounts for 2007 and prior in the Growth Capital Expenditures and Financial Performance graphs in this Annual Report represent the consolidated results of Hydrocarbon, with the exception of distributable cash flow (DCF) which represents the Partnership results because DCF is a measure of performance that was not applicable to Hydrocarbon. For more details about the Merger, please see Note 3 of the Notes to Consolidated Financial Statements included in Item 8 of the enclosed Annual Report on Form 10-K.

**DCF and Adjusted EBITDA are non-GAAP financial measures. The GAAP measure most directly comparable to DCF and Adjusted EBITDA is net income (loss). In general, we define DCF as net income (loss) adjusted for (i) depreciation, amortization, accretion, and other non-cash expense; (ii) amortization of deferred financing costs; (iii) loss on redemption of debt net of current tax benefit; (iv) non-cash (earnings) loss from unconsolidated affiliates; (v) distributions from (contributions to) unconsolidated affiliates (net of affiliate growth capital expenditures); (vi) non-cash compensation expense; (vii) non-cash derivative activity; (viii) losses (gains) on the disposal of property, plant, and equipment (PP&E) and unconsolidated affiliates; (ix) provision for deferred income taxes; (x) cash adjustments for non-controlling interest in consolidated subsidiaries; (xi) losses (gains) relating to other miscellaneous non-cash amounts affecting net income for the period; and (xii) maintenance capital expenditures. We define Adjusted EBITDA as net income (loss) adjusted for (i) depreciation, amortization, accretion, and other non-cash expense; (ii) interest expense; (iii) amortization of deferred financing costs; (iv) loss on redemption of debt; (v) losses (gains) on the disposal of PP&E and unconsolidated affiliates; (vi) non-cash derivative activity; (vii) non-cash compensation expense; (viii) provision for income taxes; (ix) adjustments for cash flow from unconsolidated affiliates; (x) adjustment related to non-wholly owned subsidiaries; and (xi) losses (gains) relating to other miscellaneous non-cash amounts affecting net income for the period. DCF and Adjusted EBITDA are not measures of performance calculated in accordance with GAAP and should not be considered in isolation or as a substitute for net income, income from operations, or cash flow as reflected in our financial statements. Please see the Form 8-K we filed concurrently with our 2011 Proxy Statement for our calculations of DCF and Adjusted EBITDA, along with the corresponding reconciliations to net income and management's reasons for including such financial measures in this Annual Report.*

MARKWEST ENERGY PARTNERS, L.P.

LEADING THE WAY FORWARD

2010 Annual Report on Form 10-K

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

FORM 10-K

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

For the fiscal year ended December 31, 2010

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 001-31239

MARKWEST ENERGY PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**27-0005456**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1515 Arapahoe Street, Tower 1, Suite 1600, Denver, CO 80202-2137
(Address of principal executive offices)

Registrant's telephone number, including area code: **303-925-9200**

Securities registered pursuant to Section 12(b) of the Act: **Common units representing limited partner interests, New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark whether the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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 ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

The aggregate market value of common units held by non-affiliates of the registrant on June 30, 2010 was approximately $2.3 billion. As of February 18, 2011, the number of the registrant's common units were 75,160,105.

DOCUMENTS INCORPORATED BY REFERENCE:

The information required by Part III of this Report, to the extent not set forth herein, is incorporated herein by reference from the registrant's definitive proxy statement relating to the Annual Meeting of Unitholders to be held in 2011, which definitive proxy statement shall be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this Report relates.

MarkWest Energy Partners, L.P.
Form 10-K

Table of Contents

Throughout this document we make statements that are classified as "forward-looking." Please refer to the "Forward-Looking Statements" included later in this section for an explanation of these types of assertions. Also, in this document, unless the context requires otherwise, references to "we," "us," "our," "MarkWest Energy" or the "Partnership" are intended to mean MarkWest Energy Partners, L.P., and its consolidated subsidiaries owned as of December 31, 2010. References to "MarkWest Hydrocarbon" or the "Corporation" are intended to mean MarkWest Hydrocarbon, Inc., a wholly-owned taxable subsidiary of the Partnership.

Glossary of Terms

The abbreviations, acronyms and industry technology used in this report are defined as follows.

Bbl	Barrel
Bbl/d	Barrels per day
Btu	One British thermal unit, an energy measurement
Dth/d	Dekatherms per day
EBITDA (a non-GAAP financial measure)	Earnings Before Interest, Taxes, Depreciation and Amortization
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States of America
Gal	Gallon
Gal/d	Gallons per day
LIBOR	London Interbank Offered Rate
Mcf	One thousand cubic feet of natural gas
Mcf/d	One thousand cubic feet of natural gas per day
Merger	On February 21, 2008, the Partnership completed the transactions contemplated by its plan of redemption and merger with MarkWest Hydrocarbon, Inc. and MWEP, L.L.C., a wholly-owned subsidiary of the Partnership. Refer to Note 3 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.
MMBtu	One million British thermal units, an energy measurement
MMBtu/d	One million British thermal units per day
MMcf/d	One million cubic feet of natural gas per day
Net operating margin (a non-GAAP financial measure)	Revenue, excluding any derivative gain (loss), less purchased product costs, excluding any derivative gain (loss)
NGL	Natural gas liquids, such as ethane, propane, butanes and natural gasoline
N/A	Not applicable
OTC	Over-the-Counter
SEC	Securities and Exchange Commission
TUR	Total unitholder return
WTI	West Texas Intermediate

Forward-Looking Statements

Certain statements and information included in this Annual Report on Form 10-K may constitute "forward-looking statements." The words "could," "may," "predict," "should," "expect," "hope," "continue," "potential," "plan," "intend," "anticipate," "project," "believe," "estimate," and similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. These forward-looking statements are based on current expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Important factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to, those described in (1) Item 1A. Risk Factors of this Form 10-Kand elsewhere in this report, (2) our reports and registration statements filed from time to time with the SEC and (3) other announcements we make from time to time.

PART I

ITEM 1. Business

General

MarkWest Energy Partners, L.P. is a publicly traded Delaware limited partnership formed in January 2002. We are a master limited partnership engaged in the gathering, processing and transportation of natural gas; the transportation, fractionation, storage and marketing of NGLs; and the gathering and transportation of crude oil. We conduct our operations in four geographic operating segments: Southwest, Northeast, Liberty and Gulf Coast. Maps detailing the individual assets can be found on our Internet website, *www.markwest.com*. For more information on these segments, see *Our Operating Segments* discussion below.

The following table summarizes the operating performance for each segment for the year ended December 31, 2010 (amounts in thousands). For further discussion of our segments and a reconciliation to our consolidated statement of operations, see Note 25 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

	Southwest	Northeast	Liberty	Gulf Coast	Total
Revenue	$665,768	$384,724	$105,911	$85,160	$1,241,563
Purchased product costs	308,960	252,827	16,840	—	578,627
Net operating margin(1)	356,808	131,897	89,071	85,160	662,936
Facility expenses	81,772	19,513	24,028	33,337	158,650
Portion of operating income attributable to non-controlling interests	6,440	—	26,126	—	32,566
Operating income before items not allocated to segments	$268,596	$112,384	$ 38,917	$51,823	$ 471,720

(1) Net operating margin is a non-GAAP financial measure. For a reconciliation to income from operations, the most comparable GAAP financial measure, see *Our Contracts* discussion below.

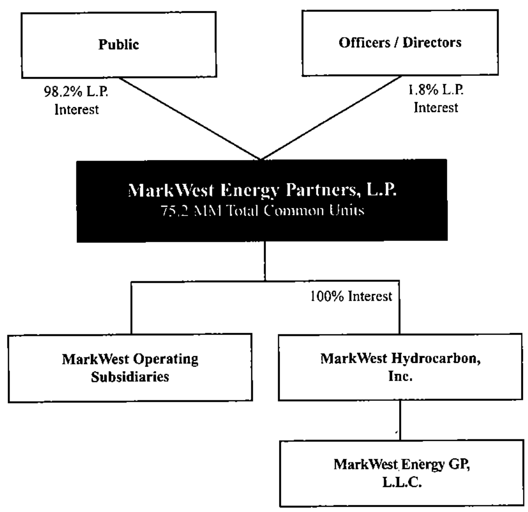
Organizational Structure

We are a master limited partnership with outstanding common units and Class A units. Our common units are publicly traded on the New York Stock Exchange. All of our Class A units are owned by the Corporation and our general partner, MarkWest Energy GP, L.L.C. (the "General

Partner"), which are our wholly-owned subsidiaries. Class A units represent limited partner interests in the Partnership and have identical rights and obligations of the Partnership common units except that Class A units (i) do not have the right to vote on, approve or disapprove, or otherwise consent to or not consent to any matter (including mergers, share exchanges and similar statutory authorizations) except as otherwise required by any non-waivable provision of law and (ii) do not share in any cash and cash equivalents on hand, income, gains, losses, deductions and credits that are derived from or attributable to the Partnership's ownership of, or sale or disposition of, the shares of MarkWest Hydrocarbon common stock. The ownership structure whereby our Class A units are held by the Corporation and the General Partner was adopted partially for tax purposes. The following table provides the aggregate number of units and relative ownership interests of the Class A units and common units as of February 18, 2011 (units in millions):

	Units	%
Class A units	22.6	23%
Common units	75.2	77%
Total units	97.8	100%

The Class A units held by MarkWest Hydrocarbon and the General Partner are not treated as outstanding common units in the accompanying Consolidated Balance Sheets. The ownership percentages as of February 18, 2011 in the graphic depicted below reflect the Partnership structure from the basis of the consolidated financial statements with the Class A units eliminated.



The primary benefit of our organizational structure is the absence of incentive distribution rights, which prior to our reorganization in February 2008, represented the General Partner's right to receive an increasing percentage of quarterly distributions of available cash after a minimum quarterly distribution and certain target distribution levels had been achieved. The absence of incentive distribution rights substantially lowers our cost of equity capital and increases the cash available to be distributed to our common unitholders. This enhances our ability to compete for new acquisitions and improves the returns to our unitholders on all future expansion projects.

Recent Developments

Marcellus Shale Processing Capacity Expansions

MarkWest Liberty Midstream & Resources, L.L.C ("MarkWest Liberty Midstream"), our joint venture with M&R MWE Liberty, LLC ("M&R"), an affiliate of The Energy & Minerals Group and its affiliated funds, operates in the natural gas midstream business in and around the Marcellus Shale in western Pennsylvania and northern West Virginia, which is an area characterized by the production of natural gas with a high NGL content referred to as rich gas. Equity interests in the entity were owned 60% by us and 40% by M&R until December 31, 2010. Effective January 1, 2011, we and M&R own equity interests of 51% and 49%, respectively. For further discussion, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 4 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

During 2010 we continued to expand the operations of MarkWest Liberty Midstream. In the third quarter of 2010, we commenced operations of a 135 MMcf/d cryogenic plant at our Majorsville site that is operating near capacity and completed an NGL pipeline that connects our Majorsville processing facility to our processing, fractionation and storage complex in Houston, Pennsylvania.

On January 4, 2011, MarkWest Liberty Midstream announced it will construct a 120 MMcf/d cryogenic gas processing facility and associated NGL pipeline located in Wetzel County, West Virginia by mid 2012 to process rich gas transported in EQT Energy, LLC's Equitrans gas pipeline, which recently announced a significant expansion to increase transmission capacity. EQT Energy, LLC has substantial rich-gas Marcellus acreage in northern West Virginia and has contracted with MarkWest Liberty Midstream for substantially all of the capacity of the Wetzel County plant. The NGLs recovered in Wetzel County will be transported via pipeline to MarkWest Liberty Midstream's Houston complex.

On January 19, 2011, MarkWest Liberty Midstream announced a long-term agreement with affiliates of Chesapeake Energy Corporation ("Chesapeake") to provide additional natural gas midstream services for Chesapeake's substantial rich-gas Marcellus acreage in northern West Virginia. MarkWest Liberty Midstream will provide the processing services at its Majorsville, West Virginia processing complex. The volumes processed under this agreement are expected to support substantially all of the capacity of a 135 MMcf/d cryogenic processing plant expected to be completed in the third quarter of 2011.

MarkWest Liberty Midstream is also developing commercial agreements to support a combined pipeline and marine project ("Mariner Project") to deliver purity ethane produced in the Marcellus Shale to Gulf Coast markets. The Mariner Project is a joint project with Sunoco Logistics and is anticipated to have initial capacity to transport up to 50,000 Bbl/d of ethane by 2013 and can be expanded to support additional Marcellus ethane production.

See *Our Operating Segments—Liberty Segment* below for additional discussion of MarkWest Liberty Midstream's operations and planned expansion.

Langley Acquisition

On January 3, 2011, our wholly-owned subsidiary MarkWest Energy Appalachia, L.L.C. ("MarkWest Appalachia") entered into a Purchase and Sale Agreement (the "Purchase and Sale Agreement") with EQT Gathering, LLC, a subsidiary of EQT Corporation (together with all of its affiliates, "EQT"). Pursuant to the Purchase and Sale Agreement, MarkWest Appalachia agreed to acquire from EQT certain gas processing facilities located near Langley and Maytown, Kentucky, consisting of a cryogenic natural gas processing plant with a capacity of approximately 100 MMcf/d and a refrigeration processing plant with a capacity of approximately 75 MMcf/d (together, the "Processing Facilities"), a partially constructed NGL pipeline (the "Ranger Pipeline") extending through parts of Kentucky and West Virginia, and certain other related assets, for a purchase price of approximately $230 million, subject to customary purchase price adjustments. We refer to this acquisition as the Langley Acquisition.

Upon closing of the Langley Acquisition on February 1, 2011, MarkWest Appalachia and EQT entered into a long-term agreement to process EQT's natural gas production in the region. In addition, MarkWest Appalachia is obligated to install an additional cryogenic natural gas processing plant with capacity of approximately 60 MMcf/d and to complete the construction of the Ranger Pipeline to connect the Processing Facilities to MarkWest Appalachia's existing NGL pipeline that transports NGLs to the Siloam NGL fractionation plant in South Shore, Kentucky.

Arapaho Processing Complex Expansion

On February 23, 2011, we announced the construction of a third plant at our Arapaho processing complex in Western Oklahoma to serve increasing volumes of rich natural gas production from Granite Wash producers, including Newfield Exploration and LINN Energy.

Since expanding our operations in late 2008 to serve producers in the Texas panhandle, our throughput volumes from the Granite Wash have increased to nearly 120 MMcf/d and are forecasted to continue increasing in 2011 and beyond. In addition, our producer customers are focusing their drilling plans on the rich zones in the Granite Wash, which has significantly increased the percentage of rich-gas volumes that we are gathering and processing. To support this growth, we will invest additional capital to expand our rich-gas gathering and compression facilities as well as our Arapaho processing complex. Upon completion of the facility expansions in the third quarter of 2011, the processing capacity at the Arapaho complex will increase by 60 MMcf/d to a total of 220 MMcf/d. The gathering and processing expansions are supported by long-term agreements with producer customers.

Amended and Restated Credit Agreement

In July 2010, we entered into an amended and restated credit agreement that provides for a revolving loan facility ("Credit Facility") of up to $705 million, with an uncommitted accordion feature of up to $195 million. For further discussion, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 17 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

Senior Notes Offerings and Tender Offers

In November 2010, we closed a public offering of $500 million aggregate principal amount of 6.75% senior notes due 2020 ("2020 Senior Notes"). We used the net proceeds of approximately $490.3 million to redeem all of our 6.875% senior notes due 2014 ("2014 Senior Notes"), to repay borrowings outstanding under the Credit Facility, and to provide working capital for general partnership purposes. For further discussion, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 17 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

On February 24, 2011, we closed a public offering of $300 million aggregate principal amount of 6.5% senior notes due 2021 ("2021 Senior Notes"). We received net proceeds of approximately $296 million after deducting the underwriting fees and other third-party expenses associated with the offering. We used the net proceeds to fund our concurrent repurchase of approximately $272.2 million in aggregate principal amount of our 8.5% senior notes due 2016 (the "2016 Senior Notes"), representing approximately 99% of the outstanding 2016 Senior Notes, pursuant to our tender offer for any and all of the outstanding 2016 Senior Notes. The tender offer for the 2016 Senior Notes will expire on March 9, 2011. Assuming no additional 2016 Senior Notes are tendered for repurchase prior to the expiration of the tender offer, we will record a pre-tax loss on redemption of debt of approximately $21 million in the first quarter of 2011, which will consist of approximately $1 million for the non-cash write off of the unamortized discount and deferred finance costs and approximately $20 million for the payment of the related tender premiums and third-party expenses.

On February 9, 2011, we commenced a tender offer for up to $125 million aggregate principal amount ("Tender Cap") of our outstanding 8.75% senior notes due 2018 (the "2018 Senior Notes"). On February 23, 2011, the Tender Cap was increased to $170 million and as of such date, holders of the 2018 Senior Notes had tendered approximately $165.5 million in aggregate principal amount of the outstanding 2018 Senior Notes for repurchase at various bid prices within the acceptable range of

$1,090.00 to $1,115.00 per $1,000 principal amount. The tender offer for the 2018 Senior Notes will expire on March 9, 2011. Assuming we complete the repurchase of the $165.5 million in aggregate principal amount of 2018 Senior Notes tendered for repurchase as of February 23, 2011 and no additional 2018 Senior Notes are tendered for repurchase prior to the expiration of the tender offer for the 2018 Senior Notes, we will record a pre-tax loss on redemption of debt of approximately $22 million in the first quarter of 2011, which will consist of approximately $3 million for the non-cash write off of the unamortized discount and deferred finance costs and approximately $19 million for the payment of the related tender premiums and third-party expenses.

Common Unit Offering

On January 14, 2011, we completed a public offering of approximately 3.45 million newly issued common units representing limited partner interests, which includes the full exercise of the underwriters' over-allotment option, at a price of $41.20 per common unit. Net proceeds of approximately $138 million were used to partially fund our ongoing capital expenditure program, including a portion of the costs associated with the Langley Acquisition.

Business Strategy

Our primary business strategy is to provide top-tier midstream services by developing and operating high-quality, strategically located assets in the rich-gas areas of the emerging resource plays in the United States. We plan to accomplish this through the following:

- *Developing long-term integrated relationships with our producer customers.* As a top-rated midstream service provider, we develop long-term, integrated relationships with key producer customers as evidenced by our relationships with the primary producers in the Woodford Shale, the Granite Wash, the Marcellus Shale and the Huron/Berea Shale. We will continue to develop relationships that are characterized by joint planning for the development of the emerging resource plays and our commitment to grow to meet the specific needs of our customers.

- *Expanding operations through organic growth projects.* By expanding our existing infrastructure and customer relationships, we intend to continue growing in our primary areas of operation to meet the anticipated demand for additional midstream services. During 2010, we spent approximately $458.7 million of total capital to develop midstream infrastructure in the Marcellus Shale through MarkWest Liberty Midstream and to expand several of our gathering and processing operations in our Southwest segment, including the Woodford gathering system in the Arkoma Basin, and the Stiles Ranch gathering system included in our western Oklahoma operations.

- *Expanding operations through strategic acquisitions.* We intend to continue pursuing strategic acquisitions of assets and businesses in our existing areas of operation that leverage our current asset base, personnel and customer relationships. We may also seek to acquire assets in certain regions outside of our current areas of operation. We believe that our capital structure, which no longer includes incentive distribution rights, positions us to compete more effectively for future transactions.

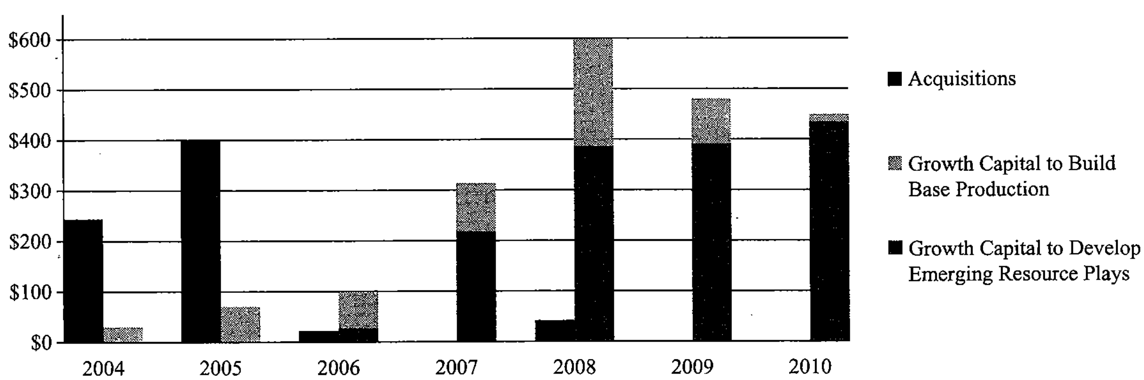
- *Maintaining our financial flexibility.* Our goal is to maintain a capital structure with approximately equal amounts of debt and equity on a long-term basis. During 2010 and the first quarter of 2011, we strategically accessed the debt and equity markets to fund our planned expansion projects and to effectively refinance a significant portion of our senior notes to realize lower interest rates and to extend the maturity dates. See Note 17 and Note 30 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion of the recent transactions related to our senior notes. We also entered into an amendment to our credit agreement to expand the borrowing capacity under our Credit Facility from $435.6 million to $705.0 million and to extend the term of our Credit Facility to July 2015.

As of December 31, 2010, we and our wholly-owned subsidiaries had approximately $63.9 million of cash and cash equivalents and approximately $677.6 million available for borrowing under our Credit Facility. We believe that our Credit Facility, our ability to issue additional partnership units and long-term debt, and our strong relationships with our existing joint venture partners will provide us with the financial flexibility to facilitate the execution of our business strategy.

- *Reducing the sensitivity of our cash flows to commodity price fluctuations.* We intend to continue to secure long-term, fee-based contracts in order to further reduce our exposure to short-term changes in commodity prices. We also engage in risk management activities in order to reduce the effect of commodity price volatility related to future sales of natural gas, NGLs and crude oil. We may utilize a combination of fixed-price forward contracts, fixed-for-floating price swaps, and options available in the over-the-counter market. We monitor these activities through enforcement of our commodity risk management policy. Please refer to Note 6 of the accompanying Notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion of our policy.
- *Increasing utilization of our facilities.* We seek to increase the utilization of our existing facilities by providing additional services to our existing customers, and by establishing relationships with new customers. We also continue to develop additional capacity at several of our facilities, which enables us to increase throughput with minimal incremental costs.

Execution of our business strategy has allowed us to grow substantially since our inception. The majority of our growth since 2007 has focused on the development of natural gas supplies in emerging resource plays. As a result we now have a strong presence in the Woodford Shale, Haynesville Shale, Granite Wash, Marcellus Shale and Huron/Berea Shale, five emerging resource plays that are expected to be a significant source of domestic natural gas production. The following table summarizes the magnitude of the growth projects and acquisitions, including equity investments (amounts in millions). The amounts include the portion of our growth projects funded by contributions from our joint venture partners.

Capital Investment



We believe that the following competitive strengths position us to continue to successfully execute our primary business strategy:

- *Leading position in the early development of the rich-gas area of the Marcellus Shale.* We are the largest processor of natural gas in the Marcellus Shale, with fully integrated processing, fractionation, storage and marketing operations that are critical to the rich-gas development in the northeast United States. Our operations are supported by strategic long-term agreements that include significant acreage dedications from key producers. Our gathering systems and processing plants in the Marcellus Shale are new and highly efficient and we continue to expand these facilities with a strong financial partner under the MarkWest Liberty Midstream joint venture arrangement.

- *Leading position in the Appalachian Basin.* We are the largest processor and fractionator of natural gas in Appalachia. We believe our significant presence and asset base provide us with a competitive advantage in capturing and contracting for new supplies of natural gas. Historically, the Appalachian Basin has been a large natural gas-producing region characterized by long-lived reserves with modest decline rates and natural gas with high NGL content. However, significant shale formations in the region such as the Huron/Berea Shale are now being developed. Our concentrated processing, fractionation and marketing infrastructure, land rights and storage assets in Appalachia should continue to provide us with a platform for additional cost-effective expansion opportunities as production from these shale formations continues to be developed.

- *Strategic and growing position with high-quality assets in the Southwest and the Gulf Coast.* Our acquisitions and internal growth projects have allowed us to establish and expand our presence in several long-lived natural gas supply basins in the Southwest, particularly in Texas and Oklahoma. In late 2006, we expanded this strategy through our agreement with Newfield Exploration Mid-Continent Inc. ("Newfield") by building the largest gathering system to date in the Woodford Shale play in Southeast Oklahoma. We have continued this strategy through the current development of our gathering system in the Granite Wash area under a similar arrangement with Newfield. All of our major acquisitions and growth projects in this region have been characterized by several common critical success factors that include:

  - an existing strong competitive position;
  - access to a significant reserve or customer base with a stable or growing production profile;
  - ample opportunities for long-term continued organic growth;
  - ready access to markets; and
  - close proximity to other acquisition or expansion opportunities.

  Specifically, our East Texas and Appleby gathering systems are located in the East Texas Basin, producing from or with direct access to the Cotton Valley, Pettit and Travis Peak reservoirs as well as the Haynesville and Bossier Shales. Our Foss Lake gathering system and the associated Arapaho gas processing plants are located in the Anadarko Basin in Oklahoma and are connected to the Granite Wash area in the Texas panhandle that is currently being developed as mentioned above. Additionally, as described above, our Woodford gathering system is located in the Woodford Shale reservoir. Our gathering systems are relatively new and provide producers with low-pressure and fuel-efficient service, a significant competitive advantage for us over many competing gathering systems in those areas.

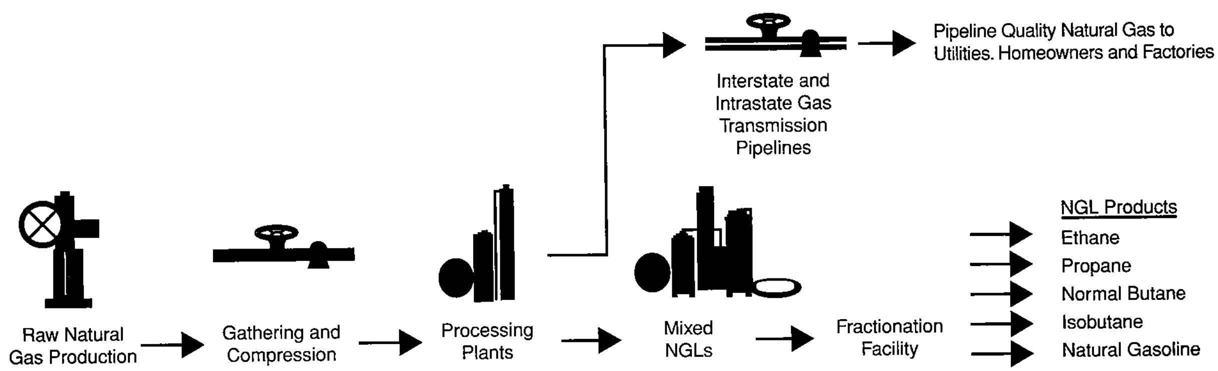
  Our Gulf Coast assets provide high quality service to six strategically located gulf coast refineries that we believe will continue to play a key role in supporting the long-term U.S. demand for refined petroleum products.

- *Long-term Contracts.* We believe our long-term contracts, which we define as contracts with remaining terms of four years or more, lend greater stability to our cash flow profile. In East Texas, approximately 65% of our current gathering volumes are under contract for longer than four years as of December 31, 2010. Approximately 59% of our current daily throughput in the Western Oklahoma gathering system and Arapaho processing plants are subject to contracts with remaining terms of more than seven years. Approximately 93% of our throughput in the Woodford gathering system is subject to contracts with remaining terms of more than six years. Also in the Southwest segment, two of our lateral pipelines operate under fixed-fee contracts for the transmission of natural gas that expire in approximately 18 and 10 years. In Appalachia, our natural gas processing and NGL fractionation contracts with remaining terms of more than five years account for approximately 86% of our volumes. In the Gulf Coast segment, approximately 30% of our volumes are under contract for more than four years. In the Liberty segment, all of our current gathering and processing agreements with significant dedicated acreage have remaining terms of at least ten years.

- *Experienced management with operational, technical and acquisition expertise.* Each member of our executive management team, whose interests are aligned with those of our common unitholders, has substantial experience in the energy industry. Our facility managers have extensive experience operating our facilities. Our operational and technical expertise has enabled us to upgrade our existing facilities, as well as to design and build new facilities. Since our initial public offering in May 2002, our management team has utilized a disciplined approach to analyze and evaluate numerous acquisition opportunities, and has completed eleven acquisitions as of December 31, 2010.

Industry Overview

We provide services in the midstream sector of the natural gas industry which includes natural gas gathering, transportation, processing and fractionation. The following diagram illustrates the typical natural gas gathering, natural gas processing and NGL fractionation processes:



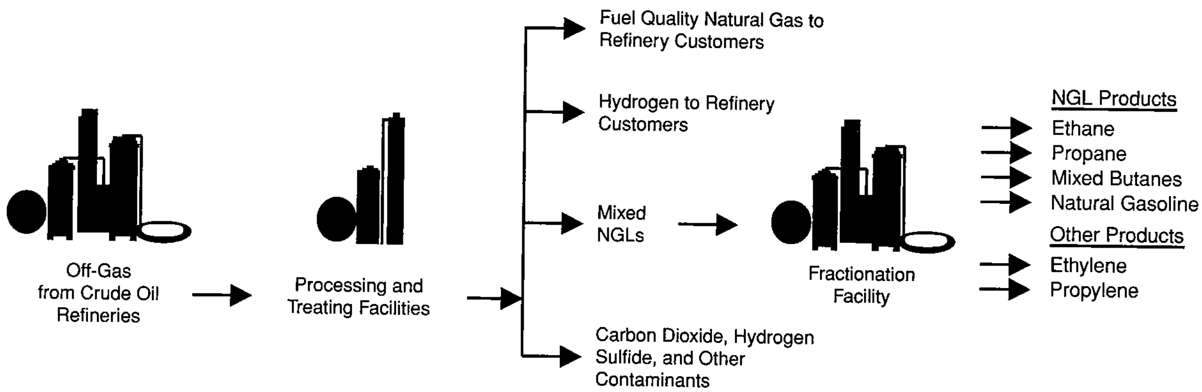
The natural gas production process begins with the drilling of wells into gas-bearing rock formations. The gathering process begins when a producing well is connected to a gathering system. Gathering systems typically consist of a network of small diameter pipelines and, if necessary, compression systems, that collect natural gas from points near producing wells, and transport it to larger pipelines for further transmission.

Historically, the majority of the domestic on-shore natural gas supply has been produced from conventional reservoirs that are characterized by large pockets of natural gas that are accessed successfully using vertical drilling techniques. In the past decade, the supply of natural gas production from the conventional sources has declined as these reservoirs are being depleted. Due to advances in well completion technology and horizontal drilling techniques, unconventional sources such as shale, tight sand and coal bed methane formations, have become the most significant source of current and expected future natural gas production. Due to the ability to economically produce natural gas from these emerging sources, current U.S. natural gas reserves are expected to provide at least 90 years of supply based on the U.S. Department of Energy's *Modern Shale Gas Development in the United States: A Primer* dated April 2009.

Natural gas has a widely varying composition, depending on the field, the formation reservoir or facility from which it is produced. The principal constituents of natural gas are methane and ethane. Most natural gas also contains varying amounts of heavier components, such as propane, butane, natural gasoline and inert substances that may be removed by any number of processing methods.

Most natural gas produced at the wellhead is not suitable for long-haul pipeline transportation or commercial use. It must be gathered, compressed and transported via pipeline to a central facility, and then processed and treated. Natural gas processing and treating involves the separation of raw natural gas into pipeline-quality natural gas, principally methane, and a mixed NGL stream, as well as the removal of contaminants that may interfere with pipeline transportation or the end-use of the gas. Our business includes providing these services either for a fee or a percentage of the NGLs removed or gas units processed. The industry as a whole is characterized by regional competition, based on the proximity of gathering systems and processing plants to producing natural gas wells, or to facilities that produce natural gas as a byproduct of refining crude oil. Due to the shift in the source of natural gas production, midstream providers with a significant presence in the emerging resource plays will likely have a competitive advantage.

We also provide processing and fractionation services to crude oil refineries in the Corpus Christi, Texas area through our Javelina gas processing and fractionation facility. While similar to the natural gas industry discussion above, the natural gas delivered to our Javelina processing plant is a product of the crude oil refining process. The following diagram illustrates the significant gas processing and fractionation processes at the Javelina facility:



The removal and separation of individual hydrocarbons and other constituents by processing is possible because of differences in physical properties. Each component has a distinctive weight, boiling point, vapor pressure and other physical characteristics. Natural gas may also be diluted or contaminated by water, sulfur compounds, carbon dioxide, nitrogen, helium or other components.

After being separated from natural gas at the processing plant, the mixed NGL stream is typically transported to a centralized facility for fractionation. Fractionation is the process by which NGLs are further separated into individual, more marketable components, primarily ethane, propane, normal butane, isobutane and natural gasoline. Fractionation systems typically exist either as an integral part of a gas processing plant or as a "central fractionator," often located many miles from the primary production and processing facility. A central fractionator may receive mixed streams of NGLs from many processing plants.

Basic NGL products and their typical uses are discussed below. The basic products are sold in all of our segments except as noted.

- *Ethane* is used primarily as feedstock in the production of ethylene, one of the basic building blocks for a wide range of plastics and other chemical products.

  Ethane is not recovered from the natural gas stream in our Northeast and Liberty segments as there is little petrochemical demand for ethane in the northeastern United States. However, ethane is produced and sold in our East Texas, Gulf Coast and Oklahoma operations.

- *Propane* is used for heating, engine and industrial fuels, agricultural burning and drying, and as a petrochemical feedstock for the production of ethylene and propylene. Propane is principally used as a fuel in our operating areas.
- *Normal butane* is mainly used for gasoline blending, as a fuel gas, either alone or in a mixture with propane, and as a feedstock for the manufacture of ethylene and butadiene, a key ingredient of synthetic rubber.
- *Isobutane* is primarily used by refiners to enhance the octane content of motor gasoline.
- *Natural gasoline* is principally used as a motor gasoline blend stock or petrochemical feedstock.

The other primary products produced and sold from our Javelina facility are discussed below.

- *Ethylene* is primarily used in the production of a wide range of plastics and other chemical products.
- *Propylene* is primarily used in manufacturing plastics, synthetic fibers and foams. It is also used in the manufacture of polypropylene, which has a variety of end uses including packaging film, carpet and upholstery fibers and plastic parts for appliances, automobiles, houseware and medical products.

Our Operating Segments

We conduct our operations in four geographic operating segments: Southwest, Northeast, Liberty and Gulf Coast. Our assets and operations in each of these segments are described below.

Southwest Segment

- *East Texas.* We own a system in East Texas that consists of natural gas gathering pipelines, centralized compressor stations, a natural gas processing facility and an NGL pipeline. The East Texas system is located in Panola, Harrison and Rusk Counties and services the Carthage Field. Producing formations in Panola County consist of the Cotton Valley, Pettit, Travis Peak and Haynesville formations. For natural gas that is processed in this area, we purchase the NGLs from the producers primarily under percent-of-proceeds arrangements, or we transport volumes for a fee.

  Approximately 81% of our natural gas volumes in the East Texas System result from contracts with six producers in 2010. We sell substantially all of the purchased and retained NGLs produced at our East Texas processing facility to Targa Resources Partners, L.P. ("Targa") under a long-term contract. Such sales represent approximately 16% of our consolidated revenue in 2010. For the year ended December 31, 2010, the contract contributed 6% to net operating margin (a non-GAAP measure, see *Our Contracts* below for discussion and reconciliation of net operating margin). The original term of the Targa agreement expires in December 2015.
- *Oklahoma.* We own a natural gas gathering system in the Woodford Shale play in the Arkoma Basin of southeast Oklahoma. Natural gas gathered in the Woodford system is processed by Centrahoma, our equity investment discussed in *Equity Investment in Unconsolidated Affiliate* below. In addition, we own the Foss Lake natural gas gathering system and the Arapaho I and II natural gas processing plants, all located in Roger Mills, Custer and Ellis Counties of western Oklahoma. The gathering portion consists of a pipeline system that is connected to natural gas wells and associated compression facilities. The majority of the gathered gas ultimately is compressed and delivered to the processing plants. We also own the Grimes gathering system that is located in Roger Mills and Beckham Counties in western Oklahoma and a gathering system in the Granite Wash formation in the Texas panhandle that is connected to our Arapaho processing plants. We plan to complete the recently-announced Arapaho III natural gas processing plant in the third quarter of 2011, which will increase our processing capacity at the Arapaho complex by 60 MMcf/d to a total of 220 MMcf/d. The gathering and processing expansions are supported by long-term agreements with producer customers.

Approximately 72% of our Oklahoma volumes result from contracts with three producers in 2010. The Oklahoma region has one customer to which we sell NGLs that accounts for a significant portion of the Southwest segment revenue, but sales to this customer do not account for a significant portion of our consolidated revenue in 2010.

Through our joint venture MarkWest Pioneer, we operate the Arkoma Connector Pipeline, a 50-mile FERC-regulated pipeline that interconnects with the Midcontinent Express Pipeline and Gulf Crossing Pipeline at Bennington, Oklahoma and is designed to provide approximately 638,000 Dth/d of Woodford Shale takeaway capacity. For a complete discussion of the formation of, and accounting treatment for, MarkWest Pioneer, see Note 4 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

- *Other Southwest.* We own a number of natural gas gathering systems located in Texas, Louisiana, Mississippi and New Mexico, including the Appleby gathering system in Nacogdoches County, Texas. We gather a significant portion of the gas produced from fields adjacent to our gathering systems, including from wells targeting the Haynesville Shale. In many areas we are the primary gatherer, and in some of the areas served by our smaller systems we are the sole gatherer. In addition, we own four lateral pipelines in Texas and New Mexico. Our Hobbs, New Mexico natural gas pipeline is subject to regulation by FERC.

  The Other Southwest area does not have any customers that we consider to be significant to the Southwest segment revenue or our consolidated revenue.

Northeast Segment

- *Appalachia.* We are the largest processor and fractionator of natural gas in the Appalachian Basin, with fully integrated processing, fractionation, storage and marketing operations. The Appalachian Basin is a large natural gas producing region characterized by long-lived reserves and modest decline rates. Our Appalachian assets include the Kenova, Boldman, Cobb, Kermit and recently acquired Langley natural gas processing plants, an NGL pipeline, and the Siloam NGL fractionation plant. We intend to construct additional processing plants as discussed above in *Recent Developments*. We also have two caverns for storing propane and additional propane storage capacity under a long-term firm-capacity agreement with a third party. The Appalachia operations include fractionation and marketing services provided on behalf of the Liberty segment.

  The Appalachia area has one customer that accounts for a significant portion of the Northeast segment revenue, but this customer does not account for a significant portion of our consolidated revenue.

- *Michigan.* We own and operate a FERC-regulated crude oil pipeline in Michigan ("Michigan Crude Pipeline") providing transportation service for three shippers.

Liberty Segment

- *Marcellus Shale.* We operate natural gas gathering and processing facilities located primarily in southwestern Pennsylvania and northern West Virginia through MarkWest Liberty Midstream. We are the largest processor of natural gas in the Marcellus Shale, with fully integrated processing, fractionation, storage and marketing operations that are critical to the rich-gas development in the northeast United States. We have 155 MMcf/d of cryogenic processing capacity at our Houston, Pennsylvania processing complex and we plan to complete the installation of a 200 MMcf/d cryogenic plant in the second quarter of 2011. We commenced operation of a 135 MMcf/d cryogenic plant at our Majorsville site in the third quarter of 2010 and we expect to increase the cryogenic processing capacity at our Majorsville site to approximately 270 MMcf/d by the third quarter of 2011. We will also construct a 120 MMcf/d cryogenic processing plant in Wetzel County, West Virginia and an NGL pipeline to connect the Wetzel County plant to our Majorsville processing complex. We expect the planned processing capacity discussed above to be supported by existing and new long-term agreements with our producer customers.

We also plan to complete a 60,000 Bbl/d fractionation facility at our Houston complex in 2011. Propane is recovered at our Houston processing complex. Further fractionation of the NGL stream produced at the Liberty processing plants will continue to be performed at the Siloam NGL fractionation plant in our Northeast segment until we have completed construction of our Houston fractionation facility. We also have an interconnect with a key interstate pipeline providing an additional market outlet for the propane produced from this region.

By mid 2012, MarkWest Liberty Midstream is expected to operate 745 MMcf/d of cryogenic processing capacity serving Marcellus rich-gas producers in southwestern Pennsylvania and northern West Virginia from its Houston, Majorsville, and recently announced Wetzel County processing complexes.

All of our volumes processed in the Liberty segment result from contracts with three producers. The resulting NGLs are sold to numerous customers in the northeast United States. There is one individual customer that we consider to be significant to the Liberty segment revenue but not to our consolidated revenue.

For a complete discussion of the formation of, and accounting treatment for, MarkWest Liberty Midstream, see Note 4 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

Gulf Coast Segment

- *Javelina.* We own and operate the Javelina processing facility, a natural gas processing facility in Corpus Christi, Texas that treats and processes off-gas from six local refineries operated by three different refinery customers. We have a product supply agreement creating a long-term contractual obligation for the payment of processing fees in exchange for all of the product processed by the steam methane reformer ("SMR") that is operated by a third party (see Note 5 of the accompanying Notes to Consolidated Financial Statements for further discussion of this agreement and the related SMR Transaction). The product received under this agreement will be sold to a refinery customer pursuant to a corresponding long-term agreement.

The following summarizes the percentage of our revenue and net operating margin (a non-GAAP financial measure, see *Our Contracts* discussion below) generated by our assets, by segment, for the year ended December 31, 2010:

	Southwest	Northeast	Liberty	Gulf Coast	Total
Revenue	54%	31%	8%	7%	100%
Net operating margin	54%	20%	13%	13%	100%

For further financial information regarding our segments, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data included in this Form 10-K.

Equity Investment in Unconsolidated Affiliate

We own a 40% non-operating membership interest in Centrahoma Processing LLC ("Centrahoma"), a joint venture with Cardinal Midstream, LLC that is accounted for using the equity method. Centrahoma owns certain processing plants in the Arkoma Basin. We have signed long-term agreements to dedicate the processing rights for our natural gas gathering system in the Woodford Shale to Centrahoma. The financial results for Centrahoma are included in *Earnings from unconsolidated affiliates* and are not included in our segment results.

Our Contracts

We generate the majority of our revenues and net operating margin (a non-GAAP financial measure, see *Net Operating Margin* below for discussion and reconciliation of net operating margin) from natural gas gathering, transportation and processing; NGL transportation, fractionation, marketing and storage; and crude oil gathering and transportation. We enter into a variety of contract types. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described below. We provide services under the following types of arrangements:

- *Fee-based arrangements:* Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, processing and transportation of natural gas; transportation, fractionation and storage of NGLs; and gathering and transportation of crude oil. The revenue we earn from these arrangements is generally directly related to the volume of natural gas, NGLs or crude oil that flows through our systems and facilities and is not directly dependent on commodity prices. If a sustained decline in commodity prices were to result in a decline in volumes, however, our revenues from these arrangements would be reduced. In certain cases, our arrangements provide for minimum annual payments, fixed demand charges, or fixed returns on gathering system expenditures.

- *Percent-of-proceeds arrangements:* Under percent-of-proceeds arrangements, we gather and process natural gas on behalf of producers, sell the resulting residue gas, condensate and NGLs at market prices and remit to producers an agreed-upon percentage of the proceeds. In other cases, instead of remitting cash payments to the producer, we deliver an agreed-upon percentage of the residue gas and NGLs to the producer and sell the volumes we keep to third parties at market prices. The percentage of volumes that we retain can be either fixed or variable. Generally, under these types of arrangements our revenues and gross margins increase as natural gas, condensate and NGL prices increase, and our revenues and net operating margins decrease as natural gas, condensate and NGL prices decrease.

- *Percent-of-index arrangements:* Under percent-of-index arrangements, we purchase natural gas at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount or (3) a percentage discount to a specified index price less an additional fixed amount. We then gather and deliver the natural gas to pipelines where we resell the natural gas at the index price, or at a different percentage discount to the index price. With respect to (1) and (3) above, the net operating margins we realize under the arrangements decrease in periods of low natural gas prices because these net operating margins are based on a percentage of the index price. Conversely, our net operating margins increase during periods of high natural gas prices.

- *Keep-whole arrangements:* Under keep-whole arrangements, we gather natural gas for the producer, process the natural gas, and sell the resulting condensate and NGLs to third parties at market prices. Because the extraction of NGLs from the natural gas during processing reduces the Btu content of the natural gas, we must either purchase natural gas at market prices for return to producers or make cash payment to the producers equal to the energy content of this natural gas. Certain keep-whole arrangements also have provisions that require us to share a percentage of the keep-whole profits with the producers based on the oil to gas ratio or the relative price of NGLs to natural gas. Accordingly, under these arrangements our revenues and net operating margins increase as the price of condensate and NGLs increases relative to the price of natural gas, and decrease as the price of natural gas increases relative to the price of condensate and NGLs.

- *Settlement margin:* Typically, we are allowed to retain a fixed percentage of the volume gathered to cover the compression fuel charges and deemed-line losses. To the extent that we operate our gathering systems more or less efficiently than specified per contract allowance, we will retain the benefit or loss for our own account.

The terms of our contracts vary based on gas quality conditions, the competitive environment when the contracts are signed and customer requirements. Our contract mix and, accordingly, our exposure to natural gas and NGL prices, may change as a result of changes in producer preferences, our expansion in regions where some types of contracts are more common and other market factors, including current market and financial conditions which have increased the risk of volatility in oil, natural gas and NGL prices. Any change in mix will influence our long-term financial results.

Net Operating Margin

Management evaluates contract performance on the basis of net operating margin (a non-GAAP financial measure), which is defined as revenue, excluding any derivative gain (loss), less purchased product costs, excluding any derivative gain (loss). These charges have been excluded for the purpose of enhancing the understanding by both management and investors of the underlying baseline operating performance of our contractual arrangements, which management uses to evaluate our financial performance for purposes of planning and forecasting. Net operating margin does not have any standardized definition and therefore is unlikely to be comparable to similar measures presented by other reporting companies. Net operating margin results should not be evaluated in isolation of, or as a substitute for, our financial results prepared in accordance with GAAP. Our use of net operating margin and the underlying methodology in excluding certain charges is not necessarily an indication of the results of operations expected in the future, or that we will not, in fact, incur such charges in future periods.

The following is a reconciliation to income from operations, the most comparable GAAP financial measure of this non-GAAP financial measure (in thousands):

	Year ended December 31,		
	2010	2009	2008
Revenue	$1,241,563	$858,635	$1,060,662
Purchased product costs	578,627	408,826	615,902
Net operating margin	662,936	449,809	444,760
Facility expenses	151,449	126,977	103,682
Derivative loss (gain)	80,350	188,862	(254,813)
Selling, general and administrative expenses	75,258	63,728	68,975
Depreciation	123,198	95,537	67,480
Amortization of intangible assets	40,833	40,831	38,483
Loss on disposal of property, plant and equipment	3,149	1,677	178
Accretion of asset retirement obligations	237	198	129
Impairment of goodwill and long-lived assets	—	5,855	36,351
Income (loss) from operations	$ 188,462	$(73,856)	$ 384,295

The following table does not give effect to our active commodity risk management program. For further discussion of how we have reduced the downside volatility to the portion of our net operating margin that is not fee-based, see Note 6 of the accompanying Notes to the Consolidated Financial

Statements included in Item 8 of this Form 10-K. For the year ended December 31, 2010, we calculated the following approximate percentages of our revenue and net operating margin from the following types of contracts:

	Fee-Based	Percent-of-Proceeds(1)	Percent-of-Index(2)	Keep-Whole(3)	Total
Revenue	21%	40%	3%	36%	100%
Net operating margin(4)	38%	32%	0%	30%	100%

(1) Includes condensate sales and other types of arrangements tied to NGL prices.

(2) Includes arrangements tied to natural gas prices.

(3) Includes condensate sales and other types of arrangements tied to both NGL and natural gas prices.

(4) We manage our business by taking into account the partial offset of short natural gas positions by long positions primarily in our Southwest segment. The calculated percentages for the net operating margin for percent-of-proceeds, percent-of-index and keep-whole contracts reflect the partial offset of our natural gas positions.

Competition

In each of our operating segments, we face competition for natural gas and crude oil transportation and in obtaining natural gas supplies for our processing and related services; in obtaining unprocessed NGLs for fractionation; and in marketing our products and services. Competition for natural gas supplies is based primarily on the location of gas-gathering facilities and gas-processing plants, operating efficiency and reliability, and the ability to obtain a satisfactory price for products recovered. Competitive factors affecting our fractionation services include availability of capacity, proximity to supply and industry marketing centers, and cost efficiency and reliability of service. Competition for customers is based primarily on price, delivery capabilities, flexibility and maintenance of high-quality customer relationships.

Our competitors include:

- other large natural gas gatherers that gather, process and market natural gas and NGLs;
- major integrated oil companies;
- medium and large sized independent exploration and production companies;
- major interstate and intrastate pipelines; and
- a large number of smaller gas gatherers of varying financial resources and experience.

Many of our competitors operate as master limited partnerships and enjoy a cost of capital comparable to and, in some cases, lower than ours. Other competitors, such as major oil and gas and pipeline companies, have capital resources and control supplies of natural gas substantially greater than ours. Smaller local distributors may enjoy a marketing advantage in their immediate service areas.

We believe that our customer focus in all segments, demonstrated by our ability to offer an integrated package of services and our flexibility in considering various types of contractual arrangements, allows us to compete more effectively. Additionally, we have critical connections to the key market outlets for NGLs and natural gas in each of our segments. In the Southwest segment our major gathering systems are relatively new and provide producers with low-pressure and fuel-efficient service, which differentiates us from many competing gathering systems in those areas. In the Northeast segment, our operational experience of more than 20 years and our existing presence in the Appalachian Basin provide a significant competitive advantage. In the Liberty segment, our early entrance in the Marcellus Shale through our strategic gathering and processing agreements with key producers enhances our competitive position to participate in the further development of the Marcellus Shale. In our Gulf Coast segment, the strategic location of our assets and the long-term nature of our contracts provide a significant competitive advantage.

Seasonality

Our business is affected by seasonal fluctuations in commodity prices. Sales volumes also are affected by various other factors such as fluctuating and seasonal demands for products, changes in transportation and travel patterns and variations in weather patterns from year to year. Our Northeast segment is particularly impacted by seasonality. In our Northeast segment operations, we store a portion of the propane that is produced in the summer to be sold in the winter months. As a result of our seasonality, we generally expect the sales volumes in our Northeast segment to be higher in the first quarter and fourth quarter. These seasonal factors also impact our Liberty segment; however, the expected growth and expansion in our Liberty segment in 2011 will offset this seasonality impact.

Regulatory Matters

Our operations are subject to extensive regulations. The failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on our operations increases our cost of doing business and, consequently, affects our profitability. However, we do not believe that we are affected in a significantly different manner by these laws and regulations than are our competitors. Due to the myriad of complex federal, state, provincial and local regulations that may affect us, directly or indirectly, reliance on the following discussion of certain laws and regulations should not be considered an exhaustive review of all regulatory considerations affecting our operations.

FERC-Regulated Gas Pipelines. Our natural gas pipeline operations are subject to federal, state and local regulatory authorities. Specifically, our Hobbs, New Mexico natural gas pipeline and our Arkoma Connector natural gas pipeline in Oklahoma are subject to regulation by FERC. Federal regulation extends to such matters as:

- rate structures;
- return on equity;
- recovery of costs;
- the services that our regulated assets are permitted to perform;
- the acquisition, construction and disposition of assets; and
- to an extent, the level of competition in that regulated industry.

Under the Natural Gas Act ("NGA"), FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Its authority to regulate those services includes the rates charged for the services, terms and conditions of service, certification and construction of new facilities, the extension or abandonment of services and facilities, the maintenance of accounts and records, the acquisition and disposition of facilities, the initiation and discontinuation of services, and various other matters. Natural gas companies may not charge rates that have been determined not to be just and reasonable by FERC. In addition, FERC prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service. The rates and terms and conditions for our service will be found in FERC-approved tariffs. Pursuant to FERC's jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. We cannot assure you that FERC will continue to pursue its approach of procompetitive policies as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity, and transportation facilities. Any successful complaint or protest against our rates, or loss of market-based rate authority by FERC could have an adverse impact on our revenues associated with providing interstate gas transportation services.

Energy Policy Act of 2005. On August 8, 2005, President Bush signed into law the Domenici-Barton Energy Policy Act of 2005 ("2005 EPAct"). Under the 2005 EPAct, FERC may impose civil penalties of up to $1,000,000 per day for each current violation of the NGA or the Natural Gas Policy Act of 1978. The 2005 EPAct also amends the NGA to add an anti-market manipulation provision, which makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by FERC. FERC issued Order No. 670 to implement the anti-market manipulation provision of 2005 EPAct. This order makes it unlawful for gas pipelines and storage companies that provide interstate services to: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's enforcement authority. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot assure you that present policies pursued by FERC and Congress will continue.

Standards of Conduct. On October 16, 2008, FERC issued a Final Rule ("Order 717") revising the FERC Standards of Conduct for natural gas and electric transmission providers by eliminating its earlier concept of Energy Affiliates and corporate separation in favor of an employee functional approach. A transmission provider is prohibited from disclosing to a marketing function employee non-public information about the transmission system or a transmission customer. Order 717 also retains the long-standing no-conduit rule, which prohibits a transmission function provider from disclosing non-public information to marketing function employees by using a third party conduit. Additionally, Order 717 requires that a transmission provider provide annual training on the Standards of Conduct to all transmission function employees, marketing function employees, officers, directors, supervisory employees, and any other employees likely to become privy to transmission function information. This rule became effective November 26, 2008.

FERC issued Order 717-A, an order on rehearing and clarification of Order 717, on October 15, 2009. FERC further clarified Order 717-A in Order 717-B, which was issued on November 16, 2009, and in Order 717-C, which was issued on April 16, 2010. However, Orders 717-B and 717-C did not substantively alter the rules promulgated under Orders 717 and 717-A. Requests for rehearing of Order 717-C have been filed and are currently pending before FERC.

Market Transparency Rulemakings. In 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order 704"). The order became effective February 4, 2008. Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors and natural gas marketers, are now required to report, on May 1 of each year, beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which transactions should be reported based on the guidance of Order 704. Order 704 will require most, if not all of our natural gas pipelines to report annual volumes of relevant transactions to FERC.

On November 20, 2008, FERC issued a final rule on daily scheduled flows and capacity posting requirements ("Order 720"). Under Order 720, certain non-interstate pipelines delivering, on an annual basis, more than an average of 50 million MMBtu of gas over the previous three (3) calendar years, are required to post daily certain information regarding the pipeline's capacity and scheduled flows for each receipt and delivery point that has a design capacity equal to or greater than 15,000 MMBtu per day and interstate pipelines are required to post information regarding the provision of no-notice service. FERC has since issued two orders clarifying Order 720, including Order 720-A on January 21, 2010 and Order 720-B on July 21, 2010. A petition for review of Orders 720 and 720-A has been filed and is currently pending before the Court of Appeals for the Fifth Circuit. We have no way to predict with certainty whether and to what extent Orders 720 and 720-A may be modified as a result of the petition for review.

Regulation of Natural Gas Gathering Pipelines and Intrastate Pipelines. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC. We own a number of facilities, including a pipeline that connects the Stiles Ranch gathering assets to our Arapaho processing plants, that we believe meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. We cannot provide assurance, however, that FERC will not at some point assert that transportation on these facilities is within its jurisdiction, or that such an assertion would not adversely affect our results of operations. In such a case, we would be required to file a tariff with FERC and provide a cost justification for the transportation charge.

In the states in which we operate, regulation of gathering facilities and intrastate pipeline facilities generally includes various safety, environmental and, in some circumstances, open access, nondiscriminatory take requirement and complaint-based rate regulation. For example, some of our natural gas gathering facilities are subject to state ratable take and common purchaser statutes and regulations. Ratable take statutes and regulations generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes and regulations generally require gatherers to purchase gas without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. Although state regulation is typically less onerous than at FERC, these statutes and regulations have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that FERC has taken a less stringent approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

NGL Pipelines. Our Appalachian pipeline carries NGLs across state lines, and we are in the process of constructing additional NGL pipelines in Kentucky and West Virginia that will carry NGLs across state lines. We neither operate our Appalachian pipeline as a common carrier, nor hold it out for service to the public, and we do not intend to do either of the foregoing with respect to the NGL pipelines that are under construction. We own all NGLs shipped on the existing NGL pipeline and expect to own all NGLs shipped on the two pipelines still under construction. There are no third-party shippers on the existing Appalachian pipeline and we believe the likelihood of third-party shippers seeking to use the two NGL pipelines under construction is remote. Accordingly, we believe these facilities should not be subject to regulation by FERC or these pipelines would qualify for a waiver from FERC's applicable regulatory requirements. However, we cannot provide assurance that FERC will not at some point, either at the request of other entities or on its own initiative, assert that some or all of such transportation is within its jurisdiction, or that such an assertion would not adversely affect our results of operations. In the event FERC were to successfully assert jurisdiction, and not otherwise grant waiver of any applicable regulatory requirements, we would be required to file a tariff with FERC, provide a cost justification for the transportation charge and provide service to all potential shippers without undue discrimination.

Propane Regulation. National Fire Protection Association Pamphlets No. 54 and No. 58, which establish rules and procedures governing the safe handling of propane, or comparable regulations, have been adopted as the industry standard in all of the states in which we operate. In some states these laws are administered by state agencies, and in others they are administered on a municipal level. With respect to the transportation of propane by truck, we are subject to regulations promulgated under the Federal Motor Carrier Safety Act. These regulations cover the transportation of hazardous materials and are administered by the DOT. We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We maintain various permits that are necessary to operate our facilities, some of which may be material to our propane operations. We believe that the procedures currently in effect at all of our facilities for the handling, storage and distribution of propane are consistent with industry standards and are in compliance in all material respects with applicable laws and regulations.

Crude Common Carrier Pipeline Operations. Our Michigan Crude Pipeline is a crude oil pipeline that is a common carrier and subject to regulation by FERC under the October 1, 1977 version of the Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992 ("EPAct 1992"). The ICA and its implementing regulations give FERC authority to regulate the rates charged for service on the interstate common carrier liquids pipelines and generally require the rates and practices of interstate liquids pipelines to be just and reasonable and nondiscriminatory. The ICA also requires these pipelines to keep tariffs on file with FERC that set forth the rates the pipeline charges for providing transportation services and the rules and regulations governing these services. EPAct 1992 and its implementing regulations allow interstate common carrier oil pipelines to annually index their rates up to a prescribed ceiling level. FERC retains cost-of-service ratemaking, market-based rates and settlement rates as alternatives to the indexing approach.

On February 24, 2009, we filed to increase our rates on the Michigan Crude Pipeline, effective April 1, 2009, to incorporate index increases that were not fully taken over the prior three years because of a previously effective settlement that had since expired. FERC rejected the filing and denied a request for rehearing. We filed an appeal of FERC's decision at the Court of Appeals for the District of Columbia Circuit. The Court held an oral argument on our appeal on January 18, 2011, but, to date, the Court has not issued an order on this matter.

On July 30, 2010, we made a cost-of-service filing at FERC to increase our rates for transportation on the Michigan Crude Pipeline. Several parties protested this filing and on August 31, 2010, FERC accepted the filing, effective September 1, 2010, subject to refund. FERC also established a hearing to investigate the issues raised by the protestors, but ordered the hearing to be held in abeyance pending the result of settlement discussions between the parties. Those settlement discussions are still continuing before a FERC Settlement Judge.

Environmental Matters

General.

Our processing and fractionation plants, pipelines, and associated facilities are subject to multiple obligations and potential liabilities under a variety of stringent and comprehensive federal, state and local laws and regulations governing discharges of materials into the environment or otherwise relating to environmental protection. Such laws and regulations affect many aspects of our present and future operations, such as requiring the acquisition of permits or other approvals to conduct regulated activities that may impose burdensome conditions or potentially cause delays, restricting the manner in which we handle or dispose of our wastes, limiting or prohibiting activities in sensitive areas such as wetlands, ecologically-sensitive areas, or areas inhabited by endangered species, requiring us to incur capital costs to construct, maintain and upgrade equipment and facilities, restricting the locations in which we may construct our compressor stations and other facilities or requiring the relocation of existing stations and facilities, and requiring remedial actions to mitigate pollution caused by our operations or attributable to former operations. Failure to comply with these stringent and comprehensive requirements may expose us to the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining or limiting some or all of our operations.

We believe that our operations and facilities are in substantial compliance with applicable environmental laws and regulations, and that the cost of continued compliance with such laws and regulations will not have a material adverse effect on our results of operations or financial condition. We cannot ensure, however, that existing environmental laws and regulations will not be reinterpreted or revised or that new laws and regulations will not be adopted or become applicable to us. The clear trend in environmental law is to place more restrictions and limitations on activities that may be perceived to affect the environment. Thus there can be no assurance as to the amount or timing of future expenditures for compliance with environmental laws and regulations or remediation pursuant to such requirements, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional environmental requirements that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial condition, results of operations and cash flow. We may not be able to recover some or any of these costs from insurance.

Hazardous Substance and Waste.

To a large extent, the environmental laws and regulations affecting our operations relate to the release of hazardous substances or solid wastes into soils, groundwater, and surface water, and include measures to control pollution of the environment. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act, as amended, or CERCLA, also known as the "Superfund" law, and comparable state laws, impose liability without regard to fault or the legality of the original conduct, on certain classes of persons. These persons include current and prior owners or operators of a site where a release occurred and companies that transported or disposed or arranged for the off-site treatment or disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to strict and, under certain circumstances, joint and several liability for the costs of removing or remediating hazardous substances that have been released into the environment, for restoration costs and damages to natural resources, and for the costs of certain health studies. Additionally, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. While we generate materials in the course of our operations that are defined as hazardous substances under CERCLA or similar state statutes, we do not believe that we have any current material liability for cleanup costs under such laws, or for third party claims or personal injury or property damage. We also may incur liability under the Resource Conservation and

Recovery Act, as amended, or RCRA, and comparable state statutes, which impose requirements relating to the handling and disposal of hazardous wastes and nonhazardous solid wastes. We are not currently required to comply with a substantial portion of the RCRA requirements because our operations generate minimal quantities of hazardous wastes. However, it is possible that some wastes generated by us that are currently classified as nonhazardous may in the future be designated as hazardous wastes, resulting in the wastes being subject to more rigorous and costly transportation, treatment and/or disposal requirements.

We currently own or lease, and have in the past owned or leased, properties that have been used over the years for natural gas gathering, processing and transportation, for NGL fractionation, or for the storage, gathering and transportation of crude oil. Although solid waste disposal practices within the NGL industry and other oil and natural gas related industries have improved over the years, a possibility exists that petroleum hydrocarbons and other solid wastes or hazardous wastes may have been disposed of on or under various properties owned or leased by us during the operating history of those facilities. In addition, a number of these properties may have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons or other wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA, and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination or to perform remedial operations to prevent future contamination. We do not believe that there presently exists significant surface and subsurface contamination of our properties by petroleum hydrocarbons or other solid wastes for which we are currently responsible.

Ongoing Remediation and Indemnification from a Third Party.

The previous or current third-party owner or operator of our Cobb, Boldman, Kenova, Kermit and Majorsville facilities has been, or is currently involved in, investigatory or remedial activities with respect to the real property underlying these facilities. These investigatory and remedial obligations arise out of a September 1994 "Administrative Order by Consent for Removal Actions" with EPA Regions II, III, IV, and V; and with respect to the Boldman facility, an "Agreed Order" entered into by the previous or current third-party owner/operator with the Kentucky Natural Resources and Environmental Protection Cabinet in October 1994. The previous owner/operator has accepted sole liability and responsibility for, and indemnifies us against, any environmental liabilities associated with the EPA Administrative Order, the Kentucky Agreed Order or any other environmental condition related to the real property prior to the effective dates of our lease or purchase of the real property. In addition, the previous owner/operator has agreed to perform all the required response actions at its expense in a manner that minimizes interference with our use of the properties. We understand that to date, all actions required under these agreements have been or are being performed and, accordingly, we do not believe that the remediation obligation of these properties will have a material adverse impact on our financial condition or results of operations.

Water.

The Federal Water Pollution Control Act of 1972, as amended, also known as the "Clean Water Act," and analogous state laws impose restrictions and controls on the discharge of pollutants into federal and state waters. Such discharges are prohibited, except in accord with the terms of a permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a hydrocarbon tank spill, rupture or leak. Any unpermitted release of pollutants, including oil, natural gas liquids or condensates, could result in penalties, as well as significant remedial obligations. In addition, the Clean Water Act and analogous state law may also require individual permits or coverage under general permits for discharges of stormwater from certain types of facilities, but these requirements are subject to several exemptions specifically related to oil and gas operations and facilities. We conduct regular review of the applicable laws and regulations, and maintain discussions with the various federal, state and local agencies with regard to the application of those laws and regulations to our facilities, including the permitting process and categories of applicable permits for stormwater or other discharges, stream crossings and wetland disturbances that may be required for the construction or operation of certain of our facilities in the state. We believe that we are in substantial compliance with the Clean Water Act and analogous state laws.

Activities of natural gas exploration and production operators with whom we have a business relationship may include the performance of hydraulic fracturing to enhance the production of natural gas from formations with low permeability, such as shales. Due to concerns raised concerning potential impacts of hydraulic fracturing on groundwater quality, the EPA has commenced a study on the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012, and a committee of the U.S. House of Representatives is conducting an investigation of hydraulic fracturing practices. In addition, legislation was proposed in the recently completed session of Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process, and such legislation could be introduced in the current session of Congress. Moreover, legislative and regulatory efforts in some states have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing. Such efforts could have an adverse effect on natural gas production activities in shale formations, including the Marcellus Shale, which in turn could have an adverse effect on the gathering, transportation, processing and/or fractionation services that we render for our exploration and production customers.

Air and Greenhouse Gases.

The Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources in the U.S., including processing plants and compressor stations, and also impose various monitoring and reporting requirements. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements, utilize specific equipment or technologies to control emissions, or may be subject to reinterpretation and require the co-location of our facilities for permitting purposes. Amendments, expansions or re-interpretations of the Clean Air Act or comparable state laws may cause us to incur capital expenditures for installation of air pollution control equipment and to encounter construction delays while applying for and receiving new or amended permits. We have been in discussions with various state agencies in the areas we operate with respect to their guidance, policies, rules and regulations regarding the permitting process, source determination, categories of applicable permits and control technology that may be required for the construction or operation of certain of our facilities. We believe that our operations are in substantial compliance with applicable air permitting and control technology requirements.

As a consequence to an EPA administrative conclusion that emissions of carbon dioxide, methane, and other greenhouse gases, or GHGs, into the ambient air causes or contributes to air pollution which may reasonably be anticipated to endanger public health and welfare, EPA, has adopted regulations that require a reduction in emissions of GHGs from motor vehicles and also may trigger construction and operating permit review for GHG emissions from certain stationary sources. The EPA has published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs, pursuant to which these permitting programs have been "tailored" to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. On October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including natural gas liquids fractionators, beginning in 2011 for emissions occurring in 2010. Moreover, on November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule to include onshore and offshore oil and natural gas production and onshore oil and natural gas processing, transmission, storage, and distribution activities, which may include certain of our operations, beginning in 2012 for emissions occurring in 2011. As a result of these requirements—all of which are currently subject to judicial review in the Court of Appeals for the District of Columbia—we may be required to incur certain capital expenditures for air pollution control equipment in connection with maintaining or obtaining preconstruction and operating permits, and we may encounter construction delays in connection with the applying for and receiving required permits.

In addition, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we process or fractionate. It is not possible at this time to predict the full or final scope of legislation or new regulations that may be adopted to address greenhouse gas emissions or the impact of such legislation or regulations on our business. However, any such new federal, regional, or state restrictions on emissions of carbon dioxide or other greenhouse gases that may be imposed in areas in which we conduct business could have an adverse affect on our cost of doing business and on the demand for the natural gas and crude oil we gather as well as the natural gas and natural gas liquids we process, which in turn could adversely affect our cash available for distribution to our unitholders.

Anti-Terrorism Measures.

Our operations and the operations of the natural gas and oil industry in general may be subject to laws and regulations regarding the security of industrial facilities, including natural gas and oil facilities. The Department of Homeland Security Appropriations Act of 2007 required the Department of Homeland Security ("DHS") to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present "high levels of security risk." The DHS issued an interim final rule, known as the Chemical Facility Anti-Terrorism Standards interim rule, in April 2007 regarding risk-based performance standards to be attained pursuant to the act and on November 20, 2007 further issued an Appendix A to the interim rule that established the chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. Covered facilities that are determined by DHS to pose a high level of security risk are required to prepare and submit Security Vulnerability Assessments and Site Security Plans as well as comply with other regulatory requirements, including those regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information. In January 2008, we prepared and submitted to the DHS initial screening surveys for facilities operated by us that possess regulated chemicals of interest in excess of the Appendix A threshold levels. During 2008, the DHS requested that we perform a Security Vulnerability Assessment for our Javelina plant. The DHS did not require us to perform any assessments with respect to our other facilities. We completed the assessment for our Javelina plant and submitted the assessment to the DHS for review in December 2008. We are also required to develop a written security plan for our Javelina plant and train our employees accordingly. In March 2010, we received a response from the DHS approving our Security

Vulnerability Assessment and requesting that we develop and submit a Site Security Plan for the Javelina plant. We submitted the Site Security Plan to the DHS for review in June 2010. While we do not currently anticipate incurring significant costs in connection with complying with these requirements, we have not yet received a response from the DHS regarding our Site Security Plan. It is possible that additional requirements could be imposed by the DHS in connection with this program, and complying with such requirements could result in additional costs that may be substantial.

Pipeline Safety Regulations

Our pipelines are subject to regulation by the U.S. Department of Transportation ("DOT") under the Natural Gas Pipeline Safety Act of 1986, as amended ("NGPSA"), with respect to natural gas, and the Hazardous Pipeline Safety Act of 1979, as amended ("HLPSA"), with respect to crude oil, NGLs and condensates. The NGPSA and HLPSA govern the design, installation, testing, construction, operation, replacement and management of natural gas, oil and NGL pipeline facilities. The NGPSA and HLPSA require any entity that owns or operates pipeline facilities to comply with the regulations implemented under these acts, permit access to and allow copying of records, and to make certain reports and provide information as required by the Secretary of Transportation. We believe that our pipeline operations are in substantial compliance with applicable existing NGPSA and HLPSA requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, future compliance with the NGPSA and HLPSA could result in increased costs.

Our pipelines are also subject to regulation by the DOT under the Pipeline Safety Improvement Act of 2002, which was amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. The DOT, through the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), has established a series of rules under 49 C.F.R. Part 192 that require pipeline operators to develop and implement integrity management programs for gas transmission pipelines that, in the event of a failure, could affect high consequence areas. "High consequence areas" are currently defined to include high population areas, areas unusually sensitive to environmental damage and commercially navigable waterways. Similar rules are also in place under 49 C.F.R. Part 195 for operators of hazardous liquid pipelines including lines transporting NGLs and condensates. The DOT also adopted rules in June 2008 pursuant to authorization granted by the Pipeline Inspections, Protection, Enforcement, and Safety Act of 2006 that amends the pipeline safety regulations to extend regulatory coverage to certain rural onshore hazardous liquid gathering lines and low stress pipelines located in specified "unusually sensitive areas," including non-populated areas requiring extra protection because of the presence of sole source drinking water resources, endangered species or other ecological sources. While we believe that our pipeline operations are in substantial compliance with applicable requirements, due to the possibility of new or amended laws and regulations, or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with the requirements will not have a material adverse effect on our results of operations or financial position.

Employee Safety

The workplaces associated with the processing and storage facilities and the pipelines we operate are also subject to oversight pursuant to the federal Occupational Safety and Health Act, as amended, ("OSHA"), as well as comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard-communication standard requires that we maintain information about hazardous materials used or produced in operations, and that this information be provided to employees, state and local government authorities, and citizens. We believe that we have conducted our operations in substantial compliance with OSHA requirements, including general industry standards, record-keeping requirements and monitoring of occupational exposure to regulated substances.

In general, we expect industry and regulatory safety standards to become stricter over time, resulting in increased compliance expenditures. While these expenditures cannot be accurately estimated at this time, we do not expect such expenditures will have a material adverse effect on our results of operations.

Employees

Through our subsidiary MarkWest Hydrocarbon, we employ approximately 590 individuals to operate our facilities and provide general and administrative services. We have no employees represented by unions.

Available Information

Our principal executive office is located at 1515 Arapahoe Street, Tower 1, Suite 1600, Denver, Colorado 80202-2137. Our telephone number is 303-925-9200. Our common units trade on the New York Stock Exchange under the symbol "MWE." You can find more information about us at our Internet website, *www.markwest.com*. Our annual reports on Form 10-K, our quarterly reports on Form 10-Q, our current reports on Form 8-K and any amendments to those reports are available free of charge on or through our Internet website as soon as reasonably practicable after we electronically file or furnish such material with the Securities and Exchange Commission. The filings are also available through the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 or by calling 1-800-SEC-0330. Also, these filings are available on the Internet website *www.sec.gov*.

ITEM 1A. Risk Factors

In addition to the other information set forth elsewhere in this Form 10-K, you should carefully consider the following factors when evaluating us.

Risks Inherent in Our Business

Our substantial debt and other financial obligations could impair our financial condition, results of operations and cash flows, and our ability to fulfill our debt obligations.

We have substantial indebtedness and other financial obligations. Subject to the restrictions governing our indebtedness and other financial obligations, including the indentures governing our outstanding notes, we may incur significant additional indebtedness and other financial obligations.

Our substantial indebtedness and other financial obligations could have important consequences. For example, they could:

- make it more difficult for us to satisfy our obligations with respect to our existing debt;
- impair our ability to obtain additional financings in the future for working capital, capital expenditures, acquisitions, or general partnership and other purposes;
- have a material adverse effect on us if we fail to comply with financial and restrictive covenants in our debt agreements, and an event of default occurs as a result of that failure that is not cured or waived;
- require us to dedicate a substantial portion of our cash flow to payments on our indebtedness and other financial obligations, thereby reducing the availability of our cash flow to fund working capital, capital expenditures, distributions and other general partnership requirements;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and

- place us at a competitive disadvantage compared to our competitors that have proportionately less debt.

Furthermore, these consequences could limit our ability, and the ability of our subsidiaries, to obtain future financings, make needed capital expenditures, withstand any future downturn in our business or the economy in general, conduct operations or otherwise take advantage of business opportunities that may arise.

Our obligations under our Credit Facility are secured by substantially all of our assets and guaranteed by all of our wholly-owned subsidiaries, including our operating company (please read Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—*Liquidity and Capital Resources*). Our Credit Facility contains covenants requiring us to maintain specified financial ratios and satisfy other financial conditions, which may limit our ability to grant liens on our assets, make or own certain investments, enter into any swap contracts other than in the ordinary course of business, merge, consolidate, or sell assets, incur indebtedness senior to the Credit Facility, make distributions on equity investments, and declare or make, directly or indirectly, any distribution on our common units. We may be unable to meet those ratios and conditions. Any future breach of any of these covenants or our failure to meet any of these ratios or conditions could result in a default under the terms of our Credit Facility, which could result in acceleration of our debt and other financial obligations. If we were unable to repay those amounts, the lenders could initiate a bankruptcy or liquidation proceeding, or proceed against the collateral.

Global economic conditions may have adverse impacts on our business and financial condition.

Changes in economic conditions could adversely affect our financial condition and results of operations. A number of economic factors, including, but not limited to, gross domestic product, consumer interest rates, strength of U.S. currency, consumer confidence and debt levels, retail trends, housing starts, sales of existing homes, the level of mortgage refinancing, inflation and foreign currency exchange rates, may generally affect our business. Recessionary economic cycles, higher unemployment rates, higher fuel and other energy costs, and higher tax rates may adversely affect demand for natural gas, NGLs and crude oil. Also, tightening of the capital markets could adversely impact our ability to execute our long term organic growth projects and meet obligations to our producer customers and limit our ability to otherwise take advantage of business opportunities or react to changing economic and business conditions. These factors could have a material adverse effect on our revenues, income from operations, cash flows and our quarterly distribution on the common units.

We may not have sufficient cash after the establishment of cash reserves and payment of our expenses to enable us to pay distributions at the current level.

The amount of cash we can distribute on our units depends principally on the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees we charge and the margins we realize for our services and sales;
- the prices of, level of production of, and demand for natural gas and NGLs;
- the relative prices of NGLs and crude oil, which impact the effectiveness of our hedging program;
- the volumes of natural gas we gather, process and transport;
- the level of our operating costs; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- our debt service requirements;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our debt agreements;
- restrictions contained in our joint venture agreements;
- the level of capital expenditures we make, including capital expenditures incurred in connection with our enhancement projects;
- the cost of acquisitions, if any; and
- the amount of cash reserves established by our general partner.

Unitholders should be aware that the amount of cash we have available for distribution depends primarily on our cash flow and not solely on profitability, which is affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and may not make cash distributions during periods when we record net income.

Our profitability and cash flows are affected by the volatility of NGL product and natural gas prices.

We are subject to significant risks associated with frequent and often substantial fluctuations in commodity prices. In the past, the prices of natural gas and NGLs have been volatile, and we expect this volatility to continue. The New York Mercantile Exchange ("NYMEX") daily settlement price of natural gas for the prompt month contract in 2009 ranged from a high of $6.07 per MMBtu to a low of $2.51 per MMBtu. In 2010, the same index ranged from a high of $6.01 per MMBtu to a low of $3.29 per MMBtu. Also as an example, the composite of the weighted monthly average NGLs price at our Appalachian facilities based on our average NGLs composition in 2009 ranged from a high of approximately $1.44 per gallon to a low of approximately $0.68 per gallon. In 2010, the same composite ranged from a high of approximately $1.55 per gallon to a low of approximately $1.11 per gallon. The markets and prices for natural gas and NGLs depend upon factors beyond our control. These factors include demand for oil, natural gas and NGLs, which fluctuate with changes in market and economic conditions and other factors, including:

- the level of domestic oil, natural gas and NGL production;
- demand for natural gas and NGL products in localized markets;
- changes in interstate pipeline gas quality specifications;
- imports of crude oil, natural gas and NGLs;
- seasonality;
- the condition of the U.S. economy;
- political conditions in other oil-producing and natural gas-producing countries; and
- government regulation, legislation and policies.

Our net operating margins under various types of commodity-based contracts are directly affected by changes in NGL product prices and natural gas prices, and thus are more sensitive to volatility in commodity prices than our fee-based contracts. Additionally, our purchase and resale of gas in the ordinary course of business exposes us to significant risk of volatility in gas prices due to the potential difference in the time of the purchases and sales, and the potential existence of a difference in the gas price associated with each transaction. Significant declines in commodity prices could have an adverse impact on cash flows from operations that could result in noncash impairments of long-lived assets, as well as other-than-temporary noncash impairments of our equity method investments.

Relative changes in NGL product and natural gas prices may adversely impact our results due to frac spread, natural gas and liquids exposure.

Under our keep-whole arrangements, our principal cost is delivering dry gas of an equivalent Btu content to replace Btus extracted from the gas stream in the form of NGLs, or consumed as fuel during processing. The spread between the NGL product sales price and the purchase price of natural gas with an equivalent Btu content is called the "frac spread." Generally, the frac spread and, consequently, the net operating margins are positive under these contracts. In the event natural gas becomes more expensive on a Btu equivalent basis than NGL products, the cost of keeping the producer "whole" results in operating losses.

Due to timing of gas purchases and liquid sales, direct exposure to changes in market prices of either gas or liquids can be created because there is no longer an offsetting purchase or sale that remains exposed to market pricing. Through our marketing and derivatives activity, direct exposure may occur naturally or we may choose direct price exposure to either gas or liquids when we favor that exposure over frac spread risk. Given that we have derivative positions, adverse movement in prices to the positions we have taken will negatively impact results.

Our commodity derivative activities may reduce our earnings, profitability and cash flows.

Our operations expose us to fluctuations in commodity prices. We utilize derivative financial instruments related to the future price of crude oil, natural gas and certain NGLs with the intent of reducing volatility in our cash flows due to fluctuations in commodity prices.

The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities. We have a policy to enter into derivative transactions related to only a portion of the volume of our expected production or fuel requirements and, as a result, we will continue to have direct commodity price exposure to the unhedged portion. Our actual future production or fuel requirements may be significantly higher or lower than we estimate at the time we enter into derivative transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to settle all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, which could result in a substantial diminution of our liquidity. Additionally, because we primarily use derivative financial instruments relating to the future price of crude oil to mitigate our exposure to NGL price risk, the volatility or our future cash flows and net income may increase if there is a change in the pricing relationship between crude oil and NGLs. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the downside volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, our hedging activities are subject to the risks that a counterparty may not perform its obligation under the applicable derivative instrument, the terms of the derivative instruments are imperfect, and our hedging policies and procedures are not properly followed. It is possible that the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved. For further information about our risk management policies and procedures, please read Note 6 of the accompanying Notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K.

We conduct risk management activities but we may not accurately predict future commodity price fluctuations and therefore expose us to financial risks and reduce our opportunity to benefit from price increases.

We evaluate our exposure to commodity price risk from an overall portfolio basis. We have discretion in determining whether and how to manage the commodity price risk associated with our physical and derivative positions.

To the extent that we do not manage the commodity price risk relating to a position that is subject to commodity price risk, and commodity prices move adversely, we could suffer losses. Such losses could be substantial, and could adversely affect our operations and cash flows available for distribution to our unitholders. In addition, managing the commodity risk may actually reduce our opportunity to benefit from increases in the market or spot prices.

The enactment of the Dodd-Frank Act could have an adverse impact on our ability to hedge risks associated with our business.

Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the OTC derivatives market and entities, such as us, that participate in that market. The new legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), was signed into law by the President on July 21, 2010 and requires the Commodities Futures Trading Commission (the "CFTC") and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In its rulemaking under the Dodd-Frank Act, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize these regulations. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Any of these consequences could have a material, adverse effect on our income from operations, cash flows and quarterly distribution to common unitholders.

A significant decrease in natural gas production in our areas of operation would reduce our ability to make distributions to our unitholders.

Our gathering systems are connected to natural gas reserves and wells, from which the production will naturally decline over time, which means that our cash flows associated with these wells will also decline over time. To maintain or increase throughput levels on our gathering systems and the utilization rate at our processing plants, treating facilities, and fractionation facilities, we must continually obtain new natural gas supplies. Our ability to obtain additional sources of natural gas depends in part on the level of successful drilling activity near our gathering systems.

We have no control over the level of drilling activity in the areas of our operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. In addition, we have no control over producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, drilling costs per mcf, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulations and the availability and cost of capital. In addition, fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity generally decreases as oil and natural gas prices decrease. During 2009, we saw decreases in the prices of natural gas and prices have remained at low levels since then. Declines in natural gas prices, if sustained, could lead to a material decrease in such production activity and ultimately to a decrease in drilling activity.

Because of these factors, even if new natural gas reserves are discovered in areas served by our assets, producers may choose not to develop those reserves. If we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells due to reductions in drilling activity or competition, throughput on our pipelines and the utilization rates of our facilities would decline, which could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions.

Alternative financing strategies may not be successful.

Periodically, we will consider the use of alternative financing strategies such as joint venture arrangements and the sale of non-strategic assets. Joint venture agreements may not share the risks and rewards of ownership in proportion to the voting interests. Joint venture arrangements may require us to pay certain costs or to make certain capital investments and we may have little control over the amount or the timing of these payments and investments. We may not be able to negotiate terms that adequately reimburse us for our costs to fulfill service obligations for those joint ventures where we are the operator. In addition, our joint venture partners may be unable to meet their economic or other obligations and we may be required to fulfill those obligations alone.

We may periodically sell assets or portions of our business. Separating the existing operations from our assets or operations of which we dispose may result in significant expense and accounting charges, disrupt our business or divert management's time and attention. We may not achieve expected cost savings from these dispositions or the proceeds from sales of assets or portions of our business may be lower than the net book value of the assets sold. We may not be relieved of all of our obligations related to the assets or businesses sold. These factors could have a material adverse effect on our revenues, income from operations, cash flows and our quarterly distribution on our common units.

We depend on third parties for the natural gas and refinery off-gas we process, and the NGLs we fractionate at our facilities, and a reduction in these quantities could reduce our revenues and cash flow.

Although we obtain our supply of natural gas, refinery off-gas and NGLs from numerous third-party producers, a significant portion comes from a limited number of key producers/suppliers who are committed to us under processing contracts. According to these contracts or other supply arrangements, however, the producers are usually under no obligation to deliver a specific quantity of natural gas or NGLs to our facilities. If these key suppliers, or a significant number of other producers, were to decrease the supply of natural gas or NGLs to our systems and facilities for any reason, we could experience difficulty in replacing those lost volumes. Because our operating costs are primarily fixed, a reduction in the volumes of natural gas or NGLs delivered to us would result not only in a reduction of revenues, but also a decline in net income and cash flow.

Growing our business by constructing new pipelines and processing and treating facilities subjects us to construction risks and risks that natural gas supplies will not be available upon completion of the facilities.

One of the ways we intend to grow our business is through the construction of additions to our existing gathering systems and construction of new gathering, treating, processing, and fractionation facilities. The construction of gathering, processing and treating facilities requires the expenditure of significant amounts of capital, which may exceed our expectations, and involves numerous regulatory, environmental, political, legal and inflationary uncertainties, which may delay our construction activities. If we undertake these projects, we may not be able to complete them on schedule or at all or at the budgeted cost. In addition, certain agreements with our producer customers contain substantial financial penalties and/or give the producer the right to repurchase certain assets if construction deadlines are not achieved. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new pipeline, the construction will occur over an extended period of time, and we will not receive any material increases in revenues until after completion of the project, if at all.

Furthermore, we may have only limited natural gas supplies committed to these facilities prior to their construction. Moreover, we may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. We may also rely on estimates of proved reserves in our decision to construct new pipelines and facilities, which may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of proved reserves. As a result, new facilities may not be able to attract enough natural gas to achieve our expected investment return, which could adversely affect our operations and cash flows available for distribution to our unitholders.

The fees charged to third parties under our gathering, processing, transmission, transportation, fractionation and storage agreements may not escalate sufficiently to cover increases in costs, or the agreements may not be renewed or may be suspended in some circumstances.

Our costs may increase at a rate greater than the fees we charge to third parties. Furthermore, third parties may not renew their contracts with us. Additionally, some third parties' obligations under their agreements with us may be permanently or temporarily reduced due to certain events, some of which are beyond our control, including force majeure events wherein the supply of either natural gas, NGLs or crude oil are curtailed or cut off. Force majeure events include (but are not limited to): revolutions, wars, acts of enemies, embargoes, import or export restrictions, strikes, lockouts, fires, storms, floods, acts of God, explosions and mechanical or physical failures of equipment affecting our facilities or facilities of third parties. If the escalation of fees is insufficient to cover increased costs, if third parties do not renew or extend their contracts with us or if third parties suspend or terminate their contracts with us, our financial results would suffer.

We are exposed to the credit risks of our key customers and derivative counterparties, and any material nonpayment or nonperformance by our key customers or derivative counterparties could reduce our ability to make distributions to our unitholders.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. The prevailing economic uncertainty may increase this risk. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. In addition, our hedging activities are subject to the risks that a counterparty may not perform its obligation under the applicable derivative instrument, the terms of the derivative instruments are imperfect, and our hedging policies and procedures are not properly followed. Any material nonpayment or nonperformance by our key customers or our derivative counterparties could reduce our ability to make distributions to our unitholders.

We may not be able to retain existing customers, or acquire new customers, which would reduce our revenues and limit our future profitability.

The renewal or replacement of existing contracts with our customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond our control, including competition from other gatherers, processors, pipelines, fractionators, and the price of, and demand for, natural gas, NGLs and crude oil in the markets we serve. Our competitors include large oil, natural gas, refining and petrochemical companies, some of which have greater financial resources, more numerous or greater capacity pipelines, processing and other facilities, and greater access to natural gas and NGL supplies than we do. Additionally, our customers that gather gas through facilities that are not otherwise dedicated to us may develop their own processing and fractionation facilities in lieu of using our services. Certain of our competitors may also have advantages in competing for acquisitions, or other new business opportunities, because of their financial resources and synergies in operations.

As a consequence of the increase in competition in the industry, and the volatility of natural gas prices, end-users and utilities are reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternative fuels in response to relative price fluctuations in the market. Because there are numerous companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in the end-user and utilities markets primarily on the basis of price. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could affect our profitability. For more information regarding our competition, please read Item 1. Business—*Competition* of Part I of this report.

Transportation on certain of our pipelines may be subject to federal or state rate and service regulation, and the imposition and/or cost of compliance with such regulation could adversely affect our operations and cash flows available for distribution to our unitholders.

Some of our gas, liquids and crude oil transmission operations are subject to rate and service regulations by FERC or various state regulatory bodies, depending upon jurisdiction. FERC generally regulates the transportation of natural gas and oil in interstate commerce, and FERC's regulatory authority includes: facilities construction, acquisition, extension or abandonment of services or facilities; accounts and records; and depreciation and amortization policies. FERC's action in any of these areas or modifications of its current regulations can adversely impact our ability to compete for business, the costs we incur in our operations, the construction of new facilities or our ability to recover the full cost of operating our pipelines. We also own pipelines that carry NGLs across state lines. We are the only shipper on these pipelines and do not operate these pipelines as a common carrier, or hold them out for service to the public. We will also construct additional NGL pipelines that will be operated in a similar manner. The likelihood of third-party entities seeking to utilize our NGL pipelines is remote; therefore, we believe these pipelines should not be subject to FERC regulation in the future or that they should qualify for a waiver from FERC's jurisdiction. However we cannot provide assurance that FERC will not at some point assert that some or all of such transportation is within its jurisdiction. If FERC were successful with any such assertion, FERC's rate-making methodologies may subject us to potentially burdensome and expensive operational, reporting and other requirements.

Intrastate natural gas pipeline operations and transportation on proprietary natural gas or petroleum products pipelines are generally not subject to regulation by FERC, and the Natural Gas Act, which is referred to as "NGA," specifically exempts some gathering systems. Yet such operations may still be subject to regulation by various state agencies. The applicable statutes and regulations generally require that our rates and terms and conditions of service provide no more than a fair return on the aggregate value of the facilities used to render services. We cannot assure unitholders that FERC will not at some point determine that such gathering and transportation services are within its jurisdiction, and regulate such services, which could limit the rates that we may charge and increase our costs of operation. FERC rate cases can involve complex and expensive proceedings. For more information regarding regulatory matters that could affect our business, please read Item 1. Business—*Regulatory Matters* as set forth in this report.

Some of our natural gas and crude oil transportation operations are subject to FERC's rate-making policies that could have an adverse impact on our ability to establish rates that would allow us to recover the full cost of operating our pipelines including a reasonable return.

Action by FERC on currently pending matters as well as matters arising in the future could adversely affect our ability to establish reasonable rates that cover operating costs and allow for a reasonable return. An adverse determination in any future rate proceeding brought by or against us could have a material adverse effect on our business, financial condition and results of operations.

For example, one such matter relates to FERC's policy regarding allowances for income taxes in determining a regulated entity's cost of service. In May 2005, FERC adopted a policy statement ("Policy Statement"), stating that it would permit entities owning public utility assets, including oil pipelines, to include an income tax allowance in such utilities' cost-of-service rates to reflect actual or potential tax liability attributable to their public utility income, regardless of the form of ownership. Pursuant to the Policy Statement, a tax pass-through entity seeking such an income tax allowance would have to establish that its partners or members have an actual or potential income tax obligation on the entity's public utility income. This tax allowance policy was upheld by the D.C. Circuit in May 2007. Whether a pipeline's owners have actual or potential income tax liability will be reviewed by FERC on a case-by-case basis. How the Policy Statement is applied in practice to pipelines owned by publicly traded partnerships could impose limits on our ability to include a full income tax allowance in cost of service.

If we are unable to obtain new rights-of-way or other property rights, or the cost of renewing existing rights-of-way or property rights increases, then we may be unable to fully execute our growth strategy, which may adversely affect our operations and cash flows available for distribution to unitholders.

The construction of additions to our existing gathering assets and the expansion of our gathering, processing and fractionation assets may require us to obtain new rights-of-way or other property rights prior to constructing new plants, pipelines and other transportation facilities. We may be unable to obtain such rights-of-way or other property rights to connect new natural gas supplies to our existing gathering lines, to connect our existing or future facilities to new natural gas or natural gas liquids markets, or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or other property rights or to renew existing rights-of-way or property rights. If the cost of obtaining new or renewing existing rights-of-way or other property rights increases, it may adversely affect our operations and cash flows available for distribution to unitholders.

We are indemnified for liabilities arising from an ongoing remediation of property on which certain of our facilities are located and our results of operation and our ability to make distributions to our unitholders could be adversely affected if the indemnifying party fails to perform its indemnification obligation.

Columbia Gas is the previous or current owner of the property on which our Kenova, Boldman, Cobb, Kermit and Majorsville facilities are located and is the previous operator of our Boldman and Cobb facilities. Columbia Gas has been or is currently involved in investigatory or remedial activities with respect to the real property underlying the Boldman, Cobb and Majorsville facilities pursuant to an "Administrative Order by Consent for Removal Actions" entered into by Columbia Gas and the U.S. Environmental Protection Agency and, in the case of the Boldman facility, an "Agreed Order" with the Kentucky Natural Resources and Environmental Protection Cabinet.

Columbia Gas has agreed to retain sole liability and responsibility for, and to indemnify us against, any environmental liabilities associated with these regulatory orders or the real property underlying these facilities to the extent such liabilities arose prior to the effective date of the agreements pursuant to which such properties were acquired or leased from Columbia Gas. Our results of operation and our ability to make cash distributions to our unitholders could be adversely affected if in the future Columbia Gas fails to perform under the indemnification provisions of which we are the beneficiary.

Our business is subject to federal, state and local laws and regulations with respect to environmental, safety and other regulatory matters, and the violation of, or the cost of compliance with, such laws and regulations could adversely affect our operations and cash flows available for distribution to our unitholders.

Numerous governmental agencies enforce comprehensive and stringent federal, state, regional and local laws and regulations on a wide range of environmental, safety and other regulatory matters. We could be adversely affected by increased costs due to stricter pollution-control requirements or liabilities resulting from non-compliance with operating or other regulatory permits. Strict and, under certain circumstances, joint and several liability may be incurred without regard to fault, or the legality of the original conduct, under certain of the environmental laws for remediation of contaminated areas, including the Comprehensive Environmental Response, Compensation and Liability Act, as amended, the Resource Conservation and Recovery Act, as amended, and analogous state laws. Private parties, including the owners of properties located near our storage, fractionation and processing facilities or through which our pipeline systems pass, also may have the right to pursue legal actions to enforce compliance, as well as seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. New, more stringent environmental laws, regulations and enforcement policies might adversely influence our products and activities, and existing laws, regulations and policies could be reinterpreted or modified to impose additional requirements, delays or constraints on our construction of facilities or on our operations, which requirements may include more stringent permitting requirements if our facilities are co-located for permitting purposes or the use of certain types of pollution-control equipment for emissions purposes that may increase our costs. Federal, state and local agencies also could impose additional safety requirements, any of which could affect our profitability. Local governments may adopt more stringent local permitting and zoning ordinances that impose additional requirements, delays or constraints on our activities to construct and operate our facilities, require the relocation of our facilities or increase our costs to construct and operate our facilities, including the construction of sound mitigation facilities. In addition, we face the risk of accidental releases or spills associated with our operations. These could result in material costs and liabilities, including those relating to claims for damages to property, natural resources and persons, environmental remediation and restoration costs, and governmental fines and penalties. Our failure to comply with environmental or safety-related laws and regulations could result in administrative, civil and criminal penalties, the imposition of investigatory and remedial obligations and even injunctions that restrict or prohibit some or all of our operations. For more information regarding the environmental, safety and other regulatory matters that could affect our business, please read Item 1. Business—*Regulatory Matters*, Item 1. Business—*Environmental Matters*, and Item 1. Business—*Pipeline Safety Regulations*, each as set forth in this report.

The adoption of legislation by Congress or states, or additional regulations by the EPA, to control and reduce the emissions of greenhouse gases could increase our operating costs and adversely affect the cash flows available for distribution to our unitholders.

As a consequence to an EPA administrative conclusion that GHGs present an endangerment to public heath and the environment, the EPA has adopted regulations that require a reduction in emissions of GHGs from motor vehicles and also may trigger PSD and Title V permit requirements for GHG emissions from certain stationary sources when the motor vehicle standards took effect on January 2, 2011. The EPA rules have tailored the PSD and Title V permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. On October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including natural gas liquids fractionators, beginning in 2011 for emissions occurring in 2010 and, on

November 30, 2010, the EPA published a final rule expanding this GHG emissions reporting rule to include onshore and offshore oil and natural gas production and onshore oil and natural gas processing, transmission, storage, and distribution activities beginning in 2012 for emissions occurring in 2011. In addition, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. As a result of these requirements—all of which are currently subject to judicial review in the Court of Appeals for the District of Columbia—or the adoption of any new legislation or regulations that requires additional reporting, monitoring or recordkeeping of GHGs, or otherwise limits emissions of GHGs from our equipment and operations, could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities, could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we process or fractionate. For more information regarding greenhouse gas emission and regulation, please read Item 1. Business—*Environmental Matters—Air and Greenhouse Gases*. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our assets and operations.

Federal legislation and state legislative and regulatory initiatives relating to hydraulic fracturing could result in reduced volumes available for us to gather, process and fractionate.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations such as shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012, and a committee of the U.S. House of Representatives is conducting an investigation of hydraulic fracturing practices. In addition, legislation was proposed in the recently completed session of Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process, and such legislation could be introduced in the current session of Congress. Moreover, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. If new federal or state laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could make it more difficult to complete natural gas wells in shale formations and increase our producers' costs of compliance. This could significantly reduce the volumes that we gather, process and fractionate which could adversely impact our earnings, profitability and cash flows.

The amount of gas we process, gather and transmit, or the NGLs and crude oil we gather and transport, may be reduced if the pipelines to which we deliver the natural gas, NGLs, or crude oil cannot, or will not, accept the gas, NGLs or crude oil.

All of the natural gas we process, gather and transmit is delivered into pipelines for further delivery to end-users. If these pipelines cannot, or will not, accept delivery of the gas due to downstream constraints on the pipeline or changes in interstate pipeline gas quality specifications, we will be forced to limit or stop the flow of gas through our pipelines and processing systems. In addition, interruption of pipeline service upstream of our processing facilities would limit or stop flow through our processing facilities. Likewise, if the pipelines into which we deliver NGLs or crude oil are interrupted, we will be limited in, or prevented from conducting, our crude oil transportation operations. Any number of factors beyond our control could cause such interruptions or constraints on pipeline service, including necessary and scheduled maintenance, or unexpected damage to the pipeline. Because our revenues and net operating margins depend upon (1) the volumes of natural gas we process, gather and transmit, (2) the throughput of NGLs through our transportation, fractionation and storage facilities and (3) the volume of crude oil we gather and transport, any reduction of volumes could adversely affect our operations and cash flows available for distribution to our unitholders.

Interruptions in operations at any of our facilities may adversely affect our operations and cash flows available for distribution to our unitholders.

Our operations depend upon the infrastructure that we have developed, including processing and fractionation plants, storage facilities, and various means of transportation. Any significant interruption at these facilities or pipelines, or our inability to transmit natural gas or NGLs, or to transport crude oil to or from these facilities or pipelines for any reason, would adversely affect our operations and cash flows available for distribution to our unitholders.

Operations at our facilities could be partially or completely shut down, temporarily or permanently, as the result of circumstances not within our control, such as:

- unscheduled turnarounds or catastrophic events at our physical plants or facilities;
- restrictions imposed by governmental authorities or court proceedings;
- labor difficulties that result in a work stoppage or slowdown; and
- a disruption in the supply of crude oil to our crude oil pipeline, natural gas to our processing plants or gathering pipelines, or a disruption in the supply of NGLs to our transportation pipeline and fractionation facility.

Due to our lack of asset diversification, adverse developments in our gathering, processing, transportation, transmission, fractionation and storage businesses could reduce our operations and cash flows available for distribution to our unitholders.

We rely exclusively on the revenues generated from our gathering, processing, transportation, transmission, fractionation and storage businesses. An adverse development in one of these businesses would have a significantly greater impact on our operations and cash flows available for distribution to our unitholders than if we maintained more diverse assets.

We may not be able to successfully execute our business plan and may not be able to grow our business, which could adversely affect our operations and cash flows available for distribution to our unitholders.

Our ability to successfully operate our business, generate sufficient cash to pay the quarterly cash distributions to our unitholders, and to allow for growth, is subject to a number of risks and uncertainties. Similarly, we may not be able to successfully expand our business through acquiring or growing our assets, because of various factors, including economic and competitive factors beyond our control. If we are unable to grow our business, or execute on our business plan including increasing or maintaining distributions, the market price of the common units is likely to decline.

We are subject to operating and litigation risks that may not be covered by insurance.

Our industry is subject to numerous operating hazards and risks incidental to processing, transporting, fractionating and storing natural gas and NGLs and to transporting and storing crude oil. These include:

- damage to pipelines, plants, related equipment and surrounding properties caused by floods, hurricanes, and other natural disasters and acts of terrorism;
- inadvertent damage from construction and farm equipment;
- leakage of crude oil, natural gas, NGLs and other hydrocarbons;
- fires and explosions; and
- other hazards and conditions, including those associated with various hazardous pollutant emissions, high-sulfur content, or sour gas, and proximity to businesses. Homes, or other populated areas, that could also result in personal injury and loss of life, pollution and suspension of operations.

As a result, we may be a defendant in various legal proceedings and litigation arising from our operations. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. Market conditions could cause certain insurance premiums and deductibles to become unavailable, or available only for reduced amounts of coverage. For example, insurance carriers now require broad exclusions for losses due to war risk and terrorist acts. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our operations and cash flows available for distribution to our unitholders.

Our business may suffer if any of our key senior executives or other key employees discontinues employment with us or if we are unable to recruit and retain highly skilled staff.

Our future success depends to a large extent on the services of our key employees. Our business depends on our continuing ability to recruit, train and retain highly qualified employees, including accounting, business operations, finance and other key back-office and mid-office personnel. The competition for these employees is intense, and the loss of these employees could harm our business. Our equity based long-term incentive plans are a significant component of our strategy to retain key employees. Further, our ability to successfully integrate acquired companies or handle complexities related to managing joint ventures depends in part on our ability to retain key management and existing employees at the time of the acquisition.

A shortage of skilled labor may make it difficult for us to maintain labor productivity, and competitive costs could adversely affect our operations and cash flows available for distribution to our unitholders.

Our operations require skilled and experienced laborers with proficiency in multiple tasks. In recent years, a shortage of workers trained in various skills associated with the midstream energy business has caused us to conduct certain operations without full staff, which decreases our productivity and increases our costs. This shortage of trained workers is the result of the previous generation's experienced workers reaching the age for retirement, combined with the difficulty of attracting new laborers to the midstream energy industry. Thus, this shortage of skilled labor could continue over an extended period. If the shortage of experienced labor continues or worsens, it could have an adverse impact on our labor productivity and costs and our ability to expand production in the event there is an increase in the demand for our products and services, which could adversely affect our operations and cash flows available for distribution to our unitholders.

If we do not make acquisitions on economically acceptable terms, our future growth may be limited.

Our ability to grow depends in part on our ability to make acquisitions that result in an increase in the cash generated from operations per unit. If we are unable to make these accretive acquisitions because we are (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms, or (3) outbid by competitors, then our future growth and ability to increase distributions will be limited.

If we are unable to timely and successfully integrate our future acquisitions, our future financial performance may suffer, and we may fail to realize all of the anticipated benefits of the transaction.

Our future growth will depend in part on our ability to integrate our future acquisitions. We cannot guarantee that we will successfully integrate any acquisitions into our existing operations, or that we will achieve the desired profitability and anticipated results from such acquisitions. Failure to achieve such planned results could adversely affect our operations and cash flows available for distribution to our unitholders.

The integration of acquisitions with our existing business involves numerous risks, including:

- operating a significantly larger combined organization and integrating additional midstream operations into our existing operations;
- difficulties in the assimilation of the assets and operations of the acquired businesses, especially if the assets acquired are in a new business segment or geographical area;
- the loss of customers or key employees from the acquired businesses;
- the diversion of management's attention from other existing business concerns;
- the failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities;
- integrating personnel from diverse business backgrounds and organizational cultures; and
- consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. Following an acquisition, we may discover previously unknown liabilities including those under the same stringent environmental laws and regulations relating to releases of pollutants into the environment and environmental protection as are applicable to our existing plants, pipelines and facilities. If so, our operation of these new assets could cause us to incur increased costs to address these liabilities or to attain or maintain compliance with such requirements. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

We have partial ownership interests in a number of joint venture legal entities, including Liberty, Pioneer, Bright Star, Wirth, and Centrahoma, which could adversely affect our ability to control certain decisions of these entities. In addition, we may be unable to control the amount of cash we will receive from the operation of these entities and where we do not have control, we could be required to contribute significant cash to fund our share of their operations, which could adversely affect our ability to distribute cash to our unitholders.

Our inability, or limited ability, to control certain aspects of management of joint venture legal entities that we have a partial ownership interest in may mean that we will not receive the amount of cash we expect to be distributed to us. In addition, for entities where we have a non-controlling ownership interest such as in Centrahoma we will be unable to control ongoing operational decisions, including the incurrence of capital expenditures that we may be required to fund. Specifically,

- We may have limited ability to influence certain management decisions with respect to these entities and their subsidiaries, including decisions with respect to incurrence of expenses and distributions to us;
- These entities may establish reserves for working capital, capital projects, environmental matters and legal proceedings which would otherwise reduce cash available for distribution to us;
- These entities may incur additional indebtedness, and principal and interest made on such indebtedness may reduce cash otherwise available for distribution to us; and
- These entities may require us to make additional capital contributions to fund working capital and capital expenditures, our funding of which could reduce the amount of cash otherwise available for distribution.

All of these things could significantly and adversely impact our ability to distribute cash to our unitholders.

Certain changes in accounting and/or financial reporting standards issued by the FASB, the SEC or other standard-setting bodies could have a material adverse impact on our financial position or results of operations.

We are subject to the application of GAAP, which periodically is revised and/or expanded. As such, we periodically are required to adopt new or revised accounting and/or financial reporting standards issued by recognized accounting standard setters or regulators, including the FASB and the SEC. It is possible that future requirements, including the proposed implementation of, or convergence with, International Financial Reporting Standards ("IFRS"), could change our current application of GAAP, resulting in a material adverse impact on our financial position or results of operations.

The potential requirement to convert our financial statements from being prepared in conformity with GAAP to IFRS may strain our resources and increase our annual expenses.

The SEC may require in the future that we report our financial results under IFRS instead of GAAP. IFRS is a set of accounting principles that has been gaining acceptance on a worldwide basis. These standards are published by the London-based International Accounting Standards Board and are more focused on objectives and principles and less reliant on detailed rules than GAAP. Today, there remain significant and material differences in several key areas between GAAP and IFRS which would affect us. Additionally, GAAP provides specific guidance in classes of accounting transactions for which equivalent guidance in IFRS does not exist. The adoption of IFRS is highly complex and would have an impact on many aspects and operations of us, including but not limited to financial accounting and reporting systems, internal controls, taxes, borrowing covenants and cash management. It is expected that a significant amount of time, internal and external resources and expenses over a multi-year period would be required for this conversion.

Risks Related to Our Partnership Structure

We may issue additional common units without unitholder approval, which would dilute current unitholder ownership interests.

The General Partner, without your approval, may cause us to issue additional common units or other equity securities of equal rank with or senior to the common units.

The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- the unitholders' proportionate ownership interest will decrease;
- the amount of cash available for distribution on each common unit may decrease;
- the relative voting strength of each previously outstanding common unit may be diminished;
- the market price of the common units may decline; and
- the ratio of taxable income to distributions may increase.

Unitholders have less ability to influence management's decisions than holders of common stock in a corporation.

Unlike the holders of common stock in a corporation, unitholders have more limited voting rights on matters affecting our business, and therefore a more limited ability to influence management's decisions regarding our business. The amended and restated partnership agreement provides that the General Partner may not withdraw and may not be removed at any time for any reason whatsoever. Furthermore, if any person or group other than the General Partner and its affiliates acquires beneficial ownership of 20% or more of any class of units (without the prior approval of the General Partner board), that person or group loses voting rights on all of its units. However, if unitholders are dissatisfied with the performance of our General Partner, they have the right to annually elect its board of directors.

Unitholders may not have limited liability if a court finds that unitholder action constitutes control of our business.

Under Delaware law, unitholders could be held liable for our obligations as a general partner if a court determined that the right or the exercise of the right by unitholders as a group to approve certain transactions or amendments to the agreement of limited partnership, or to take other action under the Partnership Agreement was considered participation in the "control" of our business. Unitholders elect the members of the General Partner board, which may be deemed to be participation in the "control" of our business. This could subject unitholders to liability as a general partner.

In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that, under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

Tax Risks Related to Owning our Common Units

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the Internal Revenue Service ("IRS") were to treat us as a corporation for federal income tax purposes or we were to become subject to a material amount of entity-level taxation then our cash available for distribution to unitholders could be substantially reduced.

The anticipated after-tax benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based on our current operations that we are so treated, a change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, our treatment as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of the common units.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to entity-level taxation. The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by legislative, judicial, or administrative changes and differing interpretations at any time. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. For example, members of Congress have considered substantive changes to the existing U.S. tax laws that would have affected certain publicly traded partnerships. Although the proposed legislation would not have appeared to affect our tax treatment as a partnership, we are unable to predict whether any of these changes, or other proposals, will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

The partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution amount and the target distribution amounts will be reduced to reflect the impact of that law on us.

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution to unitholders.

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution to our unitholders. For example, the state of Texas and the state of Michigan have both instituted income-based taxes that result in an entity level tax for us. We are required to pay a Texas franchise tax at a maximum effective rate of 0.7% of our gross income apportioned to Texas in the prior year. Additionally, the Michigan Business Tax, which contains two prongs, also imposes a tax on us. The two prongs comprise a tax at the rate of 0.8% of a taxpayer's modified gross receipts and a tax at the rate of 4.95% of the taxpayer's business income. Each of the above mentioned rates also includes a surcharge of 21.99% resulting in overall rates of 0.97% and 6.03%. The imposition of entity level taxes on us by any other state will reduce the cash available for distribution to our unitholders.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and the General Partner because the costs will reduce our cash available for distribution.

A unitholder may be required to pay taxes on his share of our income even if the unitholder does not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, each unitholder will be required to pay any federal income taxes and, in some cases, state and local income taxes on his share of our taxable income even if the unitholder receives no cash distributions from us. A unitholder may not receive cash distributions from us equal to his share of our taxable income or even equal to the actual tax liability that results from that income.

Tax gain or loss on the disposition of our common units could be more or less than expected.

If a unitholder sells his common units, he will recognize a gain or loss equal to the difference between the amount realized and his tax basis in those common units. Because distributions in excess of the unitholder's allocable share of our net taxable income decrease the unitholder's tax basis in his common units, the amount, if any, of such prior excess distributions with respect to the common units the unitholder sells will, in effect, become taxable income to the unitholder if the unitholder sells such common units at a price greater than his tax basis in those common units, even if the price the unitholder receives is less than his original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if a unitholder sells common units, the unitholder may incur a tax liability in excess of the amount of cash the unitholder receives from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and could be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable tax rate, and non-U.S. persons will be required to file federal tax returns and pay tax on their share of our taxable income. If a unitholder is a tax exempt entity or a non-U.S. person, the unitholder should consult a tax advisor before investing in our common units.

We treat each purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of our common units.

To maintain the uniformity of the economic and tax characteristics of our common units, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from a unitholder's sale of our common units and could have a negative impact on the value of our common units or result in audit adjustments to a unitholder's tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of the common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of the units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. Recently, however, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of those common units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from lending their common units.

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

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

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

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have technically terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in our filing two tax returns for one fiscal year and may result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but would result in our being treated as a new partnership for tax purposes. If we were treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we were unable to determine that a termination occurred. The IRS has recently announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the tax years in which the termination occurs.

Our unitholders will likely be subject to state and local taxes and return filing requirements in states where the unitholders do not live as a result of investing in common units.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if our unitholders do not live in any of those jurisdictions. Our unitholders will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently do business or own property in nine states, most of which, other than Texas, impose personal income taxes. Most of these states also impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is our unitholder's responsibility to file all United States federal, foreign, state and local tax returns.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 2. Properties

The following tables set forth certain information relating to our gas processing facilities, fractionation facility, natural gas gathering systems, NGL pipelines, natural gas pipeline and crude oil pipeline as of and for the year ended December 31, 2010.

Gas Processing Facilities:

Facility	Location	Year of Initial Construction	Design Throughput Capacity	Year ended December 31, 2010		
				Natural Gas Throughput	Utilization of Design Capacity	NGL Throughput
			(Mcf/d)	(Mcf/d)		(Gal/d)
Southwest						
East Texas:						
East Texas processing plant	Panola County, TX	2005	280,000	233,100	83%	673,400
Oklahoma:						
Arapaho processing plants	Custer County, OK	2000	160,000	131,200	82%	367,400
Northeast						
Appalachia:						
Kenova processing plant(1)	Wayne County, WV	1996	160,000	114,600	72%	230,300
Boldman processing plant(1)	Pike County, KY	1991	70,000	43,700	62%	46,700
Cobb processing plant	Kanawha County, WV	2005	65,000	30,400	47%	65,100
Kermit processing plant(1)(2)	Mingo County, WV	2001	32,000	N/A	N/A	N/A
Liberty(3)						
Marcellus Shale:						
Houston processing plants	Washington County, PA	2009	155,000	122,300	79%	287,600
Majorsville processing plant(4)	Marshall County, WV	2010	135,000	93,400	69%	162,600
Gulf Coast						
Javelina processing plant	Corpus Christi, TX	1989	142,000	118,600	84%	946,600

(1) A portion of the gas processed at the Boldman plant, and all of the gas processed at the Kermit plant, is further processed at the Kenova plant to recover additional NGLs.

(2) The Kermit processing plant is operated by a third party solely to prevent liquids from condensing in the gathering and transmission pipelines upstream of our Kenova plant. We do not receive Kermit gas volume information but do receive all of the liquids produced at the Kermit facility.

(3) The Liberty assets are owned by a joint venture with M&R. One of our wholly-owned subsidiaries serves as the operator (see Note 4 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K).

(4) The Majorsville processing plant was placed into service in September 2010. The volume reported is the average daily rate for the days of operation.

The table above does not include the 100 MMcf/d cryogenic processing plant and the 75 MMcf/d mechanical refrigeration processing plant acquired on February 1, 2011 as part of the Langley Acquisition discussed in Item 1 of this Form 10-K.

Fractionation Facility:

Facility	Location	Year of Initial Construction	Design Throughput Capacity (Gal/d)	Year ended December 31, 2010 NGL Throughput (Gal/d)	Year ended December 31, 2010 Utilization of Design Capacity
Northeast					
Appalachia:					
Siloam fractionation plant .	South Shore, KY	1957	1,008,000	871,100	86%
Liberty					
Houston:					
Depropanizer (partial fractionation)(5)	Washington County, PA	2009	1,131,900	174,000	15%

(5) The Houston depropanizer volume is the full-year average for 2010. In October 2010 the capacity increased 672,000 Gal/d as a result of the Majorsville depropanizer being place in service. The calculated utilization is based on the capacity that existed throughout the year. Utilization for October through December 2010 was approximately 23%.

Our Siloam facility has both above ground, pressurized storage facilities, with usable capacity of two million gallons, and underground storage facilities, with usable capacity of ten million gallons. Product can be received by truck, pipeline or rail car and can be transported from the facility by truck, rail car or barge. There are ten automated 24-hour-a-day truck loading and unloading slots, a rail loading/unloading rack with 14 unloading slots, and a river barge facility capable of loading barges with a capacity of up to 840,000 gallons.

Natural Gas Gathering Systems:

Facility	Location	Year of Initial Construction	Design Throughput Capacity	Year ended December 31, 2010	
				Natural Gas Throughput	Utilization of Design Capacity
			(Mcf/d)	(Mcf/d)	
Southwest					
East Texas:					
East Texas gathering system	Panola County, TX	1990	500,000	430,300	86%
Oklahoma:					
Foss Lake gathering system	Roger Mills, Ellis and Custer Counties, OK	1998	130,000	71,100	55%
Stiles Ranch gathering system	Wheeler County, TX	2008	250,000	112,300	45%
Grimes gathering system . .	Beckham and Roger Mills Counties, OK	2005	25,000	7,700	31%
Southeast Oklahoma gathering system	Hughes, Pittsburg and Coal Counties, OK	2006	550,000	521,400	95%
Other Southwest:					
Appleby gathering system . .	Nacogdoches County, TX	1990	85,000	31,600	37%
Other gathering systems(6) .	Various	Various	36,500	7,900	22%
Liberty					
Marcellus Shale:					
Gas gathering system	Washington County, PA	2008	240,000	142,200	59%

(6) Excludes lateral pipelines where revenue is not based on throughput.

NGL Pipelines:

Pipeline	Location	Year of Initial Construction	Design Throughput Capacity (Gal/d)	Year ended December 31, 2010 NGL Throughput (Gal/d)	Year ended December 31, 2010 Utilization of Design Capacity
Northeast					
Appalachia:					
Ranger to Kenova(7) . . .	Lincoln County, WV to Wayne County, WV	1976	831,000	326,700	39%
Kenova to Siloam(7)	Wayne County, WV to South Shore, KY	1957	831,000	557,000	67%
Southwest					
East Texas:					
East Texas liquid line . . .	Panola County, TX	2005	1,050,000	673,400	64%
Liberty					
Marcellus Shale:					
Majorsville to Houston(8)	Washington County, PA	2010	1,821,600	162,600	9%

(7) NGLs transported through the Ranger to Kenova pipeline are combined with NGLs recovered at the Kenova facility. The volume reported for the Kenova to Siloam pipeline represents the combined NGL stream.

(8) The Majorsville to Houston pipeline was placed into service in September 2010. The volume reported is for the days of operation.

Natural Gas Pipeline:

Pipeline	Location	Year of Initial Construction	Design Throughput Capacity (Dth/d)	Natural Gas Throughput (Dth/d)	Year ended December 31, 2010 Utilization of Design Capacity
Southwest					
Oklahoma					
Arkoma Connector Pipeline(9) . . .	Coal County, OK to Bryan County, OK	2009	638,000	377,000	59%

(9) The Arkoma Connector Pipeline is a joint venture with Arkoma Pipeline Partners, LLC ("ArcLight"), an affiliate of ArcLight Capital Partners, LLC. One of our wholly-owned subsidiaries serves as the operator (see Note 4 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K).

Crude Oil Pipeline:

Pipeline	Location	Year of Initial Construction	Design Throughput Capacity	NGL Throughput	Year ended December 31, 2010 Utilization of Design Capacity
			(Bbl/d)	(Bbl/d)	
Northeast					
Michigan:					
Michigan crude pipeline . . .	Manistee County, MI to Crawford County, MI	1973	60,000	12,800	21%

Title to Properties

Substantially all of our pipelines are constructed on rights-of-way granted by the owners of record of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where determined necessary, permits, leases, license agreements and franchise ordinances from public authorities to cross over or under, or to lay facilities in or along water courses, county roads, municipal streets and state highways, as applicable. We also have obtained easements and license agreements from railroad companies to cross over or under railroad properties or rights-of-way. Many of these authorizations and grants are revocable at the election of the grantor. In some cases, property on which our pipelines were built was purchased in fee or held under long-term leases. Our Siloam fractionation plant, Kenova processing plant and Houston processing facilities are on land that we own in fee.

Some of the leases, easements, rights-of-way, permits, licenses and franchise ordinances that were transferred to us required the consent of the then-current landowner to transfer these rights, which in some instances was a governmental entity. We believe that we have obtained sufficient third-party consents, permits and authorizations for the transfer of the assets necessary for us to operate our business. We also believe we have satisfactory title or other right to all of our material land assets. Title to these properties is subject to encumbrances in some cases; however, we believe that none of these burdens will materially detract from the value of these properties or from our interest in these properties, or will materially interfere with their use in the operation of our business.

We have pledged substantially all of our assets and those of our wholly-owned subsidiaries as collateral for borrowings under our credit agreement entered into on February 20, 2008, as amended and restated in July 2010.

ITEM 3. Legal Proceedings

We are subject to a variety of risks and disputes, and are a party to various legal proceedings in the normal course of our business. We maintain insurance policies in amounts and with coverage and deductibles as we believe reasonable and prudent. However, we cannot assure that the insurance companies will promptly honor their policy obligations or that the coverage or levels of insurance will be adequate to protect us from all material expenses related to future claims for property loss or business interruption to us, or for third-party claims of personal and property damage, or that the coverages or levels of insurance we currently have will be available in the future at economical prices. While it is not possible to predict the outcome of the legal actions with certainty, management is of the opinion that appropriate provisions and accruals for potential losses associated with all legal actions have been made in the consolidated financial statements.

In June 2006, the Office of Pipeline Safety ("OPS") issued a Notice of Probable Violation and Proposed Civil Penalty ("NOPV") (CPF No. 2-2006-5001) to both MarkWest Hydrocarbon and

Equitable Production Company ("Equitable"). The NOPV is associated with the pipeline leak and an ensuing explosion and fire that occurred on November 8, 2004 in Ivel, Kentucky on an NGL pipeline owned by Equitable and leased and operated by a subsidiary of the Partnership, MarkWest Energy Appalachia, L.L.C. The NOPV sets forth six counts of violations of applicable regulations, and a proposed civil penalty in the aggregate amount of $1.1 million. An administrative hearing on the matter, previously set for the last week of March 2007, was postponed to allow the administrative record to be produced and to allow OPS an opportunity to respond to our and Equitable's motions to dismiss count one of the NOPV, which involves $0.8 million of the $1.1 million proposed penalty. This count arises out of alleged activity in 1982 and 1987, which predates our leasing and operation of the pipeline. We believe we have viable and mitigating defenses to the remaining counts and will vigorously defend all applicable assertions of violations. The administrative hearing request was withdrawn by us and Equitable in October 2009, and the parties are waiting for initial resolution on the briefs, exhibits and other documents filed or submitted by the parties in the matter.

In the ordinary course of business, we are a party to various other legal and regulatory actions. In the opinion of management, none of these actions, either individually or in the aggregate, will have a material adverse effect on our financial condition, liquidity or results of operations.

ITEM 4. Reserved

PART II

ITEM 5. Market for Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities

Our common units have been listed on the New York Stock Exchange ("NYSE"), under the symbol "MWE," since May 2, 2007. Our common units had been traded on the American Stock Exchange, under the symbol "MWE," from May 24, 2002 to May 2, 2007. Prior to May 24, 2002, our equity securities were not listed on any exchange, or traded on any public trading market.

The following table sets forth the high and low sales prices of the common units as reported by NYSE, as well as the amount of cash distributions paid per quarter for 2010 and 2009:

	Unit Price				
Quarter Ended	High	Low	Distributions Per Common Unit	Record Date	Payment Date
December 31, 2010	$43.51	$35.70	$0.65	February 7, 2011	February 14, 2011
September 30, 2010	37.00	31.50	0.64	November 8, 2010	November 12, 2010
June 30, 2010	33.45	20.96	0.64	August 2, 2010	August 13, 2010
March 31, 2010	32.00	26.05	0.64	May 3, 2010	May 14, 2010
December 31, 2009	29.94	22.20	0.64	February 5, 2010	February 12, 2010
September 30, 2009	24.00	17.87	0.64	November 2, 2009	November 13, 2009
June 30, 2009	20.00	11.20	0.64	August 3, 2009	August 14, 2009
March 31, 2009	14.30	7.30	0.64	May 4, 2009	May 15, 2009

As of February 18, 2011 there were approximately 175 holders of record of our common units.

Distributions of Available Cash

Within 45 days after the end of each quarter, we will distribute all of our "Available Cash" to unitholders of record on the applicable record date. We will make distributions of "Available Cash" to all unitholders (common and Class A), pro rata and we will make distributions of Hydrocarbon Available Cash (as defined in our amended and restated partnership agreement) pro rata to common unitholders. We define "Available Cash" in our amended and restated partnership agreement, and we generally mean, for each fiscal quarter:

- all cash and cash equivalents on hand at the end of the quarter;
- less the amount of cash that the General Partner determines in its reasonable discretion is necessary or appropriate to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments, or other agreements; or
  - provide funds for distributions to unitholders for any one or more of the next four quarters;
- plus all cash and cash equivalents on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter. Working capital borrowings are generally borrowings that are made under our Credit Facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

Generally, Hydrocarbon Available Cash is defined as all cash and cash equivalents on hand derived from or attributable to our ownership of, or sale or other disposition of, the shares of common stock of MarkWest Hydrocarbon.

Our ability to distribute available cash is contractually restricted by the terms of our credit agreement. Our credit agreement contains covenants requiring us to maintain certain financial ratios and a minimum net worth. We are prohibited from making any distribution to unitholders if such distribution would cause an event of default or otherwise violate a covenant under our credit agreement. There is no guarantee that we will pay a quarterly distribution on the common units in any quarter.

Distributions of Cash Upon Liquidation

If we dissolve in accordance with the amended and restated partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the unitholders, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2010, regarding our common units that may be issued upon conversion of outstanding phantom units granted under all of our existing equity compensation plans.

	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights(1)	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders:			
2008 Long-Term Incentive Plan(2)	1,329,160	$—	724,295
Equity compensation plans not approved by security holders:			
Long-Term Incentive Plan(3)	23,645	$—	—
Total	1,352,805		724,295

(1) Phantom units are granted with no exercise price.

(2) Includes 437,100 performance-based units that vest if we achieve established performance goals determined by the Compensation Committee of the General Partner's board of directors, and 282,000 performance-based units that vest based on our relative total unitholder return compared to a peer group.

(3) No further awards will be made pursuant to this plan.

Recent Sales of Unregistered Units

None.

Repurchase of Equity by MarkWest Energy Partners, L.P.

None.

ITEM 6. Selected Financial Data

The following table sets forth selected consolidated historical financial and operating data for MarkWest Energy Partners. For periods prior to the Merger, the information presented represents the consolidated financial position and results of operations for the Corporation. The selected financial data should be read in conjunction with the consolidated financial statements, including the notes thereto, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation in this Form 10-K.

	Year ended December 31,				
	2010	2009	2008	2007	2006
Statement of Operations:					
Revenue:					
Revenue	$1,241,563	$ 858,635	$1,060,662	$ 845,727	$ 829,298
Derivative (loss) gain(1)	(53,932)	(120,352)	277,828	(159,970)	10,383
Total revenue	1,187,631	738,283	1,338,490	685,757	839,681
Operating expenses:					
Purchased product costs	578,627	408,826	615,902	487,892	560,597
Derivative loss related to purchased product costs(1)	27,713	68,883	22,371	15,192	5,689
Facility expenses	151,449	126,977	103,682	70,863	57,403
Derivative (gain) loss related to facility expenses(1)	(1,295)	(373)	644	(14)	—
Selling, general and administrative expenses	75,258	63,728	68,975	72,484	63,360
Depreciation	123,198	95,537	67,480	41,281	31,010
Amortization of intangible assets	40,833	40,831	38,483	16,672	16,047
Loss (gain) on disposal of property, plant and equipment	3,149	1,677	178	7,743	(322)
Accretion of asset retirement obligations	237	198	129	114	102
Impairment of goodwill and long-lived assets	—	5,855	36,351	356	—
Total operating expenses	999,169	812,139	954,195	712,583	733,886
Income (loss) from operations	188,462	(73,856)	384,295	(26,826)	105,795
Other income (expense):					
Earnings from unconsolidated affiliates	1,562	3,505	90	5,309	5,316
Impairment of unconsolidated affiliate	—	—	(41,449)	—	—
Gain on sale of unconsolidated affiliate	—	6,801	—	—	—
Interest income	1,670	349	3,769	4,547	1,574
Interest expense	(103,873)	(87,419)	(64,563)	(39,435)	(40,942)
Amortization of deferred financing costs and discount (a component of interest expense)	(10,264)	(9,718)	(8,299)	(2,983)	(9,229)
Derivative gain related to interest expense(1)	1,871	2,509	—	—	—
Loss on redemption of debt	(46,326)	—	—	—	—
Miscellaneous income (expense), net(1)	1,189	2,459	(241)	233	11,984
Income (loss) before provision for income tax	34,291	(155,370)	273,602	(59,155)	74,498
Provision for income tax expense (benefit):					
Current	7,655	8,072	15,032	23,869	(179)
Deferred	(4,466)	(50,088)	53,798	(48,518)	5,431
Total provision for income tax	3,189	(42,016)	68,830	(24,649)	5,252
Net income (loss)	31,102	(113,354)	204,772	(34,506)	69,246
Net (income) loss attributable to non-controlling interest	(30,635)	(5,314)	3,301	(4,853)	(59,709)
Net income (loss) attributable to the Partnership	$ 467	$ (118,668)	$ 208,073	$ (39,359)	$ 9,537
Net (loss) income attributable to the Partnership's common unitholders per common unit(2)(3):					
Basic	$ (0.01)	$ (1.97)	$ 4.02	$ (1.72)	$ 0.42
Diluted	$ (0.01)	$ (1.97)	$ 4.02	$ (1.72)	$ 0.42
Cash distribution declared per common unit(3)	$ 2.560	$ 2.560	$ 2.059	$ 0.703	$ 0.416

	Year ended December 31,				
	2010	2009	2008	2007	2006
Balance Sheet Data (at December 31):					
Working capital	$ (43,296)	$ 13,536	$ 51,237	$ 21,932	$ 66,030
Property, plant and equipment, net	2,319,024	1,981,644	1,569,525	830,809	554,335
Total assets	3,333,362	3,014,737	2,673,054	1,524,695	1,203,241
Total long-term debt	1,273,434	1,170,072	1,172,965	552,695	526,865
Total equity	1,536,020	1,379,393	1,207,759	563,974	483,061
Cash Flow Data:					
Net cash flow provided by (used in):					
Operating activities	$ 312,328	$ 223,101	$ 226,995	$ 133,237	$ 165,969
Investing activities	(485,936)	(461,753)	(909,265)	(314,792)	(122,046)
Financing activities	143,306	333,083	647,896	170,406	(16,047)
Other Financial Data:					
Maintenance capital expenditures(4)	$ 10,286	$ 7,483	$ 7,161	$ 4,140	$ 2,460
Growth capital expenditures(4)	448,382	479,140	568,137	312,499	77,620
Total capital expenditures	$ 458,668	$ 486,623	$ 575,298	$ 316,639	$ 80,080

(1) As discussed further in Note 2 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K, volatility in any given period related to unrealized gains and losses on our derivative positions can be significant. The following table summarizes the realized and unrealized gains and losses impacting *Revenue, Purchased product costs, Facility expenses, Interest expense* and *Miscellaneous income (expense), net* (in thousands):

	Year ended December 31,				
	2010	2009	2008	2007	2006
Realized (loss) gain—revenue	$(33,560)	$ 87,289	$(15,704)	$ (15,901)	$ 17
Unrealized (loss) gain—revenue	(20,372)	(207,641)	293,532	(144,069)	10,366
Realized (loss) gain—purchased product costs	(21,909)	(53,052)	7,368	(8,829)	153
Unrealized loss—purchased product costs	(5,804)	(15,831)	(29,739)	(6,363)	(5,842)
Unrealized gain (loss)—facility expenses	1,295	373	(644)	14	—
Realized gain—interest expense	2,380	2,000	—	—	—
Unrealized (loss) gain—interest expense	(509)	509	—	—	—
Unrealized gain—miscellaneous income (expense), net	190	336	—	—	—
Total derivative (loss) gain	$(78,289)	$(186,017)	$254,813	$(175,148)	$ 4,694

(2) For the calculation of Net (loss) income attributable to the Partnership's common unitholders per common unit, see Note 24 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

(3) All per unit data where applicable has been adjusted to reflect the Exchange Ratio to give effect to the Merger (see Note 3 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K).

(4) Maintenance capital includes capital expenditures made to maintain our operating capacity and asset base. Growth capital includes expenditures made to expand the existing operating capacity, to increase the efficiency of our existing assets, and to facilitate an increase in volumes within our operations. Growth capital also includes costs associated with new well connections. Growth capital excludes expenditures for third-party acquisitions and equity investments.

Operating Data

	Year ended December 31,				
	2010	2009	2008	2007	2006
Southwest					
East Texas					
Gathering systems throughput (Mcf/d)	430,300	454,400	442,900	413,700	378,100
NGL product sales (gallons)	245,781,200	245,787,000	193,534,100	179,601,000	161,437,000
Oklahoma					
Foss Lake gathering system throughput (Mcf/d)	71,100	86,600	95,800	104,000	87,500
Stiles Ranch gathering system throughput (Mcf/d)(1)	112,300	89,300	84,800	N/A	N/A
Grimes gathering system throughput (Mcf/d)(2)	7,700	9,700	12,900	12,500	N/A
Arapaho NGL product sales (gallons)	134,118,600	126,870,500	79,416,400	87,522,000	79,093,000
Southeast Oklahoma gathering systems throughput (Mcf/d)(3)	521,400	416,800	318,700	114,000	34,000
Arkoma Connector Pipeline throughput (Mcf/d)(4)	375,900	277,300	N/A	N/A	N/A
Other Southwest					
Appleby gathering system throughput (Mcf/d)	31,600	47,300	58,400	58,700	34,200
Other gathering systems throughput (Mcf/d)(5)	7,900	10,300	11,000	8,700	18,300
Northeast					
Appalachia					
Natural gas processed (Mcf/d)(6)	188,700	194,600	202,200	200,200	203,000
Keep-whole sales (gallons)	136,711,200	145,493,100	140,847,500	126,192,600	118,581,000
Percent-of-proceeds sales (gallons)	120,255,100	99,910,200	53,987,900	43,815,100	43,271,000
Total NGL product sales (gallons)(7)	256,966,300	245,403,300	194,835,400	170,007,700	161,852,000
Michigan					
Crude oil transported for a fee (Bbl/d)	12,800	12,300	13,300	14,000	14,500
Liberty					
Marcellus Shale(8)					
Natural gas processed (Mcf/d)	215,700	51,800	18,700	N/A	N/A
Gathering system throughput (Mcf/d)	142,200	53,500	18,700	N/A	N/A
NGL product sales (gallons)	119,921,400	34,409,000	N/A	N/A	N/A
Gulf Coast					
Refinery off-gas processed (Mcf/d)	118,600	120,200	122,900	114,500	124,300
Liquids fractionated (Bbl/d)	22,500	23,200	24,400	25,000	26,200

(1) The 2008 volume reported for the Stiles Ranch gathering system is the average daily rate for the period of operation, which began November 2008.

(2) We acquired the Grimes gathering system on December 29, 2006.

(3) We began gathering gas on that the Woodford gathering system in December 2006. The volume reported for 2006 is the average daily rate for the month of December.

(4) The Arkoma Connector Pipeline was placed into service in July 2009. The volume reported is the average daily rate for the days of operation.

(5) Excludes lateral pipelines where revenue is not based on throughput.

(6) Includes throughput from the Kenova, Cobb, and Boldman processing plants.

(7) Represents sales at the Siloam fractionator. The total sales in 2010 and 2009 exclude 60.9 million and 23.3 million gallons sold by the Northeast on behalf of Liberty, respectively; those volumes are included in the NGL product sales for Liberty.

(8) The volumes reported represent the average daily rate for the period of operation.

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis ("MD&A") contains statements that are forward-looking and should be read in conjunction with *Selected Financial Data* and our consolidated financial statements and accompanying notes included elsewhere in this report. Statements that are not historical facts are forward-looking statements. We use words such as "could," "may," "predict," "should," "expect," "hope," "continue," "potential," "plan," "intend," "anticipate," "project," "believe," "estimate," and similar expressions to identify forward-looking statements. These statements are based on current expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. Forward-looking statements are not guarantees and actual results could differ materially from those expressed or implied in the forward-looking statements as a result of a number of factors. We do not update publicly any forward-looking statement with new information or future events. Undue reliance should not be placed on forward-looking statements as many of these factors are beyond our ability to control or predict.

Overview

We are a master limited partnership engaged in the gathering, transportation and processing of natural gas; the transportation, fractionation, marketing and storage of NGLs; and the gathering and transportation of crude oil. We have extensive natural gas gathering, processing and transmission operations in the southwest, Gulf Coast and northeast regions of the United States, including the Marcellus Shale, and are the largest natural gas processor and fractionator in the Appalachian region.

Significant Financial and Other Highlights

Significant financial and other highlights for the year ended December 31, 2010 are listed below. Refer to *Results of Operations* and *Liquidity and Capital Resources* for further details.

- Total segment operating income before items not allocated to segments increased approximately $157.5 million, or 50%, for the year ended December 31, 2010 compared to the same period in 2009. The increase is primarily due to higher commodity prices in 2010, expanding operations in the Liberty segment, increased volumes from a large producer in the Woodford system and increased volumes from the Granite Wash formation. The increase in segment income was partially offset by an $89.7 million decrease in net cash flow from the settlement of commodity derivative positions.
- In April 2010, we received net proceeds of approximately $142.3 million from a public offering of approximately 4.9 million newly issued common units, which includes the full exercise of the underwriters' over-allotment option.
- In July 2010, we entered into an amended and restated credit agreement that provides for our Credit Facility with a capacity of up to $705 million, with an uncommitted accordion feature of up to $195 million. Additionally, as a result of adding a new member to the bank group, all of our financial derivative positions are currently with participating bank group members and we are not subject to any margin requirements.
- In November 2010, we completed a public offering of $500.0 million in aggregate principal amount of 6.75% senior unsecured notes due November 2020. We received net proceeds of approximately $490.3 million.
- In the fourth quarter of 2010, we redeemed $225 million aggregate principal amount of our 6.875% senior notes due 2014 and $150 million aggregate principal amount of our 6.875% senior notes due 2014. We recorded a loss on redemption of debt of approximately $46.3 million (see Note 17 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further details).
- We received $158.3 million of cash contributions to MarkWest Liberty Midstream from M&R.

Impact of Acquisitions on Comparability of Financial Results

In reviewing our historical results of operations, investors should consider the impact of our past acquisitions, which fundamentally affect the comparability of our results of operations over the periods discussed.

Two acquisitions occurred in 2008 and are included in the results of operations from the acquisition date.

- In 2008 we acquired a 40% interest in Centrahoma Processing LLC, which is accounted for under the equity method, for $23.6 million including a capital call. As a result, our share of Centrahoma's net loss from March 2008 to December 2008 is included in *Earnings from unconsolidated affiliates* in the accompanying Consolidated Statements of Operations for the year ended December 31, 2008.
- The PQ Gathering Assets, L.L.C. ("PQ Assets") acquisition closed on July 31, 2008 for consideration of $41.3 million. As a result, five months of activity for PQ Assets is reflected in the accompanying Consolidated Statements of Operations for the year ended December 31, 2008.

Results of Operations

Segment Reporting

We classify our business in four reportable segments: Southwest, Northeast, Liberty and Gulf Coast. We capture information in MD&A by geographical segment. Items below *Income (loss) from operations* in the accompanying Consolidated Statements of Operations, certain compensation expense, certain other non-cash items and any unrealized gains (losses) from derivative instruments are not allocated to individual business segments. Management does not consider these items allocable to or controllable by any individual business segment and therefore excludes these items when evaluating segment performance. The 2010 and 2009 segment results are also adjusted to exclude the portion of operating income attributable to the non-controlling interests; non-controlling interests were immaterial prior to 2009. As a result of the new Liberty segment, segment information for the year ended December 31, 2008 has been recast.

Year Ended December 31, 2010, Compared to Year Ended December 31, 2009

The tables below present financial information, as evaluated by management, for the reported segments for the years ended December 31, 2010 and 2009. The information includes net operating margin, a non-GAAP financial measure. For a reconciliation of net operating margin to *Income (loss) from operations*, the most comparable GAAP financial measure, see *Our Contracts* discussion in Item 1. Business.

Southwest

	Year ended December 31,			
	2010	2009	$ Change	% Change
	(in thousands)			
Revenue	$665,768	$492,369	$173,399	35%
Purchased product costs	308,960	221,021	87,939	40%
Net operating margin	356,808	271,348	85,460	31%
Facility expenses	81,772	73,621	8,151	11%
Portion of operating income attributable to non-controlling interests	6,440	2,613	3,827	146%
Operating income before items not allocated to segments	$268,596	$195,114	$ 73,482	38%

Revenue. Revenue increased primarily due to higher NGL prices. Revenue from NGL and condensate sales increased approximately $149.3 million across the segment, partially offset by a $2.5 million decrease in revenue from natural gas sales. An increase in volumes from a large producer in our Woodford Shale operations also contributed to the increase in product sales. Gathering, treating, and compression fee revenue also increased $23.6 million due to a full year of the Arkoma Connector Pipeline operations that began in mid-July 2009 and higher volumes in the Woodford Shale and Stiles Ranch. The increase in revenue was partially offset by a decrease in gathered volumes in the Foss Lake, East Texas and Other Southwest areas and a change from a gas purchase contract to a gas gathering contract with a significant producer in the Other Southwest areas. The decline in gathered volumes in these conventional natural gas formations may continue until natural gas prices improve.

Purchased Product Costs. Purchased product costs increased primarily due to higher commodity prices and increased volumes in certain areas, which was partially offset by a decrease in plant inlet volumes in the Foss Lake, East Texas and Other Southwest areas and a change from a gas purchase contract to a gas gathering contract with a significant producer in the Other Southwest areas.

Facility Expenses. Facility expenses increased primarily due to higher operating expenses in Southeast Oklahoma resulting from the start of the Arkoma Connector Pipeline in mid-July 2009 and the increased volumes primarily in the Woodford Shale and Stiles Ranch gathering systems. The increase was partially offset by a reduction in repairs and maintenance expense related to environmental costs in 2009 in East Texas that did not recur in 2010.

Portion of Operating Income Attributable to Non-controlling Interests. Portion of operating income attributable to non-controlling interests represents our partners' share in net operating income of MarkWest Pioneer and Wirth Gathering Partnership. The increase resulted from the Arkoma Connector Pipeline being placed in service in mid-July 2009.

Northeast

	Year ended December 31, 2010	2009	$ Change	% Change
	(in thousands)			
Revenue	$384,724	$260,529	$124,195	48%
Purchased product costs	252,827	175,326	77,501	44%
Net operating margin	131,897	85,203	46,694	55%
Facility expenses	19,513	20,339	(826)	(4)%
Operating income before items not allocated to segments	$112,384	$ 64,864	$ 47,520	73%

Revenue. Revenue increased primarily due to higher commodity prices realized on NGL sales, as well as an increase in volumes from a significant customer under a percent-of-proceeds arrangement. The revenue increases were partially offset by a decrease in volumes processed under keep-whole terms primarily due to the required repairs of a significant transmission pipeline feeding our Kenova plant. The transmission pipeline is scheduled to be repaired in mid 2011 after which we expect volumes to return to normal levels.

Purchased Product Costs. Purchased product costs increased due to higher prices for the natural gas that is purchased to satisfy the keep-whole arrangements, as well as the overall increase in volumes.

Liberty

	Year ended December 31, 2010	2009	$ Change	% Change
	(in thousands)			
Revenue	$105,911	$47,968	$57,943	121%
Purchased product costs	16,840	12,479	4,361	35%
Net operating margin	89,071	35,489	53,582	151%
Facility expenses	24,028	16,268	7,760	48%
Portion of operating income attributable to non-controlling interests	26,126	6,637	19,489	294%
Operating income before items not allocated to segments	$ 38,917	$12,584	$26,333	209%

Revenue. Revenue increased due to ongoing expansion of the Liberty operations and higher NGL prices. Revenue increased approximately $35.8 million related to gathering fees and gathering system lease income and approximately $24.6 million related to NGL product sales.

Purchased Product Costs. Purchased product costs increased primarily due to the purchase of product from certain producers. During 2010, the Liberty segment purchased stored NGLs from producers monthly, whereas prior to this arrangement the Liberty segment did not purchase any NGLs and acted solely as the producers' agent providing processing, storage and marketing services. The increase was partially offset by the purchased product costs incurred in 2009 related to an interim plant that ceased operations in January 2010.

Facility Expenses. Facility expenses increased primarily due to the ongoing expansion of the Liberty operations, which includes the start-up of the Majorsville processing plant in the third quarter of 2010. The increase in facility expenses was partially offset by a decrease in compressor rental expense as we have purchased certain compressors that had been leased.

Portion of Operating Income Attributable to Non-controlling Interests. Portion of operating income attributable to non-controlling interests represents M&R's 40% interest in net operating income of MarkWest Liberty Midstream. The increase is the result of the formation of the joint venture on February 27, 2009 and the ongoing expansion of the Liberty operations.

Gulf Coast

	Year ended December 31, 2010	Year ended December 31, 2009	$ Change	% Change
	(in thousands)			
Revenue	$85,160	$57,769	$27,391	47%
Purchased product costs	—	—	—	N/A
Net operating margin	85,160	57,769	27,391	47%
Facility expenses	33,337	16,094	17,243	107%
Operating income before items not allocated to segments	$51,823	$41,675	$10,148	24%

Revenue. Revenue increased primarily due to $15.3 million related to the SMR and higher commodity prices. See Note 5 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion of the SMR.

Facility Expenses. Facility expenses increased primarily due to $14.7 million of SMR operating expenses and increased utilities and chemicals expense.

Reconciliation of Segment Operating Income to Consolidated Income (Loss) Before Provision for Income Tax

The following table provides a reconciliation of segment revenue to total revenue and operating income before items not allocated to segments to our consolidated income (loss) before provision for income tax for the years ended December 31, 2010 and 2009. The ensuing items listed below the *Total segment revenue* and *Operating income* lines are not allocated to business segments as management does not consider these items allocable to any individual segment.

	Year ended December 31, 2010	2009	$ Change	% Change
	(in thousands)			
Total segment revenue	$1,241,563	$ 858,635	$382,928	45%
Derivative loss not allocated to segments	(53,932)	(120,352)	66,420	(55)%
Total revenue	$1,187,631	$ 738,283	$449,348	61%
Operating income before items not allocated to segments	$ 471,720	$ 314,237	$157,483	50%
Portion of operating income attributable to non-controlling interests	32,566	9,250	23,316	252%
Derivative loss not allocated to segments	(80,350)	(188,862)	108,512	(57)%
Compensation expense included in facility expenses not allocated to segments	(1,890)	(1,032)	(858)	83%
Facility expenses adjustments	9,091	377	8,714	2,311%
Selling, general and administrative expenses	(75,258)	(63,728)	(11,530)	18%
Depreciation	(123,198)	(95,537)	(27,661)	29%
Amortization of intangible assets	(40,833)	(40,831)	(2)	0%
Loss on disposal of property, plant and equipment	(3,149)	(1,677)	(1,472)	88%
Accretion of asset retirement obligations	(237)	(198)	(39)	20%
Impairment of long-lived assets	—	(5,855)	5,855	(100)%
Income (loss) from operations	188,462	(73,856)	262,318	(355)%
Earnings from unconsolidated affiliates	1,562	3,505	(1,943)	(55)%
Gain on sale of unconsolidated affiliate	—	6,801	(6,801)	(100)%
Interest income	1,670	349	1,321	379%
Interest expense	(103,873)	(87,419)	(16,454)	19%
Amortization of deferred financing costs and discount (a component of interest expense)	(10,264)	(9,718)	(546)	6%
Derivative gain related to interest expense	1,871	2,509	(638)	(25)%
Loss on redemption of debt	(46,326)	—	(46,326)	N/A
Miscellaneous income, net	1,189	2,459	(1,270)	(52)%
Income (loss) before provision for income tax	$ 34,291	$(155,370)	$189,661	(122)%

Derivative Loss Not Allocated to Segments. Unrealized loss from the mark-to-market of our derivative instruments was $24.9 million in 2010 compared to $223.1 million in 2009. Realized loss from the settlement of our derivative instruments was $55.5 million in 2010 compared to realized gain of $34.2 million in 2009. The total change of $108.5 million is due mainly to volatility in commodity prices when comparing prices in 2010 with 2009. Realized gains in 2009 also include net gains of $15.2 million due to the early settlement of certain positions as discussed in Note 6 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

Facility Expenses Adjustments. Facility expenses adjustments consist of the reallocation of the MarkWest Pioneer field services fee and the reallocation of the interest expense related to the SMR which is included in facility expenses for the purposes of evaluating the performance of the Gulf Coast segment.

Selling, General and Administrative Expenses. Selling, general and administrative expenses increased primarily due to higher share-based compensation expense related to the January 2010 unrestricted unit grant, as well as increases in headcount, short-term incentive compensation, insurance and corporate office rent. These increases were partially offset by a decrease in professional services expense.

Depreciation. Depreciation increased due to depreciation on additional projects completed during 2010 and 2009.

Impairment of Long-Lived Assets. During the year ended December 31, 2009, we recognized an impairment of $5.9 million related to certain gas-gathering and intangible assets in the Southwest segment.

Gain on Sale of Unconsolidated Affiliate. During the year ended December 31, 2009, we sold our equity investment in Starfish. See Note 5 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion.

Interest Expense. Interest expense increased primarily due to additional borrowings in May 2009 and the net increase in our borrowings resulting from the 2020 Senior Notes offering and related redemption of the 2014 Senior Notes. Interest expense of $7.1 million related to the SMR also contributed to the increase.

Loss on Redemption of Debt. Loss on redemption of debt relates to the redemption of $375 million of our 2014 Senior Notes in the fourth quarter of 2010. Approximately $36.6 million relates to the non-cash write off of the unamortized discount and deferred finance costs associated with these senior notes and approximately $9.7 million relates to the payment of the related call and tender premiums. See Note 17 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further details.

Derivative Gain Related to Interest Expense. Derivative gain related to interest expense relates to changes in the fair value of interest rate swaps which we used to manage the interest rate risk associated with the fair value of our fixed rate borrowings. The interest rate swaps effectively converted a portion of the underlying cash flows related to our long-term fixed rate debt securities into variable rate cash flows in order to achieve a desired mix of fixed and variable rate debt. We settled all of the outstanding interest rate swaps in January 2010. See Note 6 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further details.

Year Ended December 31, 2009, Compared to Year Ended December 31, 2008

The tables below present financial information, as evaluated by management, for the reported segments for the years ended December 31, 2009 and 2008. The information includes net operating margin, a non-GAAP financial measure. For a reconciliation of net operating margin to *Income (loss) from operations*, the most comparable GAAP financial measure, see *Our Contracts* discussion in Item 1. Business.

Southwest

	Year ended December 31,			
	2009	2008	$ Change	% Change
	(in thousands)			
Revenue	$492,369	$652,365	$(159,996)	(25)%
Purchased product costs	221,021	387,516	(166,495)	(43)%
Net operating margin	271,348	264,849	6,499	2%
Facility expenses	73,621	62,369	11,252	18%
Portion of operating income attributable to non-controlling interests	2,613	—	2,613	N/A
Operating income before items not allocated to segments	$195,114	$202,480	$ (7,366)	(4)%

Revenue. Revenue decreased primarily due to lower commodity prices. Revenue from NGL, natural gas and condensate sales decreased across the segment by $191.2 million. The change from a gas purchase contract to a gas gathering contract with a significant producer in the Other Southwest area also contributed to the decline in revenue. The revenue decreases were partially offset by increased volumes processed at the Arapaho facilities associated with the Stiles Ranch gathering system that began operations in the fourth quarter of 2008 and by an increase of $33.0 million in gathering, treating, and transportation fee revenue due primarily to the continued expansion of our operations in the Woodford Shale, including the start of the Arkoma Connector Pipeline operations.

Purchased Product Costs. NGL and natural gas purchases decreased due primarily to lower commodity prices as well as the contract change for a significant producer in the Other Southwest area.

Facility Expenses. Facility expenses increased due primarily to the continued expansion of operations for the Woodford gathering system, including the PQ Assets acquisition in July of 2008, the expansion of the Foss Lake gathering and processing operations, and increased repairs and maintenance resulting from the completed non-recurring environmental remediation costs in East Texas.

Portion of Operating Income Attributable to Non-controlling Interests. Portion of operating income attributable to non-controlling interest represents our partners' interest in the net operating income of MarkWest Pioneer and Wirth Gathering Partnership.

Northeast

	Year ended December 31, 2009	2008	$ Change	% Change
	(in thousands)			
Revenue	$260,529	$313,921	$(53,392)	(17)%
Purchased product costs	175,326	228,386	(53,060)	(23)%
Net operating margin	85,203	85,535	(332)	(0)%
Facility expenses	20,339	20,869	(530)	(3)%
Operating income before items not allocated to segments	$ 64,864	$ 64,666	$ 198	0%

Revenue. Revenue decreased due mainly to lower commodity prices realized on NGL sales from the Appalachia region. This decrease was partially offset by changes in contract terms and increased volumes from a large producer in the Appalachia region. Revenue also decreased $4.2 million in our Western Michigan area due to the shut-in and subsequent sale or abandonment of the assets in this area.

Purchased Product Costs. Purchased product costs decreased due to lower prices for the natural gas that must be purchased to satisfy the keep-whole arrangements in the Appalachia area. The effect of the lower prices was partially offset by increased volumes and changes in market value. Purchased product costs in 2008 included an expense of $6.7 million to write down inventories to market value at December 31, 2008. Purchased product costs also decreased $2.8 million in our Western Michigan area due to the shut-in and subsequent sale or abandonment of the assets in this area.

Liberty

	Year ended December 31, 2009	2008	$ Change	% Change
	(in thousands)			
Revenue	$47,968	$2,334	$45,634	1,955%
Purchased product costs	12,479	—	12,479	N/A
Net operating margin	35,489	2,334	33,155	1,421%
Facility expenses	16,268	2,006	14,262	711%
Portion of operating income attributable to non-controlling interests	6,637	—	6,637	N/A
Operating income before items not allocated to segments	$12,584	$ 328	$12,256	3,737%

The results of operations for the year ended December 31, 2009 include our operations in the northern West Virginia and western Pennsylvania areas. Revenue for the year ended December 31, 2009 consists of approximately $30.1 million of fee-based revenue. Approximately $17.9 million of the revenue relates to NGL product sales under percent-of-proceeds arrangements. The portion of operating income attributable to non-controlling interest represents M&R's interest in the net operating income of MarkWest Liberty Midstream.

We began construction in the second quarter of 2008 and commenced gas gathering and processing operations in the fourth quarter of 2008.

Gulf Coast

	Year ended December 31, 2009	2008	$ Change	% Change
	(in thousands)			
Revenue	$57,769	$92,042	$(34,273)	(37)%
Purchased product costs	—	—	—	N/A
Net operating margin	57,769	92,042	(34,273)	(37)%
Facility expenses	16,094	17,368	(1,274)	(7)%
Operating income before items not allocated to segments	$41,675	$74,674	$(32,999)	(44)%

Revenue. Revenue decreased due to lower commodity prices and decreased inlet volumes. The decrease in revenue was partially offset by a higher percent-of-proceeds received from one of our refinery customers under a variable percent-of-proceeds contract.

Facility Expenses. Facility expenses decreased primarily due to lower electricity rates. The decrease was partially offset by the cost of the plant turnaround completed in March 2009.

Reconciliation of Segment Operating Income to Consolidated (Loss) Income Before Provision for Income Tax

The following table provides a reconciliation of segment revenue to total revenue and operating income before items not allocated to segments to our consolidated (loss) income before provision for income tax for the years ended December 31, 2009 and 2008. The ensuing items listed below the *Total segment revenue* and *Operating income* lines are not allocated to business segments as management does not consider these items allocable to any individual segment.

	Year ended December 31, 2009	Year ended December 31, 2008	$ Change	% Change
	(in thousands)			
Total segment revenue	$ 858,635	$1,060,662	$(202,027)	(19)%
Derivative (loss) gain not allocated to segments	(120,352)	277,828	(398,180)	(143)%
Total revenue	$ 738,283	$1,338,490	$(600,207)	(45)%
Operating income before items not allocated to segments	$ 314,237	$ 342,148	$ (27,911)	(8)%
Portion of operating income attributable to non-controlling interests	9,250	—	9,250	N/A
Derivative (loss) gain not allocated to segments	(188,862)	254,813	(443,675)	(174)%
Compensation expense included in facility expenses not allocated to segments	(1,032)	(1,070)	38	(4)%
Facility expenses adjustments	377	—	377	N/A
Selling, general and administrative expenses	(63,728)	(68,975)	5,247	(8)%
Depreciation	(95,537)	(67,480)	(28,057)	42%
Amortization of intangible assets	(40,831)	(38,483)	(2,348)	6%
Loss on disposal of property, plant and equipment	(1,677)	(178)	(1,499)	842%
Accretion of asset retirement obligations	(198)	(129)	(69)	53%
Impairment of goodwill and long-lived assets	(5,855)	(36,351)	30,496	(84)%
(Loss) income from operations	(73,856)	384,295	(458,151)	(119)%
Earnings from unconsolidated affiliates	3,505	90	3,415	3,794%
Impairment of unconsolidated affiliate	—	(41,449)	41,449	(100)%
Gain on sale of unconsolidated affiliate	6,801	—	6,801	N/A
Interest income	349	3,769	(3,420)	(91)%
Interest expense	(87,419)	(64,563)	(22,856)	35%
Amortization of deferred financing costs and discount (a component of interest expense)	(9,718)	(8,299)	(1,419)	17%
Derivative gain related to interest expense	2,509	—	2,509	N/A
Miscellaneous income (expense), net	2,459	(241)	2,700	(1,120)%
(Loss) income before provision for income tax	$(155,370)	$ 273,602	$(428,972)	(157)%

Derivative (Gain) Loss Not Allocated to Segments. Unrealized loss from the mark-to-market of our derivative instruments was $223.1 million in 2009 compared to unrealized gain of $263.1 million in 2008. Realized gain from the settlement of our derivative instruments was $34.2 million in 2009 compared to realized loss of $8.3 million in 2008. The total change of $443.7 million is due mainly to volatility in commodity prices when comparing prices in 2009 with 2008. Realized gains in 2009 also include net gains of $15.2 million due to the early settlement of certain positions as discussed in Note 6 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

Selling, General and Administrative Expenses. Selling, general and administrative expenses decreased primarily due to lower expense related to share-based incentive compensation plans as the established targets for certain awards are not currently expected to be fully achieved. Additionally, we incurred $2.6 million of expenses related to the Merger during 2008 which did not recur in 2009. These costs are partially offset by increases in headcount and short-term incentive compensation.

Depreciation and Amortization of Intangible Assets. Depreciation and amortization expense increased partially due to a $4.4 million increase caused by the step-up in value of property, plant, and equipment and intangible assets as a result of the Merger. The remaining increase is due to depreciation on additional projects completed during 2008 and 2009.

Impairment of Goodwill and Long-Lived Assets. During the year ended December 31, 2009, we recognized an impairment of $5.9 million related to certain gas-gathering and intangible assets in the Southwest segment.

During the year ended December 31, 2008, we recognized an impairment charge of $7.6 million related to certain gas-gathering assets in the Northeast segment. See Note 13 of the accompanying Notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion.

During the year ended December 31, 2008, we recognized an impairment charge of $28.7 million related to goodwill that was recorded as a result of the purchase accounting for the Merger. The impairment was due primarily to a reduction in our forecasted cash flows caused by a significant decline in commodity prices in the fourth quarter of 2008. See Note 13 of the accompanying Notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion.

Earnings from Unconsolidated Affiliates. Earnings from unconsolidated affiliates is related to our investment in Starfish and Centrahoma. The increase in our earnings from unconsolidated affiliates is due mainly to increased volumes and prices at Starfish. Additionally, operations at Starfish were disrupted in the third and fourth quarter of 2008 due to damage caused by Hurricane Ike. We sold our interest in Starfish effective December 31, 2009. See Note 5 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

Impairment of Unconsolidated Affiliate. During the year ended December 31, 2008, we recognized an impairment charge of $41.4 million related to an other-than-temporary decline in the fair value of our equity investment in Starfish. See Note 14 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion.

Gain on Sale of Unconsolidated Affiliate. During the year ended December 31, 2009, we sold our equity investment in Starfish. See Note 5 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion.

Interest Income. Interest income decreased due to a significant reduction in the excess cash available for short-term investments as a result of our capital spending requirements during 2009. Interest rates were also lower on the amounts that were invested in 2009.

Interest Expense. Interest expense increased primarily due to additional borrowings in 2008 and 2009 to fund the Merger and our capital plan. The increase in interest expense was partially offset by a $2.7 million increase in capitalized interest.

Amortization of Deferred Financing Costs and Discount. Amortization of deferred financing costs and discount increased due mainly to the amortization of deferred financing costs associated with the issuance of senior notes in May 2009.

Derivative Gain Related to Interest Expense. Derivative gain related to interest expense relates to changes in the fair value of interest rate swaps which we use to manage the interest rate risk associated with the fair value of our fixed rate borrowings. The interest rate swaps effectively convert a portion of the underlying cash flows related to our long-term fixed rate debt securities into variable rate cash flows in order to achieve a desired mix of fixed and variable rate debt. We settled all of the outstanding interest rate swaps in January 2010. See Note 6 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further details.

Liquidity and Capital Resources

Our primary strategy is to expand our asset base through organic growth projects and selective third-party acquisitions that are accretive to our cash available for distribution per common unit. In 2010, we spent approximately $458.7 million on organic expansion opportunities, of which a portion was funded by our MarkWest Liberty Midstream joint venture partner as discussed below.

Our share of growth capital expenditures for 2011 is expected to be approximately $370 million to $420 million and the remainder will be funded through cash contributions from our MarkWest Liberty Midstream joint venture partner and cash generated from the operations of the joint venture. This growth capital forecast excludes approximately $230 million paid for the Langley Acquisition. Growth capital includes expenditures made to expand the existing operating capacity, to increase the efficiency of our existing assets, and to facilitate an increase in volumes within our operations. Growth capital also includes costs associated with new well connections. Growth capital excludes expenditures for third-party acquisitions and equity investments. Maintenance capital expenditures in 2011 are expected to be approximately $10 - $20 million. Maintenance capital includes capital expenditures made to maintain our operating capacity and asset base.

Our primary sources of liquidity to meet operating expenses, pay distributions to our unitholders and fund capital expenditures are cash flows generated by our operations, our Credit Facility and access to debt and equity markets, both public and private. We will also consider the use of alternative financing strategies such as entering into additional joint venture arrangements and the sale of non-strategic assets.

During 2010, we completed the following transactions that have improved our liquidity position, which are discussed in further detail below:

- Increased the borrowing capacity under our Credit Facility from $435.6 million to $705 million.
- Received net proceeds of approximately $490.3 million from a public offering of senior notes and redeemed $375 million aggregate principal amount of our 6.875% 2014 Senior Notes.
- Received net proceeds of approximately $142.3 million from a public offering of common units.
- Received $158.3 million of cash contributions to MarkWest Liberty Midstream from M&R.

As a result of these financing activities, management believes that expenditures for our current capital projects will be funded with cash flows from operations, current cash balances, contributions by our joint venture partner for capital projects encompassed by the joint venture, and our current borrowing capacity under the Credit Facility. However, it may be necessary to raise additional funds to finance our future capital requirements. Our access to capital markets can be impacted by factors outside our control, including economic conditions; however, we believe that our strong cash flows and balance sheet, our Credit Facility and our credit rating will provide us with adequate access to funding given our expected cash needs. Any new borrowing cost would be affected by market conditions and long-term debt ratings assigned by independent rating agencies. As of February 18, 2011, our credit ratings were Ba3 with a Stable outlook by Moody's Investors Service and BB− with a Stable outlook by Standard & Poor's, which reflects upgrades by both agencies in 2010. Fitch Ratings initiated coverage in June 2010 and assigned us a current credit rating of BB with a Stable outlook. Changes in our operating results, cash flows or financial position could impact the ratings assigned by the various rating agencies. Should our credit ratings be adjusted downward, we may incur higher costs to borrow, which could have a material impact on our financial condition and results of operations.

Debt Financing Activities

In July 2010, our credit agreement was amended and restated to increase the borrowing capacity of our Credit Facility to $705 million, with an uncommitted accordion feature of up to $195 million (see Note 17 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further details). The Credit Facility matures on July 1, 2015.

Under the provisions of the Credit Facility, we are subject to a number of restrictions and covenants. Significant financial covenants under the Credit Facility include the Interest Coverage Ratio (as defined in the Credit Facility), which must be greater than 2.75 to 1.0, and the Total Leverage Ratio (as defined in the Credit Facility), which must be less than 5.25 to 1.0. As of December 31, 2010, we were in compliance with all of our debt covenants, and we expect to remain in compliance with all of our debt covenants for at least the next twelve months.

These covenants are used to calculate the available borrowing capacity on a quarterly basis. As of February 18, 2011, we had $70.4 million of borrowings outstanding and $27.4 million of letters of credit outstanding under the Credit Facility, leaving approximately $607.2 million available for borrowing.

The Credit Facility limits our ability to enter into transactions with parties that require margin calls under certain derivative instruments. The Credit Facility prevents members of the participating bank group from requiring margin calls. As of February 18, 2011, all of our derivative positions are with members of the participating bank group and are not subject to margin deposit requirements. We believe this arrangement gives us additional liquidity as it allows us to enter into derivative instruments without utilizing cash for margin calls or requiring the use of letters of credit.

On November 2, 2010, we completed a public offering of $500.0 million in aggregate principal amount of 6.75% senior unsecured notes due 2020. The proceeds were used to redeem the 2014 Senior Notes, to repay all borrowings outstanding under the Credit Facility and to provide working capital for general partnership purposes.

As of December 31, 2010, we had three series of Senior Notes outstanding: $275.0 million aggregate principal issued in July 2006 and due July 2016; $500.0 million aggregate principal issued in April and May 2008 and due April 2018; and $500.0 million aggregate principal issued in November 2010 and due November 2020. For further discussion of the Senior Notes, see Note 17 and Note 30 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

The indentures governing the Senior Notes limit the activity of the Partnership and its restricted subsidiaries. The indentures place limits on the ability of the Partnership and its restricted subsidiaries to incur additional indebtedness; declare or pay dividends or distributions or redeem, repurchase or retire equity interests or subordinated indebtedness; make investments; incur liens; create any consensual limitation on the ability of the Partnership's restricted subsidiaries to pay dividends or distributions, make loans or transfer property to the Partnership; engage in transactions with the Partnership's affiliates; sell assets, including equity interests of the Partnership's subsidiaries; make any payment on or with respect to, or purchase, redeem, defease or otherwise acquire or retire for value any subordinated obligation or guarantor subordination obligation (except principal and interest at maturity); and consolidate, merge or transfer assets.

Equity Offerings

On April 6, 2010, we completed a public offering of approximately 4.9 million newly issued common units representing limited partner interests, which includes the full exercise of the underwriters' over-allotment option, at a price of $30.43 per common unit. Net proceeds of approximately $142.3 million were used to repay borrowings under our Credit Facility and to partially fund our ongoing capital expenditure program.

On January 14, 2011, we completed a public offering of approximately 3.45 million newly issued common units representing limited partner interests, which includes the full exercise of the underwriters' over-allotment option, at a price of $41.20 per common unit. Net proceeds of approximately $138 million were used to partially fund our ongoing capital expenditure program, including a portion of the costs associated with the Langley Acquisition.

Liquidity Risks and Uncertainties

Our ability to pay distributions to our unitholders and to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance. That, in turn, will be affected by prevailing economic conditions in our industry, as well as financial, business and other factors, some of which are beyond our control. The global economic recession had a significant adverse impact on commodity prices during 2009. Although NGL prices have increased in 2010 compared to 2009, our operating performance could be negatively impacted if the increases in NGL prices are not sustained. Natural gas prices have remained at relatively low levels throughout 2009 and 2010. Although low natural gas prices increase our earnings under keep-whole contracts in the short term, our earnings could be adversely impacted if the low natural gas prices do not increase and result in reduced volumes from our producers over the long term. Additionally, new legislation recently enacted by Congress could limit our ability to execute our hedging strategy, which would increase our exposure to adverse changes in commodity prices.

The prevailing uncertainty that exists in the financial markets has created an increased risk of counterparty default that could impact our liquidity in several ways. During 2011, we expect that we will be required to borrow additional amounts under our Credit Facility. However, our ability to access these funds could be adversely impacted by the failure of one or more of the members of the participating bank group. Although management believes that the participating members are financially sound, an increased risk does exist. Also, because the participating members of our bank group are the counterparties to all of our derivative instruments, the failure of one of more members could significantly reduce the cash flow from operations related to the settlement of these positions. The cash flows generated by our operations could also be significantly reduced if any of our major customers defaulted on its obligations to us. The creditworthiness of our trade customers is continuously monitored, and we believe that our current group of customers are sound and represent no abnormal credit risk. Additionally, our supply of gas is dependent on a few large producers in each of our operating segments. If any of these producers were forced to significantly curtail or cease production due to economic adversity, our cash flows from operations could be significantly reduced.

Cash Flow

The following table summarizes cash inflows (outflows) (in thousands).

	Year ended December 31,		
	2010	2009	Change
Net cash provided by operating activities	$ 312,328	$ 223,101	$ 89,227
Net cash used in investing activities	(485,936)	(461,753)	(24,183)
Net cash provided by financing activities	143,306	333,083	(189,777)

Net cash provided by operating activities increased primarily due to a $157.5 million increase in operating income, excluding derivative gains and losses, in our operating segments and an increase in operating cash flows resulting from changes in working capital, which was partially offset by an $89.7 million decrease in net cash flow from the settlement of commodity derivative positions.

Net cash used in investing activities increased primarily due to a change in restricted cash of $28.0 million and net proceeds of $25.0 million related to the sale of our equity interest in Starfish in 2009. These increases were partially offset by a $28.0 million decrease in capital expenditures.

Net cash provided by financing activities decreased primarily due to:

- In 2009, we received $60.7 million in net proceeds from the sale of equity interest in the Arkoma joint venture and $73.1 million in proceeds from the SMR Transaction.
- $36.3 million decrease in proceeds from public offerings,
- $36.2 million decrease in contributions received from our joint venture partner,
- $25.8 million increase in distributions to common unitholders,
- $12.4 million increase in payments for debt issuance costs, deferred financing costs and registration costs, and
- $9.7 million of premiums paid for the redemption of our 2014 Senior Notes.
- These changes were offset by a $74.1 million increase in net borrowings. See *Debt Financing Activities* and *Equity Offerings* above for a discussion of our 2010 financing activities.

Total Contractual Cash Obligations

A summary of our total contractual cash obligations as of December 31, 2010, is as follows (in thousands):

	Payment Due by Period				
Type of obligation	**Total Obligation**	**Due in 2011**	**Due in 2012 - 2013**	**Due in 2014 - 2015**	**Thereafter**
Long-term debt	$1,275,000	$ —	$ —	$ —	$1,275,000
Interest payments on long-term debt(1)	805,875	100,875	201,750	201,750	301,500
Operating leases and long-term storage agreement(2)	54,213	7,893	15,427	14,739	16,154
Purchase obligations(3)	55,995	55,995	—	—	—
Natural gas purchase obligations(4)	112,899	27,313	54,842	30,744	—
SMR Liability(5)	334,501	17,412	34,824	34,824	247,441
Other long-term liabilities reflected on the Consolidated Balance Sheets:					
Asset retirement obligation(6)	4,029	—	—	—	4,029
Total contractual cash obligations	$2,642,512	$209,488	$306,843	$282,057	$1,844,124

(1) Assumes that we incur interest expense at 8.5% on the 2016 Senior Notes, 8.75% on the 2018 Senior Notes and 6.75% on the 2020 Senior Notes.

(2) Amounts relate primarily to a long-term propane storage agreement and our office and vehicle leases.

(3) Represents purchase orders and contracts related to purchase of property, plant and equipment. Purchase obligations exclude current and long-term unrealized losses on derivative instruments included on the accompanying Consolidated Balance Sheets, which represent the current fair value of various derivative contracts and do not represent future cash purchase obligations. These contracts are generally 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.

(4) Natural gas purchase obligations consist primarily of a purchase agreement with a producer in the Appalachia region. The contract provides for the purchase of keep-whole volumes at a specific price and is a component of a broader regional arrangement. The contract price is designed to share a portion of the frac spread with the producer and as a result, the amounts reflected for the obligation exceed the cost of purchasing the keep-whole volumes at a market price. The contract is considered an embedded derivative; see Note 6 of the accompanying Notes to Consolidated Financial Statements included in Item 8 for the fair value of the frac spread sharing component.

(5) Represents amounts due under a product supply agreement (see Note 5 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K).

(6) Excludes accretion expense of $15.6 million. The total amount to be paid is approximately $19.7 million.

Off-Balance Sheet Arrangements

We do not engage in off-balance sheet financing activities.

Effects of Inflation

Inflation did not have a material impact on our results of operations for the years ended December 31, 2010, 2009 or 2008. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment. It may also increase the costs of labor and supplies. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher fees.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

The policies and estimates discussed below are considered by management to be critical to an understanding of our financial statements, because their application requires the most significant judgments from management in estimating matters for financial reporting that are inherently uncertain. See Note 2 of the accompanying Notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K for additional information on these policies and estimates, as well as a discussion of additional accounting policies and estimates.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Intangible Assets		
Intangible assets are comprised of customer contracts and relationships acquired in business combinations, recorded under the purchase method of accounting at their estimated fair values at the date of acquisition. Using relevant information and assumptions, management determines the fair value of acquired identifiable intangible assets.	The fair value of customer contracts is generally calculated using the income approach. The key assumptions include contract renewals, economic incentives to retain customers, historical volumes, current and future capacity of the gathering system, pricing volatility, and the discount rate.	If the actual results differ significantly from the assumptions used to determine the fair value and economic lives of intangible assets, then a significant impairment charge could be recorded (see *Impairment of Long-Lived Assets* below) or amortization expense could increase.
	Amortization of intangibles with definite lives is calculated using the straight-line method over the estimated useful life of the intangible asset. The estimated economic life is determined by assessing the life of the assets to which the contracts and relationships relate, likelihood of renewals, the projected reserves, competitive factors, regulatory or legal provisions, and maintenance and renewal costs.	
Impairment of Long-Lived Assets		
Management evaluates our long-lived assets, including intangibles, for impairment when events or changes in circumstances warrant such a review. A long-lived asset group is considered impaired when the estimated undiscounted cash flows from such asset group are less than the asset group's carrying value. In that event, a loss is recognized to the extent that the carrying value exceeds the fair value of the long-lived asset group.	Management considers the volume of reserves behind the asset and future NGL product and natural gas prices to estimate cash flows for each asset group. The amount of additional reserves developed by future drilling activity depends, in part, on expected commodity prices. Projections of reserves, drilling activity and future commodity prices are inherently subjective and contingent upon a number of variable factors, many of which are difficult to forecast.	As of December 31, 2010, there were no indicators of impairment for any of our asset groups. A significant variance in any of these assumptions or factors could materially affect future cash flows, which could result in the impairment of an asset. A 10% decrease in the estimated future cash flows used in our impairment analysis would not indicate a potential impairment in any of our asset groups.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Impairment of Goodwill		
Goodwill is the cost of an acquisition less the fair value of the net assets of the acquired business. We evaluate goodwill for impairment annually as of November 30, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount.	Management determines the fair value of our reporting units using the income and market approaches. These approaches are also used when allocating the purchase price to acquired assets and liabilities. These types of analyses require us to make assumptions and estimates regarding industry and economic factors such as relevant commodity prices and production volumes. It is our policy to conduct impairment testing based on our current business strategy in light of present industry and economic conditions, as well as future expectations. Management was also required to make certain assumptions when identifying the reporting units and determining the amount of goodwill allocated to each reporting unit. The method of allocating goodwill resulting from the Merger involved estimating the fair value of the reporting units and allocating the purchase price of the Merger to each reporting unit. Goodwill was then calculated for each reporting unit as the excess of the allocated purchase price over the estimated fair value of the net assets.	As a result of the goodwill impairment testing completed in 2010, we recorded no impairment expense. The fair value of each reporting unit with goodwill was significantly in excess of its carrying value.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Impairment of Equity Investments		
We evaluate our equity method investments for impairment whenever events or changes in circumstances indicate, in management's judgment, that the carrying value of such investment may have experienced a decline in value. When evidence of an other-than-temporary loss in value has occurred, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred.	Our impairment loss calculations require management to apply judgment in estimating future cash flows and asset fair values, including forecasting useful lives of the assets, assessing the probability of differing estimated outcomes, and selecting the discount rate that reflects the risk inherent in future cash flows. We assess the fair value of our equity method investments using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models.	Management determined that there were no material events or changes in circumstances that would indicate an other-than-temporary decline in value of our investment in Centrahoma.
Accounting for Share-Based Compensation		
Our long-term incentive plans permit the grant of restricted units, phantom units, unit options and substitute awards. In April 2010, the General Partner's board of directors (the "Board") granted 282,000 phantom units to our senior executives and other key employees that will vest in equal installments on January 31, 2011 and January 31, 2012, subject to the relative ranking of the Partnership's total unitholder return over a three-year calendar period compared to the total unitholder return of a defined group of peer companies over the same period ("Market Criteria") and subject to the Board's discretion that can be exercised based on unspecified performance factors ("Performance Criteria").	We must exercise significant judgment and make several assumptions to estimate the fair value of the awards based on the Market Criteria. This includes determining the appropriate valuation methodology and the related inputs such as the expected volatility of the market price of our common units, the expected volatility of the market price of the common units or common stock of the peer companies, and the correlation between changes in the market price of our common units and those of the peer companies. We utilize a Monte Carlo simulation model which is a commonly accepted methodology for valuing this type of award. We utilized historical volatilities and correlation factors as the key inputs to this model.	If we had used a different valuation methodology or different assumptions regarding expected volatilities and correlations, the estimated fair value and related compensation expense of the phantom units may have been significantly different. Compensation expense could also increase or decrease significantly in future periods if the Board adjusts the number of units that vest based on the Performance Criteria.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Accounting for Share-Based Compensation (continued)		
The Market Criteria must be considered in determining the grant-date fair value of the award. The Performance Criteria do not affect the fair value of the awards but do impact the recognition of expense as compensation expense is only recognized for those awards that are expected to vest.	We have also exercised judgment in assuming that the Board will not increase or decrease the number of units that vest based on the Performance Criteria as there is no basis to conclude that it is probable that any adjustment to the vesting will be made.	
Accounting for Risk Management Activities and Derivative Financial Instruments		
Our derivative financial instruments are recorded at fair value in the accompanying Consolidated Balance Sheets. Changes in fair value and settlements are reflected in our earnings in the accompanying Consolidated Statements of Operations as gains and losses related to revenue, purchased product costs, facility expenses, interest income and/or miscellaneous income.	When available, quoted market prices or prices obtained through external sources are used to determine a financial instrument's fair value. The valuation of Level 2 financial instruments is based on quoted market prices for similar assets and liabilities in active markets and other inputs that are observable. However, for other financial instruments for which quoted market prices are not available, the fair value is based on inputs that are largely unobservable. These instruments are classified as Level 3 under the fair value hierarchy. The fair value of these instruments are determined based on pricing models developed primarily from historical and expected correlations with quoted market prices. All fair value measurements are appropriately adjusted for nonperformance risk.	If the assumptions used in the pricing models for our Level 2 and 3 financial instruments are inaccurate or if we had used an alternative valuation methodology, the estimated fair value may have been different, and we may be exposed to unrealized losses or gains that could be material. A 10% difference in our estimated fair value of Level 2 and 3 derivatives at December 31, 2010 would have affected net income before tax by approximately $13.7 million for the year ended December 31, 2010.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Variable Interest Entities		
We evaluate all legal entities in which we hold an ownership or other pecuniary interest to determine if the entity is a variable interest entity ("VIE"). Our interests in a VIE are referred to as variable interests. Variable interests can be contractual, ownership, or other pecuniary interests in an entity that change with changes in the fair value of the VIE's assets. When we conclude that we hold a variable interest in a VIE we must determine if we are the entity's primary beneficiary. A primary beneficiary is deemed to have a controlling financial interest in a VIE. This controlling financial interest is evidenced by both (a) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses that could potentially be significant to the VIE or the right to receive benefits that could potentially be significant to the VIE. We consolidate any VIE when we determine that we are the primary beneficiary. We must disclose the nature of any variable interests in a VIE that is not consolidated.	Significant judgment is exercised in determining that a legal entity is a VIE and in evaluating our interest in a VIE. We use primarily qualitative analysis to determine if an entity is a VIE. We evaluate the entity's need for continuing financial support; the equity holder's lack of a controlling financial interest; and/or if an equity holder's voting interests are disproportionate to its obligation to absorb expected losses or receive residual returns. We evaluate our variable interests in a VIE to determine whether we are the primary beneficiary. We use primarily qualitative analysis to determine if we are deemed to have a controlling financial interest in the VIE. We continually monitor our interests in legal entities for changes in the design or activities of an entity and changes in our interests, including our status as the primary beneficiary to determine if the changes require us to revise our previous conclusions.	MarkWest Liberty Midstream and MarkWest Pioneer are VIEs and we are considered the primary beneficiary; we have a traditional controlling financial interest in the Wirth Gathering Partnership and the Bright Star Partnership, which are less-than wholly-owned. All of these entities are consolidated subsidiaries. Changes in the design or nature of the activities of any of these entities, or our involvement with an entity may require us to reconsider our conclusions on the entity's status as a VIE and/or our status as the primary beneficiary. Such reconsideration could result in the deconsolidation of the affected subsidiary. The deconsolidation of a subsidiary would have a significant impact on our financial statements. We account for our ownership interest in Centrahoma under the equity method and have determined it is not a VIE. However, changes in the design or nature of the activities of the entity may require us to reconsider our conclusions. Such reconsideration would require the identification of the variable interests in the entity and a determination on which party is the entity's primary beneficiary. If Centrahoma were considered a VIE and we were determined to be the primary beneficiary, the change could cause us to consolidate the entity. The consolidation of an entity that is currently accounted for under the equity method could have a significant impact on our financial statements.

Recent Accounting Pronouncements

Refer to Note 2—*Recent Accounting Pronouncements* of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for information regarding recent accounting pronouncements.

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

Market risk includes the risk of loss arising from adverse changes in market rates and prices. We face market risk from commodity price changes and, to a lesser extent, interest rate changes and nonperformance by our customers and counterparties.

Commodity Price Risk

NGL and natural gas prices are volatile and are impacted by changes in fundamental supply and demand, as well as market uncertainty, availability of NGL transportation and fractionation capacity and a variety of additional factors that are beyond our control. Our profitability is directly affected by prevailing commodity prices primarily as a result of processing or conditioning at our processing plants or third-party processing plants, purchasing and selling, or gathering and transporting volumes of natural gas at index-related prices and the cost of third-party transportation and fractionation services. To the extent that commodity prices influence the level of drilling activity, such prices also affect profitability. To protect ourselves financially against adverse price movements and to maintain more stable and predictable earnings so that we can meet our cash distribution objectives, debt service and capital expenditures, we execute a hedging strategy governed by the risk management policy approved by the Board. We have a committee comprised of senior management that oversees risk management activities, continually monitors the risk management program and adjusts our strategy as conditions warrant. We enter into certain derivative contracts to reduce the risks associated with unfavorable changes in the prices of natural gas, NGLs and crude oil. Derivative contracts utilized are swaps, options and fixed price forward contracts traded on the OTC market. The risk management policy does not allow speculative derivative contracts.

To mitigate our cash flow exposure to fluctuations in the price of NGLs, we have entered into derivative financial instruments relating to the future price of NGLs and crude oil. Generally we hedge our NGL price risk using crude oil as NGL financial markets lack adequate liquidity and historically there has been a strong relationship between changes in NGL and crude oil prices. The pricing relationship between NGLs and crude oil may vary in certain periods because crude oil pricing is generally based on worldwide demand and the level of production of major crude oil exporting countries while NGL prices are correlated to North America supply and petrochemical demand. In periods where NGL prices and crude oil prices are not consistent with the historical relationship, we incur increased risk and additional gains or losses. We enter into NGL derivative contracts when adequate market liquidity exists.

To mitigate our cash flow exposure to fluctuations in the price of natural gas, we primarily utilize derivative financial instruments relating to the future price of natural gas and take into account the partial offset of our long and short gas positions resulting from normal operating activities.

As a result of our current derivative positions, we have mitigated a portion of our expected commodity price risk through the fourth quarter of 2013. For entities that are not wholly owned by us, commodity risk is mitigated only for our ownership interest. We would be exposed to additional commodity risk in certain situations such as if producers under deliver or over deliver product or when processing facilities are operated in different recovery modes. In the event we have derivative positions in excess of the product delivered or expected to be delivered, the excess derivative positions may be terminated.

We enter into derivative contracts primarily with financial institutions that are participating members of the Credit Facility as collateral is not posted by us as the participating members have a collateral position in substantially all of our wholly-owned assets. All of our financial derivative positions are currently with participating bank group members. Management conducts a standard credit review on counterparties and we have agreements containing collateral requirements. For all participating bank group members, collateral requirements do not exist when a derivative contract favors us. We use standardized agreements that allow for offset of positive and negative exposures (master netting arrangements).

Outstanding Derivative Contracts

The following tables provide information on the volume of our derivative activity for positions related to long liquids and keep-whole price risk at December 31, 2010, including the weighted average prices ("WAVG"):

WTI Crude Collars	Volumes (Bbl/d)	WAVG Floor (Per Bbl)	WAVG Cap (Per Bbl)	Fair Value (in thousands)
2011	1,659	$67.57	$85.05	$(6,826)
2012	2,139	72.34	93.11	(6,072)
2013	836	80.00	98.25	(991)

WTI Crude Puts	Volumes (Bbl/d)	WAVG Floor (Per Bbl)	Fair Value (in thousands)
2011	1,818	$80.00	$1,676

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)	Fair Value (in thousands)
2011	3,753	$82.98	$(14,375)
2012	4,813	84.54	(15,899)
2013	1,510	83.86	(4,718)

Natural Gas Swaps	Volumes (MMBtu/d)	WAVG Price (Per MMBtu)	Fair Value (in thousands)
2011	1,210	$5.38	$ (485)
2012	4,650	5.62	(1,421)
2013	980	5.13	(50)

The following tables provide information on the volume of our taxable subsidiary's commodity derivative activity for positions related to keep-whole price risk at December 31, 2010, including the WAVG:

WTI Crude Collars	Volumes (Bbl/d)	WAVG Floor (Per Bbl)	WAVG Cap (Per Bbl)	Fair Value (in thousands)
2012	646	$70.00	$91.85	$(2,143)

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)	Fair Value (in thousands)
2011	3,398	$86.90	$(7,950)
2012	1,840	86.93	(4,557)
2013	442	85.20	(1,203)

Natural Gas Swaps	Volumes (MMBtu/d)	WAVG Price (Per MMBtu)	Fair Value (in thousands)
2011	17,941	$8.23	$(22,595)
2012	13,801	6.07	(4,364)
2013	1,801	5.57	(108)

The following table provides information on the derivative positions related to long liquids and keep-whole price risk that we have entered into subsequent to December 31, 2010, including the WAVG:

WTI Crude Collars	Volumes (Bbl/d)	WAVG Floor (Per Bbl)	WAVG Cap (Per Bbl)
2013	1,286	$86.70	$106.57

The following tables provide information on the derivative positions of our taxable subsidiary related to keep-whole price risk that we have entered into subsequent to December 31, 2010, including the WAVG:

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)
2013	862	$99.00

Natural Gas Swaps	Volumes (MMBtu/d)	WAVG Price (Per MMBtu)
2013	4,782	$ 5.24

Embedded Derivatives in Commodity Contracts. We have a commodity contract with a producer in the Appalachia region that creates a floor on the frac spread for gas purchases of 9,000 Dth/d. The primary term of the commodity contract, a component of a broader regional arrangement, expired on December 31, 2009 but the producer exercised its right to extend the processing agreement and the commodity contract through the first quarter of 2015. In February 2011, we executed agreements with the producer to extend the processing agreement and the commodity contract through 2022. The fair value of the commodity contract is marked based on an index price through *Derivative loss related to purchased product costs*. As of December 31, 2010, the estimated fair value of this contract was a liability of $36.0 million.

We have a commodity contract that gives us an option to fix a component of the utilities cost to an index price on electricity at one of our plant locations through the fourth quarter of 2014. The value of the derivative component of this contract is marked to market through *Derivative (gain) loss related to facility expenses*. As of December 31, 2010, the estimated fair value of this contract was an asset of $1.0 million.

Interest Rate Risk

Our primary interest rate risk exposure results from the revolving portion of the Partnership Credit Agreement that has a borrowing capacity of $705.0 million. As of February 18, 2011, we have $70.4 million of borrowings outstanding on the Credit Facility. The debt related to this agreement bears interest at variable rates that are tied to either the U.S. prime rate or LIBOR at the time of borrowing.

We may make use of interest rate swap agreements in the future to adjust the ratio of fixed and floating rates in our debt portfolio. In July 2009, we entered into fixed-to-variable interest rate swap agreements having a combined notional principal amount of $275.0 million. The hedges were intended to hedge against changes in fair value due to changes in the benchmark interest rate (one-month

LIBOR). We hedged a portion of our 2014 Senior Notes that were redeemed in the fourth quarter of 2010. All outstanding interest rate swaps were settled in January 2010.

Long-Term Debt	Interest Rate	Lending Limit	Due Date	Outstanding at December 31, 2010(1)
Credit Facility	Variable	$705.0 million	July 2015	$ 0 million
2016 Senior Notes	Fixed	$275.0 million	July 2016	$275.0 million
2018 Senior Notes	Fixed	$500.0 million	April 2018	$500.0 million
2020 Senior Notes	Fixed	$500.0 million	November 2020	$500.0 million

(1) Balances do not give effect to the 2021 Senior Notes offering and the tender offers for the 2016 Senior Notes and 2018 Senior Notes completed subsequent to December 31, 2010. See Note 30 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for information regarding the offering and tender offers.

Based on our overall interest rate exposure at December 31, 2010, a hypothetical increase or decrease of one percentage point in interest rates applied to borrowings under our Credit Facility would not have an impact on our earnings over a 12-month period. Based on our overall interest rate exposure at February 18, 2011, a hypothetical increase or decrease of one percentage point in interest rates applied to borrowings under our Credit Facility would change earnings by approximately $0.7 million over a 12-month period.

Credit Risk

We are subject to risk of loss resulting from nonpayment or nonperformance by the counterparties to our derivative contracts. Our credit exposure related to commodity derivative instruments is represented by the fair value of contracts with a net positive fair value at the reporting date. These outstanding instruments expose us to credit loss in the event of nonperformance by the counterparties to the agreements. Should the creditworthiness of one or more of our counterparties decline, our ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted.

We are subject to risk of loss resulting from nonpayment by our customers to whom we provide midstream services or sell natural gas or NGLs. Our credit exposure related to these customers is represented by the value of our trade receivables. Where exposed to credit risk, we analyze the customer's financial condition prior to entering into a transaction or agreement, establish credit terms, and monitor the appropriateness of these terms on an ongoing basis. In the event of a customer default, we may sustain a loss and our cash receipts could be negatively impacted.

ITEM 8. Financial Statements and Supplementary Data

Index to Consolidated Financial Statements

All schedules have been omitted because they are not required or because the required information is contained in the financial statements or notes thereto.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
MarkWest Energy GP, L.L.C.
Denver, Colorado

We have audited the accompanying consolidated balance sheets of MarkWest Energy Partners, L.P. and subsidiaries (the "Partnership") as of December 31, 2010 and 2009, and the related consolidated statements of operations, changes in equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of MarkWest Energy Partners, L.P. and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2011 expressed an unqualified opinion on the Partnership's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 28, 2011

MARKWEST ENERGY PARTNERS, L.P.
CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents ($2,913 and $21,942, respectively)	$ 67,450	$ 97,752
Receivables, net ($43,783 and $22,033, respectively)	179,209	140,969
Inventories ($8,431 and $3,343, respectively)	23,432	29,075
Fair value of derivative instruments	4,345	8,821
Deferred income taxes	16,090	12,228
Other current assets ($272 and $327, respectively)	8,020	10,674
Total current assets	298,546	299,519
Property, plant and equipment ($849,986 and $494,918, respectively)	2,613,027	2,154,644
Less: accumulated depreciation ($38,169 and $11,324, respectively)	(294,003)	(173,000)
Total property, plant and equipment, net	2,319,024	1,981,644
Other long-term assets:		
Restricted cash ($28,001 and $0, respectively)	28,001	—
Investment in unconsolidated affiliate	28,688	29,633
Intangibles, net of accumulated amortization of $124,568 and $83,735, respectively	613,578	654,411
Goodwill	9,421	9,421
Deferred financing costs, net of accumulated amortization of $11,445 and $6,990, respectively	32,901	21,027
Deferred contract cost, net of accumulated amortization of $1,950 and $1,638, respectively	1,300	1,612
Fair value of derivative instruments	417	15,810
Other long-term assets ($383 and $314, respectively)	1,486	1,660
Total assets	$3,333,362	$3,014,737
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable ($5,945 and $2,745, respectively)	$ 122,473	$ 87,832
Accrued liabilities ($64,713 and $44,615, respectively)	153,869	137,687
Deferred income taxes	11	—
Fair value of derivative instruments	65,489	60,464
Total current liabilities	341,842	285,983
Deferred income taxes	10,427	11,034
Fair value of derivative instruments	66,290	62,519
Long-term debt, net of discounts of $1,566 and $39,417, respectively	1,273,434	1,170,072
Other long-term liabilities ($154 and $365, respectively)	105,349	105,736
Commitments and contingencies (see Note 19)		
Equity:		
MarkWest Energy Partners, L.P. partners' capital (71,440 and 66,275 common units issued and outstanding, respectively)	1,070,503	1,096,654
Non-controlling interest in consolidated subsidiaries	465,517	282,739
Total equity	1,536,020	1,379,393
Total liabilities and equity	$3,333,362	$3,014,737

Asset and liability amounts in parentheses represent the portion of the consolidated balance attributable to variable interest entities.

The accompanying notes are an integral part of these consolidated financial statements.

MARKWEST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per unit amounts)

	Year ended December 31,		
	2010	2009	2008
Revenue:			
Revenue	$1,241,563	$ 858,635	$1,060,662
Derivative (loss) gain	(53,932)	(120,352)	277,828
Total revenue	1,187,631	738,283	1,338,490
Operating expenses:			
Purchased product costs	578,627	408,826	615,902
Derivative loss related to purchased product costs	27,713	68,883	22,371
Facility expenses	151,449	126,977	103,682
Derivative (gain) loss related to facility expenses	(1,295)	(373)	644
Selling, general and administrative expenses	75,258	63,728	68,975
Depreciation	123,198	95,537	67,480
Amortization of intangible assets	40,833	40,831	38,483
Loss on disposal of property, plant and equipment	3,149	1,677	178
Accretion of asset retirement obligations	237	198	129
Impairment of goodwill and long-lived assets	—	5,855	36,351
Total operating expenses	999,169	812,139	954,195
Income (loss) from operations	188,462	(73,856)	384,295
Other income (expense):			
Earnings from unconsolidated affiliates	1,562	3,505	90
Impairment of unconsolidated affiliate	—	—	(41,449)
Gain on sale of unconsolidated affiliate	—	6,801	—
Interest income	1,670	349	3,769
Interest expense	(103,873)	(87,419)	(64,563)
Amortization of deferred financing costs and discount (a component of interest expense)	(10,264)	(9,718)	(8,299)
Derivative gain related to interest expense	1,871	2,509	—
Loss on redemption of debt	(46,326)	—	—
Miscellaneous income (expense), net	1,189	2,459	(241)
Income (loss) before provision for income tax	34,291	(155,370)	273,602
Provision for income tax expense (benefit):			
Current	7,655	8,072	15,032
Deferred	(4,466)	(50,088)	53,798
Total provision for income tax	3,189	(42,016)	68,830
Net income (loss)	31,102	(113,354)	204,772
Net (income) loss attributable to non-controlling interest	(30,635)	(5,314)	3,301
Net income (loss) attributable to the Partnership	$ 467	$(118,668)	$ 208,073
Net (loss) income attributable to the Partnership's common unitholders per common unit (Note 24):			
Basic	$ (0.01)	$ (1.97)	$ 4.02
Diluted	$ (0.01)	$ (1.97)	$ 4.02
Weighted average number of outstanding common units:			
Basic	70,128	60,957	51,013
Diluted	70,128	60,957	51,016
Cash distribution declared per common unit	$ 2.560	$ 2.560	$ 2.059

The accompanying notes are an integral part of these consolidated financial statements.

MARKWEST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY AND COMPREHENSIVE INCOME
(in thousands)

	MarkWest Energy Partners, L.P. Unitholders				
	Common Units	Partners' Capital	Accumulated Other Comprehensive Income	Non-controlling Interest	Total
December 31, 2007	22,861	$ 38,463	$ 928	$ 524,583	$ 563,974
Option exercises	98	375	—	—	375
Share-based compensation activity	14	11,560	—	—	11,560
Dividends paid	—	(4,338)	—	—	(4,338)
Distributions paid	—	(107,269)	—	(19,651)	(126,920)
Excess tax benefits related to share-based compensation	—	717	—	—	717
Acquisition of partially owned entity included as part of PQ Gathering Assets, L.L.C.	—	—	—	2,935	2,935
Other	—	—	—	1,032	1,032
Merger and Redemption:					
Redemption of MarkWest Hydrocarbon, Inc. common stock	(7,458)	(240,513)	—	—	(240,513)
Conversion of restricted stock to phantom units in connection with the Merger	(45)	—	—	—	—
Acquisition of General Partnership's non-controlling interest associated with the Merger	946	30,078	—	—	30,078
Purchase of non-controlling interest of MarkWest Energy Partners, L.P.	34,474	1,095,917	—	(502,297)	593,620
Issuance of units in public offering, net of offering costs	5,750	171,395	—	—	171,395
Net income (loss)	—	208,073	—	(3,301)	204,772
Realized gain on marketable securities, net of tax of $558	—	—	(928)	—	(928)
Comprehensive income					203,844
December 31, 2008	56,640	1,204,458	—	3,301	1,207,759
Share-based compensation activity	275	5,204	—	—	5,204
Distributions paid	—	(155,307)	—	(155)	(155,462)
Issuance of units in public offerings, net of offering costs	9,360	178,565	—	—	178,565
Contributions to MarkWest Liberty Midstream joint venture, net	—	(5,464)	—	200,000	194,536
Proceeds from sale of equity interest in joint venture, net	—	(1,846)	—	62,500	60,654
Transfer to non-controlling interest from sale of equity interest in joint venture, net of tax	—	(10,288)	—	11,779	1,491
Net (loss) income	—	(118,668)	—	5,314	(113,354)
December 31, 2009	66,275	1,096,654	—	282,739	1,379,393
Share-based compensation activity	278	12,087	—	—	12,087
Excess tax benefits related to share-based compensation	—	98	—	—	98
Distributions paid	—	(181,058)	—	(6,150)	(187,208)
Issuance of units in public offering, net of offering costs	4,887	142,255	—	—	142,255
Contributions to MarkWest Liberty Midstream joint venture, net	—	—	—	158,293	158,293
Net income	—	467	—	30,635	31,102
December 31, 2010	71,440	$1,070,503	$ —	$ 465,517	$1,536,020

The accompanying notes are an integral part of these consolidated financial statements.

MARKWEST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year ended December 31, 2010	2009	2008
Cash flows from operating activities:			
Net income (loss)	$ 31,102	$(113,354)	$ 204,772
Adjustments to reconcile net incomé (loss) to net cash provided by operating activities (net of acquisitions):			
Depreciation	123,198	95,537	67,480
Amortization of intangible assets	40,833	40,831	38,483
Impairment of goodwill and long-lived assets	—	5,855	36,351
Impairment of unconsolidated affiliate	—	—	41,449
Inventory lower of cost or market adjustment	—	—	6,678
Loss on redemption of debt	46,326	—	—
Amortization of deferred financing costs and discount	10,264	9,718	8,299
Accretion of asset retirement obligations	237	198	129
Amortization of deferred contract cost	312	312	312
Phantom unit compensation expense	15,319	7,448	11,348
Participation Plan compensation expense	—	—	4,545
Restricted stock compensation expense	—	—	75
Equity in earnings of unconsolidated affiliates	(1,562)	(3,505)	(90)
Gain on sale of unconsolidated affiliate	—	(6,801)	—
Distributions from unconsolidated affiliate	2,508	—	445
Unrealized loss (gain) on derivative instruments	28,475	227,920	(276,526)
Loss on disposal of property, plant and equipment	3,149	1,677	178
Deferred income taxes	(4,466)	(50,088)	53,798
Gain on sale of available for sale securities	—	—	(1,238)
(Gain) loss on sale of trading securities	—	(40)	762
Net sales of trading securities	—	552	2,400
Other	—	(2,740)	181
Changes in operating assets and liabilities, net of working capital acquired:			
Receivables	(37,090)	(33,133)	29,028
Inventories	5,710	6,245	(7,906)
Other current assets	2,654	1,074	39,430
Accounts payable and accrued liabilities	45,361	30,717	(34,072)
Other long-term assets	174	(2,808)	(1,126)
Other long-term liabilities	(176)	7,486	1,810
Net cash provided by operating activities	312,328	223,101	226,995
Cash flows from investing activities:			
Restricted cash	(28,001)	—	—
Capital expenditures	(458,668)	(486,623)	(575,298)
Acquisitions	—	—	(41,300)
Equity investments	—	(405)	(29,187)
Cash paid to acquire General Partnership's non-controlling interest	—	—	(21,484)
Cash paid in Merger for MarkWest Hydrocarbon, Inc. stock	—	—	(248,395)
Proceeds from sale of unconsolidated affiliate	—	25,000	—
Proceeds from sale of available for sale securities	—	—	6,226
Proceeds from disposal of property, plant and equipment	733	275	173
Net cash flows used in investing activities	(485,936)	(461,753)	(909,265)
Cash flows from financing activities:			
Proceeds from revolving credit facility	494,404	725,200	678,001
Payments of revolving credit facility	(553,704)	(850,600)	(548,801)
Proceeds from long-term debt	500,000	117,000	498,732
Payments of long-term debt	(375,000)	—	—
Payments of premiums on redemption of long-term debt	(9,732)	—	—
Payments for debt issuance costs, deferred financing costs and registration costs	(20,912)	(8,554)	(21,204)
Contributions to MarkWest Liberty Midstream joint venture, net	158,293	194,536	—
Proceeds from sale of equity interest in joint venture, net	—	60,654	—
Payments of SMR Liability	(1,354)	—	—
Proceeds from SMR Transaction	—	73,129	—
Proceeds from public offerings, net	142,255	178,565	171,395
Cash paid for taxes related to net settlement of share-based payment awards	(3,834)	(1,385)	(61)
Excess tax benefits related to share-based compensation	98	—	717
Exercise of stock options	—	—	375
Payments of dividends and distributions to common unitholders	(181,058)	(155,307)	(111,607)
Payments of distributions to non-controlling interest	(6,150)	(155)	(19,651)
Net cash flows provided by financing activities	143,306	333,083	647,896
Net (decrease) increase in cash	(30,302)	94,431	(34,374)
Cash and cash equivalents at beginning of year	97,752	3,321	37,695
Cash and cash equivalents at end of year	$ 67,450	$ 97,752	$ 3,321

The accompanying notes are an integral part of these consolidated financial statements.

MARKWEST ENERGY PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization

MarkWest Energy Partners, L.P. ("MarkWest Energy Partners") was formed in January 2002, as a Delaware limited partnership. MarkWest Energy Partners and its majority-owned subsidiaries (collectively, the "Partnership") are engaged in the gathering, transportation and processing of natural gas; the transportation, fractionation, marketing and storage of NGLs and the gathering and transportation of crude oil. The Partnership has established a significant presence in the Southwest through strategic acquisitions and strong organic growth opportunities stemming from those acquisitions. The Partnership is also the largest processor and fractionator of natural gas in the Appalachian Basin, one of the country's oldest natural gas producing regions. The Partnership also has a significant presence in the Marcellus Shale through a joint venture that is the largest processor of natural gas in this emerging resource play. Finally, the Partnership owns a crude oil transportation pipeline in Michigan. The Partnership's principal executive office is located in Denver, Colorado.

On February 21, 2008, MarkWest Energy Partners consummated the transactions contemplated by its plan of redemption and merger (the "Merger") with MarkWest Hydrocarbon, Inc. (the "Corporation" or "MarkWest Hydrocarbon") and MWEP, L.L.C., a wholly-owned subsidiary of the Partnership. A discussion of the Merger and its accounting impact on the Partnership is described in Note 3. The Merger was considered a downstream merger, whereby the Corporation was viewed as the surviving consolidated entity for accounting and financial purposes rather than the Partnership, which is the surviving consolidated entity for legal purposes. As such, the Merger was accounted for in the Corporation's consolidated financial statements as an acquisition of non-controlling interest using the purchase method of accounting. As a result, the historical and comparative consolidated financial statements of the surviving legal entity are those of the Corporation, the accounting acquirer, rather than those of the Partnership, the legal acquirer.

2. Summary of Significant Accounting Policies

Basis of Presentation

The Partnership's consolidated financial statements include all majority-owned or majority-controlled subsidiaries. In addition, MarkWest Liberty Midstream & Resources, L.L.C. ("MarkWest Liberty Midstream") and MarkWest Pioneer, L.L.C. ("MarkWest Pioneer"), variable interest entities for which the Partnership has been determined to be the primary beneficiary, are included in the consolidated financial statements (see Note 4 for further discussion of MarkWest Liberty Midstream and MarkWest Pioneer). All significant intercompany investments, accounts and transactions have been eliminated. Investments in which the Partnership exercises significant influence but does not control, or is not the primary beneficiary, are accounted for using the equity method. The accompanying consolidated financial statements include the accounts of the Partnership, and have been prepared in accordance with GAAP.

Non-Controlling Interest in Consolidated Subsidiaries

The Partnership owns a controlling operating interest in Wirth Gathering, a general partnership. The Partnership's equity interest was acquired as part of the acquisition of PQ Gathering Assets, L.L.C. ("PQ Assets"). The interests in Wirth Gathering, MarkWest Liberty Midstream and MarkWest Pioneer that are not owned by the Partnership have been recorded as *Non-controlling interest in consolidated subsidiaries* in the accompanying Consolidated Balance Sheets. The *Non-controlling interest in*

2. Summary of Significant Accounting Policies (Continued)

consolidated subsidiaries amounts recorded in 2010 and 2009 relate to all three of these entities and the amount recorded in 2008 relates primarily to Wirth Gathering.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates affect, among other items, valuing identified intangible assets; determining the fair value of derivative instruments; valuing inventory; evaluating impairments of long-lived assets, goodwill and equity investments; establishing estimated useful lives for long-lived assets; recognition of share-based compensation expense; estimating revenues and expense accruals; valuing asset retirement obligations; and in determining liabilities, if any, for legal contingencies.

Cash and Cash Equivalents

The Partnership considers investments in highly liquid financial instruments purchased with an original maturity of 90 days or less to be cash equivalents. Such investments include money market accounts.

Restricted Cash

Restricted cash includes cash and investments that must be held in escrow until related project spending occurs and the third party releases the restriction. Restricted cash related to projects that will be completed over a period longer than twelve months is classified as a long-term asset in the Consolidated Balance Sheets.

Inventories

Inventories, which consist primarily of natural gas, propane, other NGLs and spare parts, are valued at the lower of weighted average cost or market. Processed natural gas inventories include material, labor and overhead. Shipping and handling costs related to purchases of natural gas and NGLs are included in inventory.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost. Expenditures that extend the useful lives of assets are capitalized. Repairs, maintenance and renewals that do not extend the useful lives of the assets are expensed as incurred. Interest costs for the construction or development of long-lived assets are capitalized and amortized over the related asset's estimated useful life. Leasehold improvements are depreciated over the shorter of the useful life or lease term. Depreciation is provided, principally on the straight-line method, over a period of 20 to 25 years for all assets, with the exception of miscellaneous equipment and vehicles that are depreciated over a period of three to ten years.

2. Summary of Significant Accounting Policies (Continued)

Asset Retirement Obligations

An asset retirement obligation ("ARO") is a legal obligation associated with the retirement of tangible long-lived assets that generally result from the acquisition, construction, development or normal operation of the asset. AROs are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made, and added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability is determined using a risk free interest rate, and increases due to the passage of time based on the time value of money until the obligation is settled. The Partnership recognizes a liability of a conditional ARO as soon as the fair value of the liability can be reasonably estimated. A conditional ARO is defined as an unconditional legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity.

Property, Plant and Equipment for FERC Regulated Assets

Depreciation is generally computed over the asset's estimated useful life using the straight-line method. The composite weighted-average depreciation rates were 4% for all periods presented. When the Partnership retires its regulated property, plant and equipment, it charges the original cost plus the cost of retirement, less salvage value, to accumulated depreciation and amortization.

Allowance for Funds Used During Construction

Allowance for funds used during construction ("AFUDC"), which represents the estimated debt and equity costs of capital funds necessary to finance the construction and expansion of regulated facilities, consists of an equity component and an interest expense component. The equity component is a non-cash item. AFUDC is capitalized as a component of *Property, plant and equipment*, with offsetting credits to the Consolidated Statements of Operations included in *Miscellaneous income (expense), net* for the equity component and *Interest expense* for the interest component. After construction is completed, the Partnership is permitted to recover these costs through inclusion in the rate base and in the depreciation provision. The total amount of AFUDC included in the Consolidated Statements of Operations was zero for the year ended December 31, 2010, $5.0 million for the year ended December 31, 2009 (an equity component of $2.8 million and an interest expense component of $2.2 million) and zero for the year ended December 31, 2008.

Accounting for Sales of Real Estate

The Partnership evaluates transactions involving the sale of assets to determine if they are, in-substance, the sale of real estate. Tangible assets may be considered real estate if the costs to relocate them for use in a different location exceeds 10% of the asset's fair value. Financial assets, primarily in the form of ownership interests in an entity, may be in-substance real estate based on the significance of the real estate in the entity. Sales of real estate are not considered consummated if the Partnership maintains an interest in the asset after it is sold, or has certain other forms of continuing involvement. Significant judgment is required to determine if a transaction is a sale of real estate and if a transaction has been consummated. If a sale of real estate is not considered consummated, the Partnership cannot record the transaction as a sale and must account for the transaction under an alternative method of accounting such as a financing or leasing arrangement. During 2009, the

2. Summary of Significant Accounting Policies (Continued)

Partnership entered into two transactions which were accounted for as real estate. The sale of the steam methane reformer ("SMR") was not considered a sale of real estate due to the Partnership's continuing involvement, and was accounted for as a financing arrangement. The Partnership's sale of equity interest in MarkWest Pioneer was considered the sale of in-substance real estate. See Note 5 and Note 4, respectively, for a description of each transaction and its impact on the financial statements.

Investment in Unconsolidated Affiliates

Equity investments in which the Partnership exercises significant influence, but does not control and is not the primary beneficiary, are accounted for using the equity method, and are reported in *Investment in unconsolidated affiliate* in the accompanying Consolidated Balance Sheets. Refer to Note 14 for further discussion of the Partnership's equity investments.

The Partnership believes the equity method is an appropriate means for it to recognize increases or decreases measured by GAAP in the economic resources underlying the investments. Regular evaluation of these investments is appropriate to evaluate any potential need for impairment. It uses the following types of evidence of a loss in value to identify a loss in value of an investment that is other than a temporary decline. Examples of an other-than-temporary loss in value may be identified by:

- The potential inability to recover the carrying amount of the investment;
- The estimated fair value of an investment that is less than its carrying amount. Factors considered include the length of time in which the market has been less than cost and the intent and ability to retain the investment to sufficiently allow for any recovery; and
- Other operational or external factors including economic trends and projected financial performance that cause management to believe the investment may be worth less than otherwise accounted for by using the equity method.

Intangible Assets

The Partnership's intangible assets are comprised of customer contracts and relationships acquired in business combinations, recorded under the purchase method of accounting at their estimated fair values at the date of acquisition. Using relevant information and assumptions, management determines the fair value of acquired identifiable intangible assets. Fair value is generally calculated as the present value of estimated future cash flows using a risk-adjusted discount rate. The key assumptions include probability of contract renewals, economic incentives to retain customers, historical volumes, current and future capacity of the gathering system, pricing volatility, and the discount rate. Amortization of intangibles with definite lives is calculated using the straight-line method over the estimated useful life of the intangible asset. The estimated economic life is determined by assessing the life of the assets to which the contracts and relationships relate, likelihood of renewals, the projected reserves, competitive factors, regulatory or legal provisions, and maintenance and renewal costs.

Goodwill

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. The Partnership evaluates goodwill for impairment annually as of November 30, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a

2. Summary of Significant Accounting Policies (Continued)

reporting unit is less than its carrying amount. Impairment testing of goodwill consists of a two-step process. The first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss.

Impairment of Long-Lived Assets

The Partnership's policy is to evaluate whether there has been a permanent impairment in the value of long-lived assets when certain events indicate that the remaining balance may not be recoverable. The Partnership evaluates the carrying value of its property, plant and equipment on at least a segment level and at lower levels where the cash flows for specific assets can be identified and are largely independent from other asset groups. A long-lived asset group is considered impaired when the estimated undiscounted cash flows from such asset group are less than the asset group's carrying value. In that event, a loss is recognized to the extent that the carrying value exceeds the fair value of the long-lived asset group. Fair value is determined primarily using estimated discounted cash flows. Management considers the volume of reserves behind the asset and future NGL product and natural gas prices to estimate cash flows. The amount of additional reserves developed by future drilling activity depends, in part, on expected natural gas prices. Projections of reserves, drilling activity and future commodity prices are inherently subjective and contingent upon a number of variable factors, many of which are difficult to forecast. Any significant variance in any of these assumptions or factors could materially affect future cash flows, which could result in the impairment of an asset group.

For assets identified to be disposed of in the future, the carrying value of these assets is compared to the estimated fair value, less the cost to sell, to determine if impairment is required. Until the assets are disposed of, an estimate of the fair value is re-determined when related events or circumstances change.

Deferred Financing Costs

Deferred financing costs are amortized over the estimated lives of the related obligations or, in certain circumstances, accelerated if the obligation is refinanced, using the effective interest method.

Deferred Contract Costs

The Partnership may pay consideration to a producer upon entering a long-term arrangement to provide midstream services to the producer. In such cases, the amount of consideration paid is recorded as *Deferred contract cost, net of accumulated amortization* on the accompanying Consolidated Balance Sheets and is amortized over the term of the arrangement.

Derivative Instruments

Derivative instruments (including derivative instruments embedded in other contracts) are recorded at fair value and included in the consolidated balance sheet as assets or liabilities. Assets and liabilities related to derivative instruments with the same counterparty are not netted in the consolidated balance sheet. The Partnership discloses the fair value of substantially all of its derivative instruments separate

2. Summary of Significant Accounting Policies (Continued)

from other assets and liabilities under the caption *Fair value of derivative instruments* in the Consolidated Balance Sheet, inclusive of option premiums (net of amortization). The fair value of derivatives related to long-term debt is included as a component of *Long-term debt* in the Consolidated Balance Sheet.

Changes in the fair value of derivative instruments are reported in the Statement of Operations in accounts related to the item economically hedged. Substantially all derivative instruments were marked to market through *Revenue*, *Purchased product costs*, *Facility expenses*, *Interest expense*, or *Miscellaneous income (expense), net*. Revenue gains and losses relate to contracts utilized to hedge the cash flow for the sale of a product and the amortization of associated option premiums. Option premiums are amortized over the effective term of the corresponding option contract. Purchased product costs gains and losses relate to contracts utilized to hedge costs, typically in a keep-whole arrangement. Facility expenses gains and losses relate to a contract utilized to hedge electricity costs. Interest expense gains relate to contracts to manage the interest rate risk associated with the fair value of its fixed rate borrowings. Miscellaneous income (expense), net relate to changes in the fair value of certain embedded put options (see Note 6 and Note 17). Changes in risk management activities are reported in cash flow from operating activities on the accompanying Consolidated Statements of Cash Flows.

During 2010, 2009 and 2008 the Partnership did not designate any hedges or designate any contracts as normal purchases and normal sales.

Fair Value of Financial Instruments

Management believes the carrying amount of financial instruments, including cash, accounts receivable, accounts payable, and accrued expenses approximates fair value because of the short-term maturity of these instruments. The recorded value of the amounts outstanding under the Credit Facility approximate fair value due to the variable interest rate that reflects current market conditions. Derivative instruments are recorded at fair value, based on available market information (see Note 6). The following table shows the carrying value and related fair value of financial instruments that are not recorded in the financial statements at fair value as of December 31, 2010 and 2009 (amounts in thousands).

	December 31, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$1,273,434	$1,333,875	$1,170,072	$1,212,238
SMR Liability	95,784	125,600	95,210	95,210
Total	$1,369,218	$1,459,475	$1,265,282	$1,307,448

Fair Value Measurement

The Partnership adopted guidance related to fair value measurements, effective January 1, 2008, except for certain provisions related to non-financial assets and liabilities that were deferred by the FASB and adopted as of January 1, 2009. The guidance defines fair value, establishes a framework for measuring fair value, establishes a three-level valuation hierarchy, and expands the disclosures about fair value measurements.

2. Summary of Significant Accounting Policies (Continued)

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 to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2—inputs to the valuation methodology 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 to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement.

The determination to classify a financial instrument with Level 3 of the valuation hierarchy is based upon the significance of the unobservable inputs to the overall fair value measurement. However, Level 3 financial instruments typically include, in addition to the unobservable or Level 3 inputs, observable inputs (that is, inputs that are actively quoted and can be validated to external sources); accordingly, the gains and losses for Level 3 financial instruments include changes in fair value due in part to observable inputs that are part of the valuation methodology. Level 3 financial instruments include interest rate swaps, crude oil options, all NGL derivatives, the embedded derivatives in commodity contracts, and the embedded put options discussed in Note 6 and Note 17, as they have significant unobservable inputs.

The methods and assumptions described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while the Partnership believes its valuation methods are appropriate and consistent with other market participants, 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. For further discussion see Note 7.

Revenue Recognition

The Partnership generates the majority of its revenues from natural gas gathering, transportation and processing; NGL transportation, fractionation, marketing and storage; and crude oil gathering and transportation. It enters into a variety of contract types. In many cases, the Partnership provides services under contracts that contain a combination of more than one of the arrangements described below. The Partnership provides services under the following different types of arrangements:

- *Fee-based arrangements*—Under fee-based arrangements, the Partnership receives a fee or fees for one or more of the following services: gathering, processing and transmission of natural gas; transportation, fractionation and storage of NGLs; and gathering and transportation of crude oil. The revenue the Partnership earns from these arrangements is generally directly related to the volume of natural gas, NGLs or crude oil that flows through the Partnership's systems and facilities and is not directly dependent on commodity prices. In certain cases, the Partnership's arrangements provide for minimum annual payments or fixed demand charges.

2. Summary of Significant Accounting Policies (Continued)

- *Percent-of-proceeds arrangements*—Under percent-of-proceeds arrangements, the Partnership gathers and processes natural gas on behalf of producers, sells the resulting residue gas, condensate and NGLs at market prices and remits to producers an agreed-upon percentage of the proceeds. In other cases, instead of remitting cash payments to the producer, the Partnership will deliver an agreed-upon percentage of the residue gas and NGLs to the producer and sell the volumes the Partnership keeps to third parties at market prices.
- *Percent-of-index arrangements*—Under percent-of-index arrangements, the Partnership will purchase natural gas at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount or (3) a percentage discount to a specified index price less an additional fixed amount. The Partnership will then gather and deliver the natural gas to pipelines where the Partnership will resell the natural gas at the index price, or at a different percentage discount to the index price.
- *Keep-whole arrangements*—Under keep-whole arrangements, the Partnership gathers natural gas from the producer, processes the natural gas and sells the resulting condensate and NGLs to third parties at market prices. Because the extraction of the condensate and NGLs from the natural gas during processing reduces the Btu content of the natural gas, the Partnership must either purchase natural gas at market prices for return to producers or make cash payment to the producers equal to the energy content of this natural gas. Certain keep-whole arrangements also have provisions that require the Partnership to share a percentage of the keep-whole profits with the producers based on the oil to gas ratio or the NGL to gas ratio.
- *Settlement margin*—Typically, the Partnership is allowed to retain a fixed percentage of the volume gathered to cover the compression fuel charges and deemed-line losses. To the extent the Partnership's gathering systems are operated more or less efficiently than specified per contract allowance, the Partnership is entitled to retain the benefit or loss for its own account.

In many cases, the Partnership provides services under contracts that contain a combination of more than one of the arrangements described above. The terms of the Partnership's contracts vary based on gas quality conditions, the competitive environment when the contracts are signed and customer requirements. Under all of the arrangements, revenue is recognized at the time the product is delivered and title is transferred. It is upon delivery and title transfer that the Partnership meets all four revenue recognition criteria, and it is at such time that the Partnership recognizes revenue.

The Partnership's assessment of each of the four revenue recognition criteria as they relate to its revenue producing activities is as follows:

Persuasive evidence of an arrangement exists. The Partnership's customary practice is to enter into a written contract, executed by both the customer and the Partnership.

Delivery. Delivery is deemed to have occurred at the time the product is delivered and title is transferred, or in the case of fee-based arrangements, when the services are rendered.

The fee is fixed or determinable. The Partnership negotiates the fee for its services at the outset of its fee-based arrangements. In these arrangements, the fees are nonrefundable. For other arrangements, the amount of revenue is determinable when the sale of the applicable product has been completed upon delivery and transfer of title.

2. Summary of Significant Accounting Policies (Continued)

Collectibility is reasonably assured. Collectibility is evaluated on a customer-by-customer basis. New and existing customers are subject to a credit review process, which evaluates the customers' financial position (e.g. cash position and credit rating) and their ability to pay. If collectibility is not considered reasonably assured at the outset of an arrangement in accordance with the Partnership's credit review process, revenue is recognized when the fee is collected.

The Partnership enters into revenue arrangements where it sells customer's gas and/or NGLs and depending on the nature of the arrangement acts as the principal or agent. Revenue from such sales is recognized gross where the Partnership acts as the Principal, as the Partnership takes title to the gas and/or NGLs, has physical inventory risk and does not earn a fixed amount. Revenue is recognized net when the Partnership earns a fixed amount and does not take ownership of the gas and/or NGLs.

Amounts billed to customers for shipping and handling are included in *Revenue*. Shipping and handling costs associated with product sales are included in operating expenses. Taxes collected from customers and remitted to the appropriate taxing authority are excluded from revenue.

Revenue and Expense Accruals

The Partnership routinely makes accruals based on estimates for both revenues and expenses due to the timing of compiling billing information, receiving certain third party information and reconciling the Partnership's records with those of third parties. The delayed information from third parties includes, among other things, actual volumes purchased, transported or sold, adjustments to inventory and invoices for purchases, actual natural gas and NGL deliveries and other operating expenses. The Partnership makes accruals to reflect estimates for these items based on its internal records and information from third parties. Estimated accruals are reversed when actual information is received from third parties and the Partnership's internal records have been reconciled.

Incentive Compensation Plans

The Partnership issues phantom units under certain share-based compensation plans as described further in Note 21. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit. The majority of phantom units are treated as equity awards, and compensation expense is measured for these phantom unit grants based on the fair value of the units on the grant date, as defined by GAAP. The fair value of the units awarded is amortized into earnings, reduced for an estimate of expected forfeitures, over the period of service corresponding with the vesting period. For certain plans, the awards are accounted for as liability awards and the compensation expense is adjusted monthly for the change in the fair value of the unvested units granted.

To satisfy common unit awards, the Partnership may issue new common units, acquire common units in the open market, or use common units already owned by the general partner.

Income Taxes

The Partnership is not a taxable entity for federal income tax purposes. As such, the Partnership does not directly pay federal income tax. The Partnership's taxable income or loss, which may vary substantially from the net income or loss reported in the Consolidated Statements of Operations, is includable in the federal income tax returns of each partner. The Partnership is, however, a taxable

2. Summary of Significant Accounting Policies (Continued)

entity under certain state jurisdictions. The Corporation is a tax paying entity for both federal and state purposes.

The Partnership and the Corporation account for income taxes under the asset and liability method. Deferred income taxes are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis, capital loss carryforwards and net operating loss and credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates applied to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of any tax rate change on deferred taxes is recognized in the period that includes the enactment date of the tax rate change. Realizability of deferred tax assets is assessed and, if not more likely than not, a valuation allowance is recorded to reflect the deferred tax assets at net realizable value as determined by management. Deferred tax balances that are expected to be settled within twelve months are classified as current, and all other deferred tax balance are classified as long term in the accompanying Consolidated Balance Sheets.

The Corporation recognizes a tax expense or a tax benefit on its proportionate share of Partnership income or loss resulting from the Corporation's ownership of Class A units of the Partnership even though for financial reporting purposes said income or loss is eliminated in consolidation. The deferred income tax component relates to the change in the book to tax basis difference in the carrying amount of the investment in the Partnership which results primarily from its timing differences in the Corporation's proportionate share of the book income or loss as compared with the Corporation's proportionate share of the taxable income or loss of the Partnership.

To account for uncertainty in income taxes recognized in financial statements, the Partnership prescribes a "more likely than not" recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The Partnership records penalties and interest related to income taxes as a component of income before tax, if applicable. Penalties are recorded in *Miscellaneous income (expense), net* and interest is recorded in *Interest expense* in the accompanying Consolidated Statements of Operations.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income and other comprehensive income (loss), which includes unrealized gains and losses on marketable securities that are classified as available for sale.

Earnings (Loss) Per Unit

The Partnership's outstanding phantom units are considered to be participating securities, and therefore basic and diluted earnings per common unit are calculated pursuant to the two-class method described in the generally accepted accounting principles for earnings per share. In accordance with the two-class method, basic earnings per common unit is calculated by dividing net income attributable to the Partnership, after deducting amounts that are allocable to the outstanding phantom units, by the weighted-average number of common units outstanding during the period. The amount allocable to the phantom units is generally calculated as if all of the net income attributable to the Partnership were distributed, and not on the basis of actual cash distributions for the period. However, during periods in which a net loss attributable to the Partnership is reported or periods in which the total distributions exceed the reported net income attributable to the Partnership, the amount allocable to the phantom

2. Summary of Significant Accounting Policies (Continued)

units is based on actual distributions to the phantom unit holders. Diluted earnings per unit is calculated by dividing net income attributable to the Partnership, after deducting amounts allocable to the outstanding phantom units, by the weighted-average number of potential common units outstanding during the period. Potential common units are excluded from the calculation of diluted earnings per unit during periods in which net income attributable to the Partnership, after deducting amounts that are allocable to the outstanding phantom units, is a loss as the impact would be anti-dilutive.

Business Combinations

Transactions in which the Partnership acquires control of a business are accounted for under the acquisition method. The identifiable assets, liabilities and any non-controlling interests are recorded at the estimated fair market values as of the acquisition date. The purchase price in excess of the fair value acquired is recorded as goodwill.

Accounting for Changes in Ownership Interests in Subsidiaries

The Partnership's ownership interest in a consolidated subsidiary may change if it sells a portion of its interest, or if the subsidiary issues or re-purchases its own shares. If the transaction does not result in a change in control over the subsidiary and it is not deemed to be a sale of real estate, the transaction is accounted for as an equity transaction. If the transaction results in a change in control it would result in the deconsolidation of a subsidiary with a gain or loss recognized in the statement of operations. During 2009 the Partnership's ownership interest in MarkWest Liberty Midstream changed in two separate transactions which were accounted for as equity transactions. See Note 4 for a description of the transactions and the impact to the financial statements.

Recent Accounting Pronouncements

In June 2009, the FASB amended the Variable Interest Entity ("VIE") subsections of the consolidation guidance. The amended guidance changes the criteria for determining if a VIE exists and whether or not a VIE should be consolidated. The amended guidance was effective for the Partnership on January 1, 2010, and the Partnership reconsidered its previous VIE conclusions and financial statement disclosures. The amendment had no effect on the Partnership's consolidated financial statements.

In September 2009, the FASB amended the accounting guidance for revenue recognition for multiple-deliverable arrangements. The amended guidance establishes a hierarchy for determining the selling price of each individual deliverable and eliminates the residual value method of allocating the selling price. The amended guidance is effective for the Partnership prospectively for all revenue arrangements entered into or materially modified on or after January 1, 2011. The amendment will not have a material effect on the Partnership's consolidated financial statements.

In January 2010, the FASB issued a clarification to the accounting for decreases in ownership interests in certain subsidiaries. The FASB clarified that the guidance for consolidations does not apply to transactions involving in-substance real estate or the conveyances of oil and gas mineral rights. The FASB indicated that the established guidance for transactions involving in-substance real estate or oil and gas mineral rights should be followed. The clarification also expands disclosures required upon the deconsolidation of a subsidiary. The guidance within this clarification was effective for the Partnership as of December 31, 2009, with retrospective application required to January 1, 2009. The Partnership

2. Summary of Significant Accounting Policies (Continued)

determined that its sale of equity interests in MarkWest Pioneer qualifies as a sale of in-substance real estate; however, the impact on the Partnership's consolidated financial statements was not material.

In February 2010, the FASB amended the embedded derivative and hedging guidance. The amended guidance modified the requirements for determining whether an embedded derivative is clearly and closely related to the host contract. The amended embedded derivative guidance was effective for the Partnership on January 1, 2010. The amended guidance had no effect on the Partnership's consolidated financial statements.

In March 2010, the FASB amended a scope exception for embedded credit derivatives in the derivatives and hedging guidance. The amended guidance clarified which types of embedded credit derivative features are required to be analyzed for potential bifurcation. The amended guidance was effective for the Partnership on July 1, 2010. The amended guidance had no effect on the Partnership's consolidated financial statements.

3. Redemption and Merger

On February 21, 2008, the Partnership completed the transactions contemplated by its plan of redemption and merger with the Corporation and MWEP, L.L.C., a wholly-owned subsidiary of the Partnership. Under the Merger, the shareholders of the Corporation exchanged each share of Corporation common stock for consideration equal to 1.9051 Partnership common units ("Exchange Ratio"). This Exchange Ratio was computed based on the stated consideration of 1.285 Partnership common units plus $20 in cash, or equivalent value. Contemporaneously with the closing of the transactions contemplated by the Merger, the Partnership separately acquired 100% of the Class B membership interests in the General Partner that had been held by current and former management and certain directors of the Corporation and the General Partner under the Participation Plan in exchange for approximately $21.5 million in cash and approximately 0.9 million common units valued at $30.1 million. Using the Exchange Ratio, the number of Corporation shares outstanding as of December 31, 2007 and activity through February 21, 2008 has been adjusted to the equivalent number of Partnership common units in the accompanying Consolidated Financial Statements. The following table illustrates these conversions (shares and units in thousands):

	Common Shares	Exchange Ratio	Common Units
Shares of Corporation Common Stock Outstanding at December 31, 2007	11,999.8	1.9051	22,861
Stock Option exercises in first quarter 2008, prior to Merger	51.5	1.9051	98
Conversion of Restricted Shares to Partnership Phantom units	(23.8)	1.9051	(45)
Shares eligible for redemption or conversion to Partnership Units	12,027.5		22,914
Common shares tendered for redemption in cash	(3,914.5)	1.9051	(7,458)
Common shares tendered for conversion to Partnership common units	8,113.0	1.9051	15,456

In connection with the Merger, the incentive distribution rights in the Partnership, the 2% economic interest in the Partnership held by MarkWest Energy GP, L.L.C. (the "General Partner") and the Partnership common units owned by the Corporation were exchanged for Partnership Class A units. Class A units represent limited partner interests in the Partnership and have identical rights and

3. Redemption and Merger (Continued)

obligations of the Partnership common units except that Class A units (a) do not have the right to vote on, approve or disapprove, or otherwise consent to or not consent to any matter (including mergers, share exchanges and similar statutory authorizations) except as otherwise required by any non-waivable provision of law and (b) do not share in any cash and cash equivalents on hand, income, gains, losses, deductions and credits that are derived from or attributable to the Partnership's ownership of, or sale or disposition of, the shares of MarkWest Hydrocarbon common stock. The Class A units held by the Corporation and the General Partner are not treated as outstanding common units in the Consolidated Balance Sheets.

4. Variable Interest Entities

MarkWest Liberty Midstream

On February 27, 2009, the Partnership entered into a joint venture with M&R MWE Liberty LLC ("M&R"), an affiliate of The Energy & Minerals Group and its affiliated funds, which is a private equity firm focused on investments in selected areas of the energy infrastructure and natural resources sectors. The joint venture entity, MarkWest Liberty Midstream, operates in the natural gas midstream business in and around the Marcellus Shale in western Pennsylvania and northern West Virginia. The Partnership contributed its existing Marcellus Shale natural gas gathering and processing assets to MarkWest Liberty Midstream in exchange for a 60% ownership interest. The agreed-to value of the contributed assets was approximately $107.5 million. At closing, M&R contributed cash of $50.0 million in exchange for a 40% ownership interest. A wholly-owned subsidiary of the Partnership serves as the operator of MarkWest Liberty Midstream and provides field operating and general and administrative services. A portion of the fee for providing these services is fixed.

Effective November 1, 2009, the Partnership and M&R executed the Amended Liberty Agreement pursuant to which M&R increased its participation in MarkWest Liberty Midstream. The Partnership and M&R agreed to maintain a 60%/40% respective ownership interest in MarkWest Liberty Midstream until January 1, 2011, at which time M&R's ownership interest will increase from 40% to 49%. The Partnership and M&R agreed to jointly fund the capital requirements of MarkWest Liberty Midstream at agreed upon levels until the Partnership's contributed capital is proportionate to its eventual 51% ownership interest (the "Equalization Date"), which is required to occur on or before December 31, 2012. The Partnership is required to reinvest all cash distributions from MarkWest Liberty Midstream until the Equalization Date has occurred. If the Equalization Date has not occurred by the end of 2012, M&R may require the Partnership to contribute the amount of the shortfall at December 31, 2012, or may allow the Partnership to continue to fund 100% of MarkWest Liberty Midstream's capital expenditures until its total contributed capital is proportionate to its ownership interest. Following the Equalization Date, M&R will have pre-emptive rights to maintain its ownership interest in MarkWest Liberty Midstream in a range of between 45% and 49% or have its ownership interest diluted to the extent that it elects not to fund its proportionate share.

During 2009, M&R and the Partnership contributed an additional $150.0 million and $8.0 million, respectively, to fund the capital expenditures of MarkWest Liberty Midstream. During 2010, M&R and the Partnership contributed $158.3 million and $171.1 million, respectively, to the entity. As of December 31, 2010, the capital contributed to MarkWest Liberty Midstream is disproportionate to each member's respective ownership interest. The cumulative capital contributed by M&R exceeded its ownership interest by $120.2 million as of December 31, 2010. Under the terms of the joint venture

4. Variable Interest Entities (Continued)

agreement, M&R received a special $11.4 million and $3.4 million non-cash allocation of net income from MarkWest Liberty Midstream during the years ended December 31, 2010 and 2009, respectively, due to its excess contributions. The non-cash allocation is recorded in *Net income attributable to non-controlling interest*.

The Partnership has determined that MarkWest Liberty Midstream is a VIE primarily due to the Partnership's disproportionate economic interests as compared to its voting interests in the entity. The Partnership has made capital contributions that differ from its stated ownership interests. Additionally, MarkWest Liberty Midstream has insufficient equity at risk, as evidenced by the additional capital funding requirements discussed above.

Although voting interests are shared equally between the respective members of MarkWest Liberty Midstream, the Partnership has concluded that it is the primary beneficiary based on its affiliate's role as the operator. The Partnership believes that its role as the operator along with its equity interests give it the power to direct the activities that most significantly affect the economic performance of MarkWest Liberty Midstream.

As a result of the execution of the Amended Liberty Agreement, the Partnership reconsidered the accounting treatment for MarkWest Liberty Midstream as a VIE and determined that the conclusions as discussed above remain unchanged.

MarkWest Pioneer

MarkWest Pioneer is the owner and operator of the Arkoma Connector Pipeline, a 50-mile FERC-regulated pipeline that was placed in service in mid-July 2009. The Arkoma Connector Pipeline is designed to provide approximately 638,000 Dth/d of Arkoma Basin takeaway capacity and interconnects with the Midcontinent Express Pipeline and the Gulf Crossing Pipeline. A wholly-owned subsidiary of the Partnership serves as the operator and provides field operating and general and administrative services for fixed fees.

On May 1, 2009, the Partnership entered into a joint venture with Arkoma Pipeline Partners, LLC ("ArcLight"), an affiliate of ArcLight Capital Partners, LLC which is an investment firm focused on opportunities throughout the energy industry. ArcLight acquired a 50% equity interest in MarkWest Pioneer for a total purchase price of $62.5 million. The Partnership retained a 50% equity interest and was obligated to fund all capital expenditures necessary to complete construction of the Arkoma Connector Pipeline in excess of $125.0 million (the "Excess Capital Expenditures"). As a result of the Excess Capital Expenditures, the Partnership recorded a $10.3 million equity loss, net of a $1.5 million tax benefit, that is reflected as a transfer to non-controlling interest, and the Partnership's recorded ownership interest as of December 31, 2010 exceeds its stated ownership interest in MarkWest Pioneer by approximately $1.8 million. The difference between the carrying value of the Partnership's ownership interest and its stated ownership interest is amortized based upon the respective useful lives of the assets to which the difference relates.

The Partnership has determined that MarkWest Pioneer is a VIE primarily due to the Partnership's disproportionate economic interests as compared to its voting interests in each entity. Due to the funding of the Excess Capital Expenditures, the Partnership has made capital contributions to MarkWest Pioneer that differ from its stated ownership interests. Although voting interests are shared equally between the respective members of MarkWest Pioneer, the Partnership has concluded that it is

4. Variable Interest Entities (Continued)

the primary beneficiary based on its affiliate's role as the operator. The Partnership believes that its role as the operator along with its equity interests give it the power to direct the activities that most significantly affect the economic performance of MarkWest Pioneer.

Financial Statement Impact of VIEs

As the primary beneficiary of MarkWest Liberty Midstream and MarkWest Pioneer, the Partnership consolidates the entities and recognizes non-controlling interests. The following tables show the assets and liabilities attributable to VIEs reflected in the Partnership's Consolidated Balance Sheets as of December 31, 2010 and 2009 (in thousands):

	As of December 31, 2010		
	MarkWest Liberty Midstream	MarkWest Pioneer	Total
ASSETS			
Cash and cash equivalents	$ —	$ 2,913	$ 2,913
Receivables, net	42,181	1,602	43,783
Inventories	8,431	—	8,431
Other current assets	271	1	272
Property, plant and equipment, net of accumulated depreciation of $28,869 and $9,300, respectively	664,778	147,039	811,817
Restricted cash	28,001	—	28,001
Other long-term assets	281	102	383
Total assets	$743,943	$151,657	$895,600
LIABILITIES			
Accounts payable	$ 5,945	$ —	$ 5,945
Accrued liabilities	63,450	1,263	64,713
Other long-term liabilities	86	68	154
Total liabilities	$ 69,481	$ 1,331	$ 70,812

4. Variable Interest Entities (Continued)

	As of December 31, 2009		
	MarkWest Liberty Midstream	MarkWest Pioneer	Total
ASSETS			
Cash and cash equivalents	$ 18,168	$ 3,774	$ 21,942
Receivables, net	20,753	1,280	22,033
Inventories	3,343	—	3,343
Other current assets	225	102	327
Property, plant and equipment, net of accumulated depreciation of $8,273 and $3,051, respectively	330,116	153,478	483,594
Other long-term assets	314	—	314
Total assets	$372,919	$158,634	$531,553
LIABILITIES			
Accounts payable	$ 2,713	$ 32	$ 2,745
Accrued liabilities	43,136	1,479	44,615
Other long-term liabilities	80	285	365
Total liabilities	$ 45,929	$ 1,796	$ 47,725

The assets of MarkWest Liberty Midstream and MarkWest Pioneer are the property of the respective entities and are not available to the Partnership for any other purpose, including collateral for its secured debt (see Note 17 and Note 26). VIE asset balances can only be used to settle obligations of each respective VIE. The liabilities of MarkWest Liberty Midstream and MarkWest Pioneer do not represent additional claims against the Partnership's general assets and the creditors or beneficial interest holders of the VIE do not have recourse to the general credit of the Partnership. The Partnership's Liberty segment includes the results of operations of MarkWest Liberty Midstream (see Note 25). The Partnership's Southwest segment includes the results of operations of MarkWest Pioneer (see Note 25). The cash flow information for MarkWest Liberty Midstream and MarkWest Pioneer comprise substantially all of the cash flow information of the Partnership's non-guarantor subsidiaries (see Note 26). The Partnership's maximum exposure to loss as a result of its involvement with the VIEs includes its equity investment, any additional capital contribution commitments and any operating expense incurred by the subsidiary operator in excess of its subsidiary's compensation for the performance of those services. The Partnership did not provide any financial support to the VIEs that it was not contractually obligated to provide during the years ended December 31, 2010 and 2009.

4. Variable Interest Entities (Continued)

The following table shows the net income (loss) attributable to the Partnership and transfers to the non-controlling interests for the years ended December 31, 2010 and 2009 (in thousands).

	Year ended December 31, 2010	Year ended December 31, 2009
Net income (loss) attributable to the Partnership	$467	$(118,668)
Transfers to the non-controlling interests:		
Decrease in Partners' Capital for transaction costs related to sale of equity interest in MarkWest Liberty Midstream and MarkWest Pioneer	—	(7,310)
Decrease in Partners' Capital for transfer to non-controlling interest from sale of equity interest in MarkWest Pioneer(1)	—	(10,288)
Net income (loss) attributable to the Partnership and transfers to the non-controlling interest	$467	$(136,266)

(1) Decrease in Partners' Capital for transfer to non-controlling interest is determined based on the amount of Excess Capital Expenditures as estimated on the closing date. As of December 31, 2009, the decrease is shown net of tax benefit.

5. Divestitures

SMR Transaction

On September 1, 2009, the Partnership completed the sale of the steam methane reformer ("SMR Transaction") the Partnership began constructing at its Javelina gas processing and fractionation facility in Corpus Christi, Texas. Under the terms of the agreement, the Partnership received proceeds of $73.1 million and the purchaser completed the construction of the SMR. The Partnership and the purchaser also executed a related product supply agreement under which the Partnership will receive all of the product produced by the SMR through 2030 in exchange for processing fees and the reimbursement of certain other expenses. The processing fee payments began when the SMR commenced operations in March 2010. The Partnership is deemed to have continuing involvement with the SMR as a result of certain provisions in the related agreements. Therefore, the transaction is treated as a financing arrangement under GAAP. The Partnership has continued to report an asset, and the related depreciation, for the total capitalized costs of constructing the SMR and has recorded a liability equal to the proceeds from the transaction plus the estimated costs incurred by the buyer to complete construction ("SMR Liability"). The Partnership will impute interest on the SMR Liability at 9.35% annually, its incremental borrowing rate at the time of the transaction. The accrued interest on the SMR Liability was capitalized until the SMR commenced operations and the Partnership began payment of the processing fee under the product supply agreement. Each processing fee payment has multiple elements: reduction of principal of the SMR Liability, interest expense associated with the SMR Liability, and facility expense related to the operation of the SMR. As of December 31, 2010 and

5. Divestitures (Continued)

2009, the following amounts related to the SMR are included in the accompanying Consolidated Balance Sheets (in thousands):

	December 31, 2010	December 31, 2009
ASSETS		
Property, plant and equipment, net of accumulated depreciation of $4,390 and $0, respectively	$100,973	$103,522
LIABILITIES		
Accrued liabilities	$ 1,875	$ 1,434
Other long-term liabilities	93,909	93,776

Other Divestitures

Effective November 1, 2009, the Partnership sold its interest in Basin Pipeline, LLC ("Basin") for nominal consideration. Basin owned a natural gas pipeline in Manistee, Mason and Oceana Counties in Michigan. The Partnership ceased its operations in western Michigan, including Basin, in July 2009. The Partnership's loss on the disposal of Basin was near zero as an impairment expense related to Basin was recorded in 2008. See Note 13 for further discussion of the impairment.

Effective December 31, 2009, the Partnership sold its 50% equity interest in Starfish Pipeline Company, LLC ("Starfish") to Enbridge Offshore (Gas Transmission), L.L.C. for a purchase price of $25.0 million. The Partnership recorded a $6.8 million gain on the sale of its equity interest in Starfish. The calculated gain on sale was impacted by the impairment of $41.4 million recorded in 2008 (see Note 14).

6. Derivative Financial Instruments

Commodity Contracts

NGL and natural gas prices are volatile and are impacted by changes in fundamental supply and demand, as well as market uncertainty, availability of NGL transportation and fractionation capacity and a variety of additional factors that are beyond the Partnership's control. The Partnership's profitability is directly affected by prevailing commodity prices primarily as a result of processing or conditioning at its processing plants or third-party processing plants, purchasing and selling or gathering and transporting volumes of natural gas at index-related prices and the cost of third-party transportation and fractionation services. To the extent that commodity prices influence the level of drilling activity, such prices also affect profitability. To protect itself financially against adverse price movements and to maintain more stable and predictable cash flows so that the Partnership can meet its cash distribution objectives, debt service and capital expenditures, the Partnership executes a hedging strategy governed by the risk management policy approved by the General Partner's board of directors (the "Board"). The Partnership has a committee comprised of senior management that oversees risk management activities, continually monitors the risk management program and adjusts its strategy as conditions warrant. The Partnership enters into certain derivative contracts to reduce the risks associated with unfavorable changes in the prices of natural gas, NGLs and crude oil. Derivative

6. Derivative Financial Instruments (Continued)

contracts utilized are swaps, options and fixed price forward contracts traded on the OTC market. The risk management policy does not allow for speculative derivative contracts.

To mitigate its cash flow exposure to fluctuations in the price of NGLs, the Partnership has entered into derivative financial instruments relating to the future price of NGLs and crude oil. Generally the Partnership hedges its NGL price risk using crude oil as NGL financial markets lack adequate liquidity and historically there has been a strong relationship between changes in NGL and crude oil prices. The pricing relationship between NGLs and crude oil may vary in certain periods due to various market conditions. In periods where NGL prices and crude oil prices are not consistent with the historical relationship, the Partnership incurs increased risk and additional gains or losses. The Partnership enters into NGL derivative contracts when adequate market liquidity exists.

To mitigate its cash flow exposure to fluctuations in the price of natural gas, the Partnership primarily utilizes derivative financial instruments relating to the future price of natural gas and takes into account the partial offset of its long and short gas positions resulting from normal operating activities.

As a result of its current derivative positions, the Partnership has mitigated a portion of its expected commodity price risk through the fourth quarter of 2013. For entities that are not wholly owned by the Partnership, commodity risk is mitigated only for the Partnership's ownership interest. The Partnership would be exposed to additional commodity risk in certain situations such as if producers under deliver or over deliver product or when processing facilities are operated in different recovery modes. In the event the Partnership has derivative positions in excess of the product delivered or expected to be delivered, the excess derivative positions may be terminated.

The Partnership enters into derivative contracts primarily with financial institutions that are participating members of the amended and restated credit agreement as collateral is not posted by the Partnership as the participating members have a collateral position in substantially all the wholly-owned assets of the Partnership. All of the Partnership's financial derivative positions are currently with participating bank group members. Management conducts a standard credit review on counterparties and the Partnership has agreements containing collateral requirements. For all participating bank group members, collateral requirements do not exist when a derivative contract favors the Partnership. The Partnership uses standardized agreements that allow for offset of positive and negative exposures (master netting arrangements).

The Partnership records derivative contracts at fair value in the Consolidated Balance Sheets and has not elected hedge accounting or the normal purchases and normal sales designation which may cause volatility in the Statement of Operations as the Partnership recognizes in current earnings all unrealized gains and losses from the mark to market on derivative activity.

Embedded Derivative in Debt Contract

On May 26, 2009, the Partnership completed the private placement of senior notes with two contingent written put options as described in Note 17. The written put options were considered embedded derivatives and were not considered clearly and closely related to the indenture governing the notes. When a hybrid contract contains more than one embedded derivative requiring separate accounting, the embedded derivatives must be aggregated and accounted for as one compound embedded derivative. As of December 31, 2009, the fair value of the compound embedded derivative in

6. Derivative Financial Instruments (Continued)

the indenture was recorded as a component of *Long-term debt* in the Consolidated Balance Sheets. These senior notes were redeemed in the fourth quarter of 2010 and the put options no longer exist as of December 31, 2010.

Interest Rate Contracts

The Partnership borrows funds using a combination of fixed and variable rate debt. The Partnership may utilize interest rate swap contracts to manage the interest rate risk associated with the fair value of its fixed rate borrowings and to effectively convert a portion of the underlying cash flows related to its long-term fixed rate debt securities into variable rate cash flows in order to achieve its desired mix of fixed and variable rate debt. As a result, the Partnership's future cash flows from these agreements will vary with the market rate of interest.

During the first quarter of 2010, the Partnership terminated all of its outstanding interest rate swap contracts. The financial statement impact is disclosed in the tables below.

Financial Statement Impact of Derivative Contracts

See Note 2 for a description of how the Partnership values its derivative financial instruments and how the instruments impact its financial statements. The impact of the Partnership's derivative

6. Derivative Financial Instruments (Continued)

instruments on its Consolidated Balance Sheets and Statements of Operations are summarized below (in thousands):

Derivative contracts not designated as hedging instruments and their balance sheet location	Assets		Liabilities	
	Fair Value at December 31, 2010	Fair Value at December 31, 2009	Fair Value at December 31, 2010	Fair Value at December 31, 2009
Commodity contracts(1)				
Fair value of derivative instruments—current	$4,345	$ 8,312	$ (65,489)	$ (60,464)
Fair value of derivative instruments—long-term	417	15,810	(66,290)	(62,519)
Interest rate contracts				
Fair value of derivative instruments—current	—	509	—	—
Embedded derivative in debt contract				
Long-term debt	—	—	—	(190)
Total	$4,762	$24,631	$(131,779)	$(123,173)

(1) Includes *Embedded Derivatives in Commodity Contracts* as discussed below.

Derivative contracts not designated as hedging instruments and the location of gain or (loss) recognized in income	Year ended December 31,		
	2010	2009	2008
Revenue: Derivative (loss) gain			
Realized (loss) gain	$(33,560)	$ 87,289	$ (15,704)
Unrealized (loss) gain	(20,372)	(207,641)	293,532
Total revenue: derivative (loss) gain	(53,932)	(120,352)	277,828
Derivative loss related to purchased product costs			
Realized (loss) gain	(21,909)	(53,052)	7,368
Unrealized loss	(5,804)	(15,831)	(29,739)
Total derivative loss related to purchase product costs	(27,713)	(68,883)	(22,371)
Derivative gain (loss) related to facility expenses			
Unrealized gain (loss)	1,295	373	(644)
Derivative gain related to interest expense			
Realized gain	2,380	2,000	—
Unrealized (loss) gain	(509)	509	—
Total derivative gain related to interest expense	1,871	2,509	—
Miscellaneous income (expense), net			
Unrealized gain	190	336	—
Total (loss) gain	$(78,289)	$(186,017)	$254,813

6. Derivative Financial Instruments (Continued)

At December 31, 2010 and 2009, the fair value of the Partnership's commodity derivative contracts is inclusive of premium payments of $4.4 million and $7.7 million, net of amortization, respectively. For 2010, 2009 and 2008, the *Realized (loss) gain—revenue* includes amortization of premium payments of $3.3 million, $5.7 million and $2.1 million, respectively.

During the first quarter of 2009, the Partnership settled a portion of its derivative positions covering 2009, 2010, and 2011 for $15.2 million of net realized gains. The settlement was completed prior to the contractual settlement to improve liquidity and to mitigate credit risk with certain counterparties, and as such does not represent trading activity. The settlement was recorded as $26.5 million of realized gains in *Realized (loss) gain—revenue* and $11.3 million loss is included in *Derivative loss related to purchased product costs* in the accompanying Consolidated Statements of Operations.

Credit Risk Contingent Feature

At December 31, 2009, the Partnership had a contractual arrangement with one non-bank group counterparty that contained a credit risk contingent feature related to margin requirements. On July 29, 2010, the Partnership executed a joinder agreement to include the counterparty in the bank group. As a result, all of the Partnership's financial derivative positions are currently with participating bank group members, and the credit risk contingent feature related to margin requirements no longer exists.

Volume of Derivative Activity

As of December 31, 2010, the Partnership had the following outstanding commodity contracts that were entered into to economically hedge future sales of NGLs or future purchases of natural gas.

Derivative contracts not designated as hedging instruments	Notional Quantity (net)
Crude Oil (bbl)	8,351,160
Natural Gas (MMBtu)	14,757,845

Embedded Derivatives in Commodity Contracts

The Partnership has a commodity contract with a producer in the Appalachia region which creates a floor on the frac spread for gas purchases of 9,000 Dth/d. The primary term of the commodity contract, a component of a broader regional arrangement, expired on December 31, 2009 but the producer exercised its right to extend the processing agreement and the commodity contract through the first quarter of 2015. The fair value of the commodity contract is marked based on an index price through *Derivative loss related to purchased product costs*. As of December 31, 2010 and 2009, the estimated fair value of this contract was a liability of $36.0 million and $33.9 million, respectively. This contract was amended after December 31, 2010 (see Note 30).

The Partnership has a commodity contract which gives it an option to fix a component of the utilities cost to an index price on electricity at one of its plant locations through the fourth quarter of 2014. The value of the derivative component of this contract is marked to market through *Derivative (gain) loss related to facility expenses*. As of December 31, 2010 and 2009, the estimated fair value of this contract was an asset of $1.0 million and a liability of $0.3 million, respectively.

7. Fair Value

Fair Value Measurement

Fair value measurements and disclosures relate primarily to the Partnership's derivative positions discussed in Note 6. See Note 2 for a description of the guidance and the fair value hierarchy.

The derivative contracts are measured at fair value on a recurring basis and classified within Level 2 and Level 3 of the valuation hierarchy. The Level 2 and Level 3 measurements are obtained using a market approach. LIBOR rates are an observable input for the measurement of all derivative contracts. The measurements for all commodity contracts contain observable inputs in the form of forward prices based on WTI crude oil prices; Columbia Appalachia, Henry Hub and Houston Ship Channel natural gas prices; Mont Belvieu and Conway NGL prices; and ERCOT electricity prices. Level 2 instruments include crude oil and natural gas swap contracts; the valuations are based on the appropriate commodity prices and contain no significant unobservable inputs. Level 3 instruments include crude oil options, all NGL transactions, embedded derivatives in commodity contracts and the embedded put options. The significant unobservable inputs for crude oil options, NGL transactions and embedded derivatives in commodity contracts include option volatilities and commodity prices interpolated and extrapolated due to inactive markets. The significant unobservable inputs for the embedded put options are option volatilities and management's assumptions about the probability of specific events occurring in the future.

The following table presents the financial instruments carried at fair value as of December 31, 2010 and 2009, and by the valuation hierarchy (as described above, in thousands):

As of December 31, 2010	Assets	Liabilities
Significant other observable inputs (Level 2)		
Commodity contracts	$ 52	$ (77,776)
Significant unobservable inputs (Level 3)		
Commodity contracts	3,674	(18,031)
Embedded derivatives in commodity contracts	1,036	(35,972)
Total carrying value in Consolidated Balance Sheet	$4,762	$(131,779)

As of December 31, 2009	Assets	Liabilities
Significant other observable inputs (Level 2)		
Commodity derivative contracts	$ 9,920	$ (63,242)
Significant unobservable inputs (Level 3)		
Commodity derivative contracts	14,202	(25,542)
Embedded derivatives in commodity contracts	—	(34,199)
Interest rate contracts	509	—
Embedded derivative in debt contracts	—	(190)
Total carrying value in Consolidated Balance Sheet	$24,631	$(123,173)

7. Fair Value (Continued)

Changes in Level 3 Fair Value Measurements

The tables below include a rollforward of the balance sheet amounts for the year ended December 31, 2010 and 2009 (including the change in fair value) for assets and liabilities classified by the Partnership within Level 3 of the valuation hierarchy (in thousands).

	Year Ended December 31, 2010			
	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)	Interest Rate Contracts	Embedded Derivative in Debt Contract
Fair value at beginning of period	$(11,340)	$(34,199)	$ 509	$(190)
Total gain or loss (realized and unrealized) included in earnings(1)	(11,093)	(11,792)	1,871	190
Purchases, sales, issuances and settlements (net)	8,076	11,055	(2,380)	—
Fair Value at End of Period	$(14,357)	$(34,936)	$ —	$ —
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at December 31(1)	$(13,101)	$ (9,329)	$ —	$ —

	Year Ended December 31, 2009				
	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)	Interest Rate Contracts	Embedded Derivative in Debt Contract	Trading Securities
Fair value at beginning of period	$ 72,478	$ (22)	$ —	$ —	$ 512
Total gain or loss (realized and unrealized) included in earnings(1)	(51,833)	(39,549)	2,509	336	40
Purchases, sales, issuances and settlements (net)	(31,985)	5,372	(2,000)	(526)	(552)
Fair Value at End of Period	$(11,340)	$(34,199)	$ 509	$(190)	$ —
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at December 31(1)	$(35,616)	$(34,177)	$ 509	$ 336	$ —

(1) Gains and losses on Commodity Derivative Contracts classified as Level 3 are recorded in *Derivative (loss) gain related to revenue*. Gains and losses on Embedded Derivatives in Commodity Contracts are recorded in *Purchased product costs, Derivative loss related to purchased product costs*

7. Fair Value (Continued)

and *Derivative (gain) loss related to facility expenses*. Gains on Embedded Derivative in Debt Contract are recorded in *Miscellaneous income (expense), net*. Gains and losses on Interest Rate Contracts are recorded in *Derivative gain related to interest expense*.

Assets and liabilities measured at fair value on a nonrecurring basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis; that is, the instruments are not measured at fair value on an ongoing basis but are subject to fair value adjustments in certain circumstances. As of June 30, 2009, certain long-lived assets of Wirth Gathering, a consolidated subsidiary, were required to be measured at fair value in conjunction with the Partnership's impairment evaluation for long-lived assets. Property, plant and equipment and intangible assets with a net book value of $5.2 million and $0.7 million, respectively, were written down to an estimated fair value of zero, resulting in an impairment charge of $5.9 million. The Partnership estimated the fair value of these assets based on an income approach using significant unobservable inputs (Level 3). See Note 13 for further discussion of the impairment. As of December 31, 2010, there were no other assets or liabilities to be measured at fair value on a nonrecurring basis.

8. Significant Customers and Concentration of Credit Risk

For the years ended December 31, 2010, 2009 and 2008, revenues from one customer totaled $198.6 million, $134.8 million and $234.0 million, representing 16.0%, 15.7% and 22.1% of *Revenue*, respectively. Sales to this customer are made primarily from the Southwest segment. As of December 31, 2010 and 2009, the Partnership had $5.1 million and $5.2 million of accounts receivable from this customer, respectively.

9. Receivables

Receivables consist of the following (in thousands):

	December 31, 2010	December 31, 2009
Trade, net	$174,216	$129,511
Other(1)	4,993	11,458
Total receivables	$179,209	$140,969

(1) The 2009 balance relates primarily to amounts due from the settlement of derivative positions and imbalances.

10. Inventories

Inventories consist of the following (in thousands):

	December 31, 2010	December 31, 2009
Natural gas and natural gas liquids	$15,930	$20,939
Spare parts	7,502	8,136
Total inventories	$23,432	$29,075

11. Property, Plant and Equipment

Property, plant and equipment consist of the following (in thousands):

	December 31, 2010	December 31, 2009
Natural gas gathering and NGL transportation pipelines and facilities	$1,625,170	$1,327,751
Processing plants	584,886	407,352
Fractionation and storage facilities	81,317	67,839
Crude oil pipelines	16,810	16,810
Land, building, office equipment and other	155,437	131,735
Construction in progress	149,407	203,157
Property, plant and equipment	2,613,027	2,154,644
Less: accumulated depreciation	(294,003)	(173,000)
Total property, plant and equipment, net	$2,319,024	$1,981,644

12. Goodwill and Intangible Assets

Goodwill. All goodwill was acquired in 2008 as a result of the Merger and the acquisition of PQ Assets. There was no activity related to goodwill during 2009 or 2010. The table below shows the gross amount of goodwill acquired and the cumulative impairment loss recognized as of December 31, 2010 (in thousands).

	Southwest	Northeast	Gulf Coast	Total
Goodwill acquired	$ 24,324	$3,948	$ 9,854	$ 38,126
Cumulative impairment	(18,851)	—	(9,854)	(28,705)
Ending balance	$ 5,473	$3,948	$ —	$ 9,421

Intangible Assets. The Partnership's intangible assets as of December 31, 2010 and 2009 are comprised of customer contracts and relationships, as follows (in thousands):

	December 31, 2010			December 31, 2009			
Description	Gross	Accumulated Amortization	Net	Gross	Accumulated Amortization	Net	Useful Life
Southwest	$406,801	$ (69,655)	$337,146	$406,801	$(47,147)	$359,654	10 - 20 yrs
Northeast	68,573	(19,590)	48,983	68,573	(12,733)	55,840	10 yrs
Gulf Coast	262,772	(35,323)	227,449	262,772	(23,855)	238,917	20 - 25 yrs
Total:	$738,146	$(124,568)	$613,578	$738,146	$(83,735)	$654,411	

12. Goodwill and Intangible Assets (Continued)

Estimated future amortization expense related to the intangible assets at December 31, 2010, is as follows (in thousands):

Year ending December 31,	
2011	$ 40,769
2012	40,769
2013	40,769
2014	40,769
2015	40,769
Thereafter	409,733
	$613,578

13. Impairment of Goodwill and Long-Lived Assets

Goodwill. The Partnership's policy is to evaluate goodwill for impairment annually as of November 30, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. The evaluation performed as of November 30, 2010 did not indicate any impairment of goodwill.

Due to the significant decline in the market prices of crude oil and other NGLs and the continued decline in the trading price of the Partnership's common units at the end of 2008, goodwill was evaluated for impairment in 2008. As a result, the Partnership recorded impairment charges of $28.7 million to write-off the goodwill balance allocable to four of the Partnership's reporting units. Approximately $18.8 million and $9.9 million of the goodwill impairment related to the Southwest and Gulf Coast segments, respectively. The remaining goodwill balance of $9.4 million consists of $5.5 million allocated to the East Texas reporting unit in the Southwest segment and $3.9 million allocated to the Appalachia reporting unit in the Northeast segment. In completing the evaluation, management estimated the fair value of the Partnership's reporting units primarily using an income approach based on discounted future cash flows and also considered a market approach based on the Partnership's market capitalization as of December 31, 2008.

Long-Lived Assets. The Partnership's policy is to evaluate whether there has been an impairment in the value of long-lived assets when certain events have taken place that indicate that the remaining balance may not be recoverable. The Partnership evaluates the carrying value of its property, plant and equipment and intangibles on at least a segment level and at lower levels where cash flows for specific assets can be identified.

An analysis completed during the second quarter of 2009 indicated that the future estimated operating cash flows could be at or below zero for Wirth Gathering. Wirth Gathering's expected future cash flows were adversely impacted by a significant reduction to the primary producer's drilling plan disclosed in the second quarter of 2009, as well as increased operating expenses resulting from an agreement reached in May 2009 with the non-controlling partner. The Partnership used the income approach for determining the assets' fair value and recognized an impairment of long-lived assets of approximately $5.9 million for year ended December 31, 2009. After considering the impact of the non-controlling interest, the impairment increased the net loss attributable to the Partnership for the year ended December 31, 2009 by approximately $2.9 million, before provision for income tax.

13. Impairment of Goodwill and Long-Lived Assets (Continued)

An analysis completed in 2008 indicated an impairment of the Partnership's gas-gathering assets in Manistee County, Michigan, which are part of the Partnership's Northeast segment, due to the decision to move the Fisk plant to Pennsylvania and to outsource the gas processing to a third party. The Partnership used the market approach to determine the assets' fair value and recognized an impairment of long-lived assets of $7.6 million for the year ended December 31, 2008.

14. Investment in Unconsolidated Affiliates

The Partnership applies the equity method of accounting for its 40% non-operating interest in Centrahoma Processing LLC ("Centrahoma"). Differences between the Partnership's investment and its proportionate share of reported equity are amortized based upon the respective useful lives of the assets to which the differences relate.

During 2008, the Partnership acquired a 40% interest in Centrahoma for $23.6 million. Centrahoma owns certain processing plants in the Arkoma Basin. In addition, the Partnership signed long-term agreements to dedicate the processing rights for its natural gas gathering system in the Woodford Shale to Centrahoma.

The following table includes summarized balance sheet data for 100% of Centrahoma (in thousands):

	December 31, 2010	December 31, 2009
Current assets	$16,782	$14,280
Noncurrent assets	68,394	70,922
Current liabilities	14,647	11,925

The following table includes summarized results of operations for the years ended December 31, 2010 and 2009 and from inception on February 11, 2008 to December 31, 2008 for 100% of Centrahoma (in thousands):

	Year ended December 31, 2010	Year ended December 31, 2009	Inception to December 31, 2008
Revenue	$10,768	$9,585	$6,648
Operating income (loss)	1,236	(907)	(718)
Net income (loss)	1,236	(907)	(718)
Partnership's share of net income (loss)	1,562	(451)	(277)

14. Investment in Unconsolidated Affiliates (Continued)

The Partnership applied the equity method of accounting for its 50% non-operating interest in Starfish, which was sold on December 31, 2009 for proceeds of approximately $25.0 million (see Note 5). The following table includes summarized results of operations for 100% of Starfish (in thousands):

	Year ended December 31, 2009	Year ended December 31, 2008
Revenue	$31,371	$24,088
Operating income	6,691	1,125
Net income	7,788	950
Partnership's share of net income	3,956	367

In September 2008, Hurricane Ike caused wind and water damage to oil and gas assets in the Gulf of Mexico and Gulf Coast regions, including damage to several onshore and offshore facilities of Starfish. Due to the damage in the region, the operations of Starfish were partially curtailed resulting in a decrease in the Partnership's *Earnings from unconsolidated affiliates* in the accompanying Consolidated Statements of Operations. The Partnership contributed $0.4 million and $5.0 million of additional capital to fund the repairs resulting from the hurricane for the years ended December 31, 2009 and 2008, respectively. The Partnership settled certain insurance claims related to damage and business interruption caused by Hurricane Ike in 2008. Total insurance proceeds of $0.8 million are included in *Miscellaneous income (expense), net* in the Consolidated Statements of Operations for the year ended December 31, 2009.

As a result of several impairment indicators including significant hurricane damages, a significant reduction in volumes, and a weak commodity price environment, management completed an impairment evaluation for Starfish as of December 31, 2008. Prior to completing the impairment evaluation, the recorded value of the investment in Starfish was $58.6 million. Using an income approach based on estimated discounted cash flows, management estimated that the fair value of the Partnership's investment in Starfish was approximately $17.2 million. Management concluded that the decline in value was other-than-temporary and an impairment charge of $41.4 million was recorded in the accompanying Consolidated Statements of Operations.

15. Accrued Liabilities and Other Long-Term Liabilities

Accrued liabilities consist of the following (in thousands):

	December 31, 2010	December 31, 2009
Accrued property, plant and equipment	$ 65,908	$ 60,738
Product and operations	31,241	24,301
Interest	26,607	24,193
Other	30,113	28,455
Total accrued liabilities	$153,869	$137,687

15. Accrued Liabilities and Other Long-Term Liabilities (Continued)

Other long-term liabilities consist of the following (in thousands):

	December 31, 2010	December 31, 2009
SMR Liability (see Note 5)	$ 93,909	$ 93,776
Asset retirement obligation	4,029	2,877
Other	7,411	9,083
Total other long-term liabilities	$105,349	$105,736

16. Asset Retirement Obligation

The Partnership's assets subject to asset retirement obligations are primarily certain gas-gathering pipelines and processing facilities, a crude oil pipeline and other related pipeline assets. The Partnership also has land leases that require the Partnership to return the land to its original condition upon termination of the lease. The Partnership reviews current laws and regulations governing obligations for asset retirements and leases, as well as the Partnership's leases and other agreements.

The following is a reconciliation of the changes in the asset retirement obligation from January 1, 2009 to December 31, 2010 (in thousands):

	December 31, 2010	December 31, 2009
Beginning asset retirement obligation	$2,877	$1,773
Liabilities incurred	915	906
Accretion expense	237	198
Ending asset retirement obligation	$4,029	$2,877

At December 31, 2010, 2009, and 2008, there were no assets legally restricted for purposes of settling asset retirement obligations. The asset retirement obligation has been recorded as part of *Other long-term liabilities* in the accompanying Consolidated Balance Sheets.

In addition to recorded asset retirement obligations, the Partnership has other asset retirement obligations related to certain gathering, processing and other assets as a result of environmental and other legal requirements. The Partnership is not required to perform such work until it permanently ceases operations of the respective assets. Because the Partnership considers the operational life of these assets to be indeterminable, an associated asset retirement obligation cannot be calculated and is not recorded.

17. Long-Term Debt

Debt is summarized below (in thousands):

	December 31, 2010	December 31, 2009
Credit Facility		
Revolving credit facility, 5.25% interest, due July 2015	$ —	$ 59,300
Senior Notes		
Senior Notes, 8.5% interest, net of discount of $642 and $762, respectively, issued July 2006 and due July 2016(1)	274,358	274,238
Senior Notes, 8.75% interest, net of discount of $924 and $1,051, respectively, issued April and May 2008 and due April 2018(2)	499,076	498,949
Senior Notes, 6.75% interest, issued November 2010 and due November 2020	500,000	—
Senior Notes, 6.875% interest, net of discount of $8,089, issued October 2004	—	216,911
Senior Notes, 6.875% interest, net of discount of $29,515, issued May 2009(3)	—	120,674
Total long-term debt	$1,273,434	$1,170,072

(1) On February 9, 2011, the Partnership commenced a cash tender offer for any and all of the outstanding $275.0 million aggregate principal amount of its 8.5% senior notes due 2016 (see Note 30).

(2) On February 9, 2011, the Partnership commenced a cash tender offer for up to $125.0 million aggregate principal amount of its 8.75% senior notes due 2018 (see Note 30).

(3) Includes fair value of approximately $0.2 million of written put options as of December 31, 2009 as discussed below.

Credit Facility

On February 20, 2008, the Partnership entered into a new credit agreement ("Partnership Credit Agreement"). The Partnership Credit Agreement originally provided for a maximum lending limit of $575.0 million and included a senior secured revolving credit facility ("Credit Facility") of $350.0 million (that under certain circumstances could be increased to $550.0 million) and a $225.0 million term loan, both of which could be repaid at any time without penalty. Initial borrowings under the Credit Facility were used to finance other payments under the Merger and to repay amounts due on Partnership's previous credit facility revolver of $67.0 million. The Partnership retired the term loan in April 2008 using a portion of the proceeds from a private placement of Senior Notes completed on April 15, 2008. The Partnership recorded a charge of $4.2 million to write-off the deferred financing costs associated with the term loan, which is included in *Amortization of deferred financing costs and discount* in the accompanying Consolidated Statements of Operations.

On January 28, 2009, the Partnership entered into the first amendment to its Partnership Credit Agreement which became effective March 2, 2009. The amendment expanded the borrowing capacity under the Credit Facility from $350.0 million to $435.6 million. The Partnership incurred and capitalized approximately $4.3 million of debt modification fees and other professional services as a

17. Long-Term Debt (Continued)

result of the amendment. The amendment also resulted in the write-off of approximately $0.3 million of previously capitalized deferred finance costs during the first quarter of 2009, which is included in *Amortization of deferred financing costs and discount* in the accompanying Consolidated Statements of Operations.

On July 1, 2010, the Partnership entered into an amended and restated credit agreement that initially increased the borrowing capacity of the Credit Facility to $700 million, with an uncommitted accordion feature of up to $200 million. On July 29, 2010, the Partnership executed a joinder agreement to include an additional member in the bank group participating in the Credit Facility and to exercise a portion of the accordion feature under the Credit Facility, thereby increasing the borrowing capacity to $705 million and reducing the uncommitted accordion feature to $195 million. The Credit Facility matures on July 1, 2015. The Partnership incurred approximately $11.2 million of deferred financing costs associated with the modification of the Credit Facility.

The borrowings under the Credit Facility bear interest at a variable interest rate, plus basis points. The variable interest rate is based either on LIBOR ("LIBOR Loans") or the higher of (a) the prime rate set by the Credit Facility's administrative agent, (b) the Federal Funds Rate plus 0.5% and (c) the rate for LIBOR for a one month interest period plus 1% ("Alternate Base Rate Loans"). The basis points correspond to the ratio of the Partnership's Consolidated Funded Debt (as defined in the Credit Facility) to the Partnership's Adjusted Consolidated EBITDA (as defined in the Credit Facility), ranging from 1.5% to 2.5% for Alternate Base Rate Loans and from 2.5% to 3.5% for LIBOR Loans. The Partnership may utilize up to $150 million of the Credit Facility for the issuance of letters of credit and $10 million for shorter term swingline loans.

Under the provisions of the Credit Facility, the Partnership is subject to a number of restrictions and covenants. Significant financial covenants under the Credit Facility include the Interest Coverage Ratio (as defined in the Credit Facility), which must be greater than 2.75 to 1.0, and the Total Leverage Ratio (as defined in the Credit Facility), which must be less than 5.25 to 1.0. As of December 31, 2010, the Partnership was in compliance with these covenants. These covenants are used to calculate the available borrowing capacity on a quarterly basis. The Credit Facility is guaranteed and collateralized by substantially all of the Partnership's assets and those of its wholly-owned subsidiaries. As of December 31, 2010, the Partnership had no borrowings outstanding and $27.4 million of letters of credit outstanding under the Credit Facility, leaving approximately $677.6 million available for borrowing.

Senior Notes

As of December 31, 2010, MarkWest Energy Partners, L.P. in conjunction with its wholly-owned subsidiary MarkWest Energy Finance Corporation (the "Issuers"), had three series of senior notes outstanding: $275.0 million aggregate principal issued in July 2006 and due in July 2016 (the "2016 Senior Notes"), $500.0 million aggregate principal issued in April and May 2008 and due in April 2018 (the "2018 Senior Notes"), and $500.0 million aggregate principal issued in November 2010 and due in November 2020 (the "2020 Senior Notes" and all together with the 2016 Senior Notes and 2018 Senior Notes, the "Senior Notes").

17. Long-Term Debt (Continued)

2014 Senior Notes. In October 2004, the Issuers completed a private placement, subsequently registered, of $225.0 million in senior notes at a fixed rate of 6.875%, payable semi-annually in arrears on May 1 and November 1, commencing May 1, 2005.

2014 Senior Notes—Mirror. In May 2009, the Issuers completed a private placement, subsequently registered, of $150.0 million in aggregate principal amount of 6.875% senior unsecured notes to qualified institutional buyers under Rule 144A. Although the terms of the 2014 Senior Notes—Mirror were substantially the same as the terms of the 2014 Senior Notes, the 2014 Senior Notes—Mirror were issued under a different indenture and were not part of the same series of notes. The Partnership received proceeds of approximately $113.8 million, after deducting the underwriting fees and other third-party expenses associated with the private placement. The proceeds were primarily used to repay borrowings under the Credit Facility. Interest on these senior notes was payable on each May 1 and November 1, and accrued from May 26, 2009.

The 2014 Senior Notes and the 2014 Senior Notes—Mirror were redeemed in the fourth quarter of 2010. The Partnership recorded a pre-tax loss of approximately $46.3 million in the fourth quarter of 2010, which consists of approximately $36.6 million related to the non-cash write-off of the unamortized discount and deferred finance costs and approximately $9.7 million related to the payment of premiums. This loss is recorded in *Loss on redemption of debt* in the accompanying Consolidated Statements of Operations.

2016 Senior Notes. In July 2006, the Issuers completed a private placement, subsequently registered, of $200 million in aggregate principal amount of 8.5% senior notes due 2016 to qualified institutional buyers. The 2016 Senior Notes mature on July 15, 2016, and interest is payable semi-annually in arrears on July 15 and January 15, commencing January 15, 2007. In October 2006 the Partnership offered $75.0 million in additional debt securities under this same indenture.

2018 Senior Notes. In April 2008, the Issuers completed a private placement, subsequently registered, of $400 million in aggregate principal amount of 8.75% senior notes to qualified institutional buyers under Rule 144A. The 2018 Senior Notes mature on April 15, 2018, and interest is payable semi-annually in arrears on April 15 and October 15, commencing October 15, 2008. The Partnership received proceeds of approximately $388.1 million, after deducting the underwriting fees and the other expenses of the offering. Also, on May 1, 2008, the Partnership completed the placement of an additional $100.0 million pursuant to the indenture to the 2018 Senior Notes. The Partnership received approximately $100.4 million, after including initial purchasers' premium and deducting the third-party expenses associated with the offering. The notes issued in this offering and the notes issued on April 15, 2008, are treated as a single class of debt securities under this same indenture. The Partnership utilized approximately $275.0 million of the net proceeds from the offerings to repay the $225.0 million term loan portion of the Partnership Credit Agreement entered into on February 20, 2008 and to partially fund its 2008 capital expenditure requirements.

2020 Senior Notes. On November 2, 2010, the Issuers completed a public offering of $500 million in aggregate principal amount of 6.75% senior unsecured notes. The 2020 Senior Notes mature on November 1, 2020, and interest is payable semi-annually in arrears on May 1 and November 1, commencing May 1, 2011. The Partnership received proceeds of approximately $490.3 million after deducting the underwriting fees and the other third-party expenses associated with the offering. The Partnership used a portion of the net proceeds from the 2020 Senior Notes offering to redeem the 2014

17. Long-Term Debt (Continued)

Senior Notes and the 2014 Senior Notes—Mirror as discussed above. The remaining proceeds were used to repay all borrowings outstanding under the Credit Facility and to provide working capital for general partnership purposes.

The Issuers have no independent operating assets or operations. All wholly-owned subsidiaries, other than MarkWest Energy Finance Corporation, guarantee the Senior Notes, jointly and severally and fully and unconditionally. The Partnership's less than wholly-owned subsidiaries do not guarantee the Senior Notes (see Note 26 for required consolidating financial information). The notes are senior unsecured obligations equal in right of payment with all of the Partnership's existing and future senior debt. These notes are senior in right of payment to all of the Partnership's future subordinated debt but effectively junior in right of payment to its secured debt to the extent of the assets securing the debt, including the Partnership's obligations in respect of the Partnership Credit Agreement.

The indentures governing the Senior Notes limit the activity of the Partnership and its restricted subsidiaries. Subject to compliance with certain covenants, the Partnership may issue additional notes from time to time under the indentures pursuant to Rule 144A and Regulation S under the Securities Act of 1933. If at any time the Senior Notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Rating Services and no default (as defined in the indentures) has occurred and is continuing, many of such covenants will be suspended during the period of time in which the foregoing requirements are met or will terminate entirely, in which case the Partnership and its subsidiaries will cease to be subject to such terminated covenants.

As of December 31, 2010, there are no minimum principal payments on long-term debt due during the next five years. The full $1,275 million principal amount is due between 2016 and 2020. See Note 30 for discussion of Senior Notes transactions subsequent to December 31, 2010.

Embedded Put Option

The indenture for the 2014 Senior Notes—Mirror contained the following two contingent written put options exercisable by the debt holders (see Note 6 for more information on the separate accounting for the written put options and Note 7 for more information on the determination of the fair value):

Change in Control Put—In the event of a change in control of the Partnership, the debt holders had the option to put the notes at 101% of principal amount, plus any accrued interest.

Asset Sale Offer Put—In the event the Partnership consummated an asset sale, as defined in the indenture, and failed to use the net proceeds in excess of $10.0 million to: (i) pay off indebtedness under the Credit Facility; (ii) to make capital expenditures; (iii) to acquire other long-term tangible assets or (iv) to invest the proceeds in any other approved investment, the Partnership must have used the excess proceeds to offer to repurchase some portion of the senior notes at 100% of principal amount, plus any accrued interest.

The written put options were considered embedded derivatives primarily due to the fact that they were contingently exercisable and the notes were issued at a substantial discount. Substantially similar contingent written put options are also in the indentures for the Partnership's other Senior Note offerings, but they do not require separate accounting because their issuance was not at a substantial discount.

18. Equity

As described in Note 3, the Partnership acquired the Corporation through a merger of MWEP, L.L.C. with and into the Corporation, pursuant to which all remaining shares of the Corporation's common stock were converted into approximately 15.5 million Partnership common units. The Partnership Agreement stipulates the circumstances under which the Partnership is authorized to issue new capital, maintain capital accounts, and distribute cash.

The Partnership Agreement contains specific provisions for the allocation of net income and losses to each of the partners for purposes of maintaining their respective partner capital accounts.

Distributions of Available Cash

The Partnership distributes all of its Available Cash (as defined) to unitholders of record within 45 days after the end of each quarter. Available Cash is generally defined as all cash and cash equivalents of the Partnership on hand at the end of each quarter, less reserves established by the general partner for future requirements, plus all cash for the quarter from working capital borrowings made after the end of the quarter. The general partner has the discretion to establish cash reserves that are necessary or appropriate to (i) provide for the proper conduct of the Partnership's business; (ii) comply with applicable law, any debt instruments or other agreements; or (iii) provide funds for distributions to unitholders and the general partner for any one or more of the next four quarters.

The quarterly cash distributions applicable to 2010, 2009 and 2008, were as follows:

Quarter Ended	Record Date	Payment Date	Amount Per Unit
December 31, 2010	February 7, 2011	February 14, 2011	$0.65
September 30, 2010	November 8, 2010	November 12, 2010	$0.64
June 30, 2010	August 2, 2010	August 13, 2010	$0.64
March 31, 2010	May 3, 2010	May 14, 2010	$0.64
December 31, 2009	February 5, 2010	February 12, 2010	$0.64
September 30, 2009	November 2, 2009	November 13, 2009	$0.64
June 30, 2009	August 3, 2009	August 14, 2009	$0.64
March 31, 2009	May 4, 2009	May 15, 2009	$0.64
December 31, 2008	February 6, 2009	February 13, 2009	$0.64
September 30, 2008	November 4, 2008	November 14, 2008	$0.64
June 30, 2008	August 4, 2008	August 15, 2008	$0.63
March 31, 2008	May 5, 2008	May 15, 2008	$0.60

Equity Offerings

On April 6, 2010, the Partnership completed a public offering of approximately 4.9 million newly issued common units, which included the exercise of the overallotment option by the underwriters, representing limited partner interests at a purchase price of $30.43 per common unit. Net proceeds of approximately $142.3 million were used to repay borrowings under its Credit Facility and to partially fund the Partnership's ongoing capital expenditure program.

On August 18, 2009, the Partnership completed a public offering of approximately 6.03 million newly issued common units, which included the exercise of the overallotment option by the underwriters, representing limited partner interests at a purchase price of $20.95 per common unit. Net

18. Equity (Continued)

proceeds of approximately $120.9 million were used to partially fund the Partnership's 2009 capital expenditure requirements, and the remainder was used to pay down borrowings under its Credit Facility.

On June 10, 2009, the Partnership completed a public offering of approximately 3.34 million newly issued common units, which included the exercise of the overallotment option by the underwriters, representing limited partner interests at a purchase price of $18.15 per common unit. Net proceeds of approximately $57.7 million were used to partially fund the Partnership's 2009 capital expenditure requirements, and the remainder was used to pay down borrowings under its Credit Facility.

On April 14, 2008, the Partnership completed a public offering of 5.75 million newly issued common units, which included the exercise of the overallotment option by the underwriters, representing limited partner interests at a purchase price of $31.15 per common unit. Net proceeds of approximately $171.4 million were used to pay down borrowings under its Credit Facility, and the remainder was used to partially fund the Partnership's 2008 capital expenditure requirements.

19. Commitments and Contingencies

Legal

The Partnership is subject to a variety of risks and disputes, and is a party to various legal proceedings in the normal course of its business. The Partnership maintains insurance policies in amounts and with coverage and deductibles as it believes reasonable and prudent. However, the Partnership cannot assure that the insurance companies will promptly honor their policy obligations or that the coverage or levels of insurance will be adequate to protect the Partnership from all material expenses related to future claims for property loss or business interruption to the Partnership, or for third-party claims of personal and property damage, or that the coverages or levels of insurance it currently has will be available in the future at economical prices. While it is not possible to predict the outcome of the legal actions with certainty, management is of the opinion that appropriate provisions and accruals for potential losses associated with all legal actions have been made in the consolidated financial statements.

In June 2006, the Office of Pipeline Safety ("OPS") issued a Notice of Probable Violation and Proposed Civil Penalty ("NOPV") (CPF No. 2-2006-5001) to both MarkWest Hydrocarbon and Equitable Production Company ("Equitable"). The NOPV is associated with the pipeline leak and an ensuing explosion and fire that occurred on November 8, 2004 in Ivel, Kentucky on an NGL pipeline owned by Equitable and leased and operated by a subsidiary of the Partnership, MarkWest Energy Appalachia, L.L.C. The NOPV sets forth six counts of violations of applicable regulations, and a proposed civil penalty in the aggregate amount of $1.1 million. An administrative hearing on the matter, previously set for the last week of March 2007, was postponed to allow the administrative record to be produced and to allow OPS an opportunity to respond to MarkWest's and Equitable's motions to dismiss count one of the NOPV, which involves $0.8 million of the $1.1 million proposed penalty. This count arises out of alleged activity in 1982 and 1987, which predates MarkWest's leasing and operation of the pipeline. MarkWest believes it has viable and mitigating defenses to the remaining counts and will vigorously defend all applicable assertions of violations. The administrative hearing request was withdrawn by MarkWest and Equitable in October 2009, and the parties are waiting for initial resolution on the briefs, exhibits and other documents filed or submitted by the parties in the matter.

19. Commitments and Contingencies (Continued)

In the ordinary course of business, the Partnership is a party to various other legal and regulatory actions. In the opinion of management, none of these actions, either individually or in the aggregate, will have a material adverse effect on the Partnership's financial condition, liquidity or results of operations.

Lease and Other Contractual Obligations

The Partnership has various non-cancelable operating lease agreements and a long-term propane storage agreement expiring at various times through fiscal year 2035. Annual expense under these agreements was $18.4 million, $18.6 million and $12.8 million for the years ended December 31, 2010, 2009 and 2008, respectively. The minimum future payments under these agreements as of December 31, 2010, are as follows (in thousands):

Year ending December 31,	
2011	$ 7,893
2012	7,974
2013	7,453
2014	7,351
2015	7,388
2016 and thereafter	16,154
	$54,213

SMR Transaction

On September 1, 2009, the Partnership entered into a product supply agreement creating a long-term contractual obligation for the payment of processing fees in exchange for all of the product processed by the SMR (see Note 5 for further discussion of this agreement and the related SMR Transaction). The product received under this agreement will be sold to a refinery customer pursuant to a corresponding long-term agreement. The minimum amounts payable annually under the product supply agreement, excluding the potential impact of inflation adjustments per the agreement, are as follows (in thousands):

Year ending December 31,	
2011	$ 17,412
2012	17,412
2013	17,412
2014	17,412
2015	17,412
2016 and thereafter	247,441
Total minimum payments	334,501
Less: Services element	127,955
Less: Interest	110,762
Less: Current portion of SMR Liability	1,875
Long-term portion of SMR Liability	$ 93,909

20. Lease Operations

Based on the terms of certain natural gas gathering and natural gas transportation agreements, the Partnership is considered to be the lessor under several implicit operating lease arrangements in accordance with GAAP. The Partnership's primary implicit lease operations relate to a natural gas gathering agreement in the Liberty segment for which it earns a fixed-fee for providing gathering services to a single producer using a dedicated gathering system. As the gathering system is expanded the fixed-fee charged to the producer is adjusted to include the additional gathering assets in the lease. The primary term of the natural gas gathering arrangement expires in 2024 and will continue thereafter on a year to year basis until terminated by either party.

The Partnership's revenue from its implicit lease arrangements totaled approximately $32.2 million, $14.9 million and $4.2 million for the years ended December 31, 2010, 2009 and 2008, respectively. The Partnership's implicit lease arrangements do not contain any contingent rental provisions. The following is a schedule of minimum future rentals on the non-cancellable operating leases as of December 31, 2010 (in thousands):

Year ending December 31,	
2011	$ 47,246
2012	47,246
2013	47,246
2014	47,246
2015	47,246
2016 and thereafter	381,069
Total minimum future rentals	$617,299

The following schedule provides an analysis of the Partnership's investment in assets held for operating lease by major classes as of December 31, 2010 and 2009 (in thousands):

	December 31, 2010	December 31, 2009
Natural gas gathering and NGL transportation pipelines and facilities	$264,669	$176,074
Construction in progress	60,170	14,697
Property, plant and equipment	324,839	190,771
Less: accumulated depreciation	(21,742)	(10,220)
Total property, plant and equipment, net	$303,097	$180,551

21. Incentive Compensation Plans

As of December 31, 2010, the Partnership had the following active share-based compensation plans which are administered by the Compensation Committee of the General Partner's board of directors ("Compensation Committee").

Share-based compensation plan	Plan qualification under Stock Compensation	Further awards authorized for issuance under plan
2008 Long-Term Incentive Plan ("2008 LTIP")	Equity awards	Yes
Long-Term Incentive Plan ("2002 LTIP")	Liability awards	No

As of December 31, 2009, the Partnership had an additional share-based compensation plan: the 2006 Hydrocarbon Stock Incentive Plan ("2006 Hydrocarbon Plan"). The 2006 Hydrocarbon Plan awards qualified as equity awards. The last awards issued under the 2006 Hydrocarbon Plan vested in 2010 and there were no further awards authorized for issuance; therefore, the 2006 Hydrocarbon Plan was no longer active as of December 31, 2010.

As of December 31, 2008, the Partnership had an additional share-based compensation plan: the 1996 Hydrocarbon Stock Incentive Plan ("1996 Hydrocarbon Plan"). The 1996 Hydrocarbon Plan awards qualified as equity awards. The last awards issued under the 1996 Hydrocarbon Plan vested in 2009 and there were no further awards authorized for issuance; therefore, the 1996 Hydrocarbon Plan was no longer active as of December 31, 2010.

Compensation Expense

Total compensation expense recorded for share-based pay arrangements was as follows (in thousands):

	Year ended December 31,		
	2010	2009	2008
Phantom units	$15,319	$7,448	$11,348
Distribution equivalent rights(1)	1,465	1,324	701
Restricted stock	—	—	75
General partner interests under Participation Plan	—	—	5,470
Total compensation expense	$16,784	$8,772	$17,594

(1) A distribution equivalent right is a right, granted in tandem with a specific phantom unit, to receive an amount in cash equal to, and at the same time as, the cash distributions made by the Partnership with respect to a unit during the period such phantom unit is outstanding. Payment of distribution equivalent rights associated with units that are expected to vest are recorded as capital distributions, however, payments associated with units that are not expected to vest are recorded as compensation expense.

Compensation expense under the share-based compensation plans has been recorded as either *Selling, general and administrative expenses* or *Facility expenses* in the accompanying Consolidated Statements of Operations.

21. Incentive Compensation Plans (Continued)

As of December 31, 2010, total compensation expense not yet recognized related to the unvested awards under the 2008 LTIP was approximately $21.0 million, with a weighted average remaining vesting period of approximately 0.8 years. Total compensation expense not yet recognized includes approximately $2.7 million related to the TUR Performance Units (see discussion of TUR Performance Units below). Total compensation expense not yet recognized related to unvested awards under the 2002 LTIP was approximately $0.1 million, with a weighted-average remaining vesting period of approximately 0.1 years. The actual compensation expense recognized for awards under the 2002 LTIP may differ as they qualify as liability awards, which are affected by changes in fair value.

Summary of Equity Awards

Awards under the 2008 LTIP, 2006 Hydrocarbon Plan and 1996 Hydrocarbon Plan qualify as equity awards. Accordingly, the fair value is measured at the grant date using the market price of the Partnership's common units. A phantom unit entitles an employee to receive a common unit upon vesting. The Partnership generally issues new common units upon vesting of phantom units. Compensation expense related to service-based awards is recognized over the requisite service period, reduced for an estimate of expected forfeitures. Phantom units generally vest equally over a three-year period. Compensation expense related to performance-based awards is recognized when probability of vesting is established, as discussed below. As part of a net settlement option, employees may elect to surrender a certain number of phantom units, and in exchange, the Partnership will assume the income tax withholding obligations related to the vesting. Phantom units surrendered for the payment of income tax withholdings will again become available for issuance under the plan from which the awards were initially granted, provided that further awards are authorized for issuance under the plan. The Partnership was required to pay approximately $3.4 million, $1.1 million and $0.1 million during the years ended December 31, 2010, 2009 and 2008, respectively, for income tax withholdings related to the vesting of equity awards. The Partnership received no proceeds from the issuance of phantom units, and none of the phantom units that vested were redeemed by the Partnership for cash.

2008 LTIP

The 2008 LTIP was approved by unitholders on February 21, 2008. The 2008 LTIP provides 2.5 million common units for issuance to the Corporation's employees and affiliates as share-based payment awards. The 2008 LTIP was created to attract and retain highly qualified officers, directors, and other key individuals and to motivate them to serve the General Partner, the Partnership and their affiliates and to expend maximum effort to improve the business results and earnings of the Partnership and its affiliates. Awards authorized under the 2008 LTIP include unrestricted units, restricted units, phantom units, distribution equivalent rights, and performance awards to be granted in any combination.

TUR Performance Units. In April 2010, the Board granted 282,000 performance phantom units ("TUR Performance Units") under the 2008 LTIP to senior executives and other key employees. The TUR Performance Units are classified as equity awards and do not contain distribution equivalent rights. The TUR Performance Units vest in two equal installments on January 31, 2011 and January 31, 2012, subject to the Partnership's relative total unitholder return (unit price appreciation and distribution performance) over the three-year calendar period prior to the scheduled vesting date compared to the total unitholder return of a defined group of peer companies over the same period

21. Incentive Compensation Plans (Continued)

("Market Criteria"). The TUR Performance Units will vest in accordance with the Partnership's relative ranking compared to the peer companies. Zero TUR Performance Units will vest if the Partnership's relative ranking is less than the 40th percentile; 50% of the TUR Performance Units will vest if the Partnership's relative ranking is in the 40th to 60th percentile; 75% of the TUR Performance Units will vest if the Partnership's relative ranking is in the 60th to 80th percentile; and 100% of the TUR Performance Units will vest if the Partnership's relative ranking is in the 80th to 100th percentile.

Additionally, the Board can increase or decrease the number of units to vest by up to 25% of the number of units that would otherwise vest based solely on the Market Criteria based on other performance criteria to be determined at the Board's discretion ("Performance Criteria"). The effect of these conditions is that vesting of 75%, or 211,500, of the TUR Performance Units will be determined solely by the Partnership's actual performance with regards to the Market Criteria. The remaining 25%, or 70,500, of the TUR Performance Units will vest based on a combination of the Market Criteria and the Performance Criteria. In January 2011, the Board exercised its discretion to vest the full 35,250 additional units related to the January 31, 2011 vesting installment.

The fair value of the TUR Performance Units is estimated using a Monte Carlo simulation model that determines the most likely outcome based on the terms of the award. The key inputs in the model include the market price of the Partnership's common units as of the valuation date, the historical volatility of the market price of the Partnership's common units, the historical volatility of the market price of the common units or common stock of the peer companies, and the correlation between changes in the market price of the Partnership's common units and those of the peer companies. Compensation expense related to 211,500 of the TUR Performance Units is recognized over the requisite service period based on the fair value of the units as of the grant date. However, a grant date, as defined by GAAP, has not been established for the other 70,500 TUR Performance Units because the Performance Criteria prevents a mutual understanding of the key terms of the award. Therefore, compensation expense related to 70,500 of the TUR Performance Units is recognized over the requisite service period based on the fair value of the units as of the current reporting date. The requisite service period for all TUR Performance Units began in April 2010 when the Board approved the awards. Compensation expense for the 70,500 TUR Performance Units may increase or decrease based on the probability of achieving the Performance Criteria. Compensation expense recognized related to TUR Performance Units was approximately $4.5 million the year ended December 31, 2010.

Unrestricted Units. In January 2010, the Board granted 166,000 unrestricted units to senior executives and other key employees under the 2008 LTIP. The unrestricted units vested immediately and the Partnership recognized approximately $4.8 million of expense related to these units.

Performance Units. Phantom units containing performance vesting criteria ("Performance Units") have been granted to senior executives and other key employees under the 2008 LTIP. The Performance Units vest on a performance-based schedule generally over a three-year period, and vesting of these units occurs if the Partnership achieves established performance goals determined by the Compensation Committee. Management will conduct a quantitative analysis on an ongoing basis to assess the probability of meeting the established performance goals and will record compensation expense as required. As of December 31, 2010, there were 437,100 Performance Units outstanding with a grant date fair value of $10.6 million. Compensation expense recorded for the Performance Units expected to vest was approximately zero, $0.5 million and $4.1 million for the years ended December 31, 2010, 2009 and 2008, respectively.

21. Incentive Compensation Plans (Continued)

2006 Hydrocarbon Plan and 1996 Hydrocarbon Plan

On February 21, 2008, the 25,897 outstanding shares of restricted stock held by 43 employees and directors granted under the 2006 Hydrocarbon Plan and 1996 Hydrocarbon Plan were converted to 49,354 phantom units in connection with the Merger. The conversion qualified as a modification, requiring the Partnership to compare the grant date fair value of the original awards with the converted awards. As a result of the comparison, the Partnership determined that the fair value of the awards had increased by $0.5 million. Approximately $0.4 million of the fair value was expensed in the first quarter of 2008; the remaining $0.1 million was amortized as compensation expense over the remaining vesting period of less than one year. The converted phantom unit awards remained outstanding under the terms of the 2006 Hydrocarbon Plan and 1996 Hydrocarbon Plan until their respective settlement dates. There are no converted phantom units outstanding under the 2006 Hydrocarbon Plan or the 1996 Hydrocarbon Plan as of December 31, 2010.

The following is a summary of phantom unit activity under the 2008 LTIP, 2006 Hydrocarbon Plan and 1996 Hydrocarbon Plan:

	Number of Units	Weighted-average Grant-date Fair Value(2)
Unvested at January 1, 2008	—	$ —
Granted(1)	928,685	31.78
Vested	(17,274)	31.79
Forfeited	(2,105)	25.92
Unvested at December 31, 2008	909,306	31.80
Granted	442,035	8.64
Vested	(309,052)	31.93
Forfeited	(65,048)	20.96
Unvested at December 31, 2009	977,241	22.00
Granted	736,688	29.48
Vested	(363,502)	26.85
Forfeited	(21,267)	19.28
Unvested at December 31, 2010	1,329,160	24.86

(1) Includes 49,354 restricted shares converted to phantom units pursuant to the terms of the redemption and merger agreement.

(2) The calculation of the weighted average grant-date fair value for units granted during the year ended December 31, 2010 includes the fair value as of December 31, 2010 for 70,500 TUR Performance Units. A grant date, as defined by GAAP, has not been established for these units.

21. Incentive Compensation Plans (Continued)

	Year ended December 31,		
	2010	2009	2008
	(in thousands)		
Total grant-date fair value of phantom units granted during the period(1)	$21,717	$3,819	$29,516
Total fair value of phantom units vested during the period and total intrinsic value of phantom units settled during the period	$ 9,760	$9,867	$ 549

(1) The calculation of the grant-date fair value for units granted during the year ended December 31, 2010 includes the fair value of $4.3 million for 211,500 TUR Performance Units. The calculation of the grant-date fair value for units granted during the year ended December 31, 2010 also includes the fair value of $2.9 million as of December 31, 2010 for the remaining 70,500 TUR Performance Units; a grant date, as defined by GAAP, has not been established for these units.

2002 LTIP

The phantom units awarded under the 2002 LTIP are classified as liability awards. Accordingly, the fair value of the outstanding awards is re-measured at the end of each reporting period using the market price of the Partnership's common units. The fair value of the phantom units awarded is amortized into earnings as compensation expense over the vesting period, which is generally three years. A phantom unit entitles an employee to receive a common unit upon vesting, or at the discretion of the Compensation Committee, the cash equivalent to the value of a common unit. The Partnership generally issues new common units upon the vesting of phantom units. As part of a net settlement option, employees may elect to surrender a certain number of phantom units, and in exchange, the Partnership will assume the income tax withholding obligations related to the vesting. The Partnership received no proceeds (other than the contributions by the General Partner to maintain its 2% ownership interest prior to the Merger) for issuing phantom units and none of the phantom units that vested were redeemed by the Partnership for cash. The amounts paid by the Partnership for income tax withholdings related to the vesting of awards under the 2002 LTIP were $0.4 million and $0.2 million for the years ended December 31, 2010 and 2009, respectively.

The following is a summary of phantom unit activity under the 2002 LTIP:

	Number of Units	Weighted-average Grant-date Fair Value
Unvested at January 1, 2008	125,250	$27.42
Granted	78,540	34.00
Vested	(57,214)	26.11
Forfeited	(649)	33.64
Unvested at December 31, 2008	145,927	31.45
Granted	—	—
Vested	(69,652)	29.94
Forfeited	(6,720)	33.64
Unvested at December 31, 2009	69,555	32.75
Granted	—	—
Vested	(44,942)	32.15
Forfeited	(968)	34.00
Unvested at December 31, 2010	23,645	33.83

21. Incentive Compensation Plans (Continued)

	Year ended December 31,		
	2010	2009	2008
	(in thousands)		
Total grant-date fair value of phantom units granted during the period	$ —	$ —	$2,670
Total fair value of phantom units vested during the period and total intrinsic value of phantom units settled during the period	$1,312	$920	$1,943

Participation Plan

The interests in the Partnership's General Partner sold by the Corporation to certain directors and employees were referred to as the Participation Plan. The Participation Plan was considered a compensatory arrangement and the General Partner interests were classified as liability awards. As a result, the Corporation was required to calculate the fair value of the General Partner interests at the end of each period. In conjunction with the Merger, all of the outstanding interests in the General Partner were acquired for a combination of 0.9 million common units with a fair value of approximately $30.1 million and approximately $21.5 million in cash.

Hydrocarbon Stock Options

On or before February 21, 2008, the remaining 51,509 Hydrocarbon stock options outstanding were exercised or deemed exercised. The following summarizes the impact of the Corporation's stock options (in thousands):

	Year ended December 31, 2008
Options exercised, cashless	1
Shares issued, cashless	1
Options exercised, cash	50
Shares issued, cash	50

A summary of the status of the Corporation's stock option plan as of December 31, 2008 is presented below.

	Number of Shares	Weighted-average Exercise Price
Outstanding at January 1, 2008	51,509	$7.21
Exercised	(51,509)	7.21
Outstanding at December 31, 2008	—	—

For the year ended December 31, 2008, the Corporation received $0.4 million for the exercise of stock options. The intrinsic value of the options exercised during the year ended December 31, 2008 was $2.9 million. The fair value of the options vesting for the year ended December 31, 2008 was zero.

Tax effects of share-based compensation

The Partnership elected to adopt the simplified method to establish the beginning balance of the additional paid-in capital pool ("APIC Pool") related to the tax effects of employee share-based

21. Incentive Compensation Plans (Continued)

compensation, and to determine the subsequent impact on the APIC Pool and Consolidated Statements of Cash Flows of the tax effects of share-based compensation awards that were outstanding upon adoption. APIC is reported as common units in the accompanying Consolidated Balance Sheets as a result of the Merger. Cash flows resulting from tax deductions in excess of the cumulative compensation cost recognized for share-based compensation awards exercised are classified as financing cash flows and are included as *Excess tax benefits related to share-based compensation* in the accompanying Consolidated Statements of Cash Flows.

22. Employee Benefit Plan

All employees dedicated to, or otherwise principally supporting the Partnership are employees of MarkWest Hydrocarbon, and substantially all of these employees are participants in MarkWest Hydrocarbon's defined contribution benefit plan. The employer matching contribution expense related to this plan was $2.3 million, $1.8 million and $1.6 million for the years ended December 31, 2010, 2009 and 2008, respectively.

23. Income Tax

The components of the provision for income tax expense (benefit) are as follows (in thousands):

	Year ended December 31,		
	2010	2009	2008
Current income tax expense:			
Federal	$ 5,850	$ 6,525	$12,947
State	1,805	1,547	2,085
Total current	7,655	8,072	15,032
Deferred income tax (benefit) expense:			
Federal	(3,870)	(43,409)	50,129
State	(596)	(6,679)	3,669
Total deferred	(4,466)	(50,088)	53,798
Provision for income tax	$ 3,189	$(42,016)	$68,830

23. Income Tax (Continued)

A reconciliation of the provision for income tax and the amount computed by applying the federal statutory rate of 35% to the income before income taxes for the years ended December 31, 2010, 2009 and 2008 is as follows (in thousands):

Year ended December 31, 2010:

	Corporation	Partnership	Eliminations	Consolidated
(Loss) income before provision for income tax	$(8,120)	$47,761	$(5,350)	$34,291
Federal statutory rate	35%	0%	0%	
Federal income tax at statutory rate	(2,842)	—	—	(2,842)
Permanent items	20	—	—	20
State income taxes net of federal benefit	(272)	1,299	—	1,027
Current year change in valuation allowance	(1,022)	—	—	(1,022)
Prior period adjustments and tax rate changes	70	—	—	70
Provision on income from Class A units(1)	5,753	—	—	5,753
Other	183	—	—	183
Provision for income tax	$ 1,890	$ 1,299	$ —	$ 3,189

Year ended December 31, 2009:

	Corporation	Partnership	Eliminations	Consolidated
Loss before provision for income tax	$(112,506)	$(32,800)	$(10,064)	$(155,370)
Federal statutory rate	35%	0%	0%	
Federal income tax at statutory rate	(39,377)	—	—	(39,377)
Permanent items	1	—	—	1
State income taxes net of federal benefit	(4,186)	(1,439)	—	(5,625)
Current year change in valuation allowance	1,562	—	—	1,562
Tax rate changes	1,497	—	—	1,497
Provision on income from Class A units(1)	(525)	—	—	(525)
Write-off of deferred income tax assets	293	—	—	293
Other	158	—	—	158
Provision for income tax	$ (40,577)	$ (1,439)	$ —	$ (42,016)

23. Income Tax (Continued)

Year ended December 31, 2008:

	Corporation	Partnership	Eliminations	Consolidated
Income before provision for income tax	$101,146	$174,702	$(2,246)	$273,602
Federal statutory rate	35%	0%	0%	
Federal income tax at statutory rate	35,401	—	—	35,401
Permanent items	(116)	—	—	(116)
State income taxes net of federal benefit	2,433	1,617	—	4,050
Current year change in valuation allowance	(120)	—	—	(120)
Provision on income from Class A units(1)	22,484	—	—	22,484
Write-off of deferred income tax assets(2)	7,471	—	—	7,471
Other	(340)	—	—	(340)
Provision for income tax	$ 67,213	$ 1,617	$ —	$ 68,830

(1) The Corporation pays tax on its share of the Partnership's income or loss as a result of its ownership of Class A units as discussed in Note 2.

(2) Represents the write-off of certain deferred tax assets that as an indirect result of the Merger will no longer be realized.

23. Income Tax (Continued)

The deferred tax assets and liabilities resulting from temporary book-tax differences are comprised of the following (in thousands):

	December 31, 2010	December 31, 2009
Current deferred tax assets		
Accruals and reserves	$ 64	$ 66
Derivative instruments	16,031	12,172
Current deferred tax assets	16,095	12,238
Current deferred tax liabilities		
Derivative instruments	16	10
Current deferred tax liabilities	16	10
Current subtotal	16,079	12,228
Long-term deferred tax assets		
Accruals and reserves	34	2
Derivative instruments	14,241	15,585
Uncertain tax positions liability	—	8
Phantom unit compensation	1,684	1,165
Capital loss carryforward	975	1,571
State net operating loss carryforward	156	211
Long-term deferred tax assets	17,090	18,542
Valuation allowance	(1,036)	(1,688)
Net long-term deferred tax assets	16,054	16,854
Long-term deferred tax liabilities		
Property, plant and equipment and intangibles	3,529	3,344
Phantom unit compensation	31	29
Investment in consolidated subsidiaries	22,891	24,484
Derivative instruments	30	31
Long-term deferred tax liabilities	26,481	27,888
Long-term subtotal	(10,427)	(11,034)
Net deferred tax asset	$ 5,652	$ 1,194

Significant judgment is required in evaluating tax positions and determining the Corporation's provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The Corporation establishes reserves for uncertain tax positions based on estimates of whether, and the extent to which, additional taxes will be due. These reserves are established when the Corporation believes that certain positions might be challenged despite the Corporation's belief that its tax return positions are fully supportable. The Corporation adjusts these reserves in light of changing facts and circumstances, such as the outcome of tax audits. The provision for income taxes includes the impact of reserve provisions and changes to reserves that are considered appropriate.

23. Income Tax (Continued)

The reconciliation of the Corporation's accrual for uncertain tax positions is as follows (in thousands):

	Year ended December 31,		
	2010	2009	2008
Tax contingencies—beginning of period	$ 8	$ 247	$ 747
Changes to current period tax positions	(8)	(239)	(500)
Tax contingencies—end of period	$—	$ 8	$ 247

As of December 31, 2010, the Corporation had state net operating loss carryforwards of approximately $1.3 million that expire between 2011 and 2029. The Corporation expects that future taxable income will likely be apportioned to states other than those in which the net operating loss was generated. As a result, the Corporation believes it is more likely than not that the state net operating losses will not be realized and has provided a 100% valuation allowance against this long-term deferred tax asset. As of December 31, 2010, the Corporation had a capital loss carryforward of approximately $1.0 million that expires in 2014. The Corporation does not anticipate utilizing this carryforward and has provided a 100% valuation allowance against this long-term deferred tax asset. While the Corporation's consolidated federal tax return and any significant state tax returns are not currently under examination, the tax years 2007 through 2009 remain open to examination by the major taxing jurisdictions to which the Corporation is subject.

24. (Loss) Earnings Per Common Unit

The following table shows the computation of basic and diluted net (loss) income per common unit, for the years ended December 31, 2010, 2009 and 2008, respectively, and the weighted-average units used to compute diluted net (loss) income per common unit (in thousands, except per unit data):

	Year ended December 31,		
	2010	2009	2008
Net income (loss) attributable to the Partnership	$ 467	$(118,668)	$208,073
Less: Income allocable to phantom units	1,308	1,518	3,037
(Loss) income available for common unitholders	$ (841)	$(120,186)	$205,036
Weighted average common units outstanding—basic	70,128	60,957	51,013
Effect of dilutive instruments(1)	—	—	3
Weighted average common units outstanding—diluted	70,128	60,957	51,016
Net (loss) income attributable to the Partnership's common unitholders per common unit			
Basic	$ (0.01)	$ (1.97)	$ 4.02
Diluted	$ (0.01)	$ (1.97)	$ 4.02

(1) For the year ended December 31, 2010, dilutive instruments include TUR Phantom Units and are based on the number of units, if any, that would be issuable at the end of the respective reporting

24. (Loss) Earnings Per Common Unit (Continued)

period, assuming that date was the end of the contingency period. For the year ended December 31, 2010, 195 units were excluded from the calculation of diluted units because the impact was anti-dilutive. See Note 21 for further discussion of TUR Phantom Units. For the year ended December 31, 2008, dilutive instruments include MarkWest Hydrocarbon stock options outstanding prior to the Merger.

25. Segment Information

The Partnership's chief operating decision maker is the chief executive officer ("CEO"). The CEO reviews the Partnership's discrete financial information on a geographic and operational basis, as the products and services are closely related within each geographic region and business operation. Accordingly, the CEO makes operating decisions, assesses financial performance and allocates resources on a geographical basis. The Partnership has four segments: Southwest, Northeast, Liberty and Gulf Coast. The Southwest segment provides gathering, processing, transportation, and storage services. The Northeast segment provides gathering, processing, transportation, fractionation and storage services. The Liberty segment provides gathering, processing, transportation, fractionation and storage services. The Liberty segment was a new segment beginning in 2009 and consists primarily of the operations in the Marcellus Shale region of western Pennsylvania and northern West Virginia. The Gulf Coast segment provides processing, transportation, fractionation and storage services.

The Partnership prepares segment information in accordance with GAAP. Certain items below *Income (loss) from operations* in the accompanying Consolidated Statements of Operations, certain compensation expense, certain other non-cash items and any gains (losses) from derivative instruments are not allocated to individual segments. Management does not consider these items allocable to or controllable by any individual segment and therefore excludes these items when evaluating segment performance. The 2010 and 2009 segment results are also adjusted to exclude the portion of operating income attributable to the non-controlling interests.

25. Segment Information (Continued)

The tables below present information about operating income and capital expenditures for the reported segments for the years ended December 31, 2010, 2009 and 2008 (in thousands).

Year ended December 31, 2010:

	Southwest	Northeast	Liberty	Gulf Coast	Total
Revenue	$665,768	$384,724	$105,911	$85,160	$1,241,563
Purchased product costs	308,960	252,827	16,840	—	578,627
Net operating margin	356,808	131,897	89,071	85,160	662,936
Facility expenses	81,772	19,513	24,028	33,337	158,650
Portion of operating income attributable to non-controlling interests	6,440	—	26,126	—	32,566
Operating income before items not allocated to segments	$268,596	$112,384	$ 38,917	$51,823	$ 471,720
Capital expenditures	$114,109	$ 2,179	$332,793	$ 3,947	$ 453,028
Capital expenditures not allocated to segments					5,640
Total capital expenditures					$ 458,668

Year ended December 31, 2009:

	Southwest	Northeast	Liberty	Gulf Coast	Total
Revenue	$492,369	$260,529	$ 47,968	$57,769	$858,635
Purchased product costs	221,021	175,326	12,479	—	408,826
Net operating margin	271,348	85,203	35,489	57,769	449,809
Facility expenses	73,621	20,339	16,268	16,094	126,322
Portion of operating income attributable to non-controlling interests	2,613	—	6,637	—	9,250
Operating income before items not allocated to segments	$195,114	$ 64,864	$ 12,584	$41,675	$314,237
Capital expenditures	$236,705	$ 21,538	$181,142	$40,606	$479,991
Capital expenditures not allocated to segments					6,632
Total capital expenditures					$486,623

25. Segment Information (Continued)

Year ended December 31, 2008:

	Southwest	Northeast	Liberty	Gulf Coast	Total
Revenue	$652,365	$313,921	$ 2,334	$92,042	$1,060,662
Purchased product costs	387,516	228,386	—	—	615,902
Net operating margin	264,849	85,535	2,334	92,042	444,760
Facility expenses	62,369	20,869	2,006	17,368	102,612
Operating income before items not allocated to segments	$202,480	$ 64,666	$ 328	$74,674	$ 342,148
Capital expenditures	$354,457	$ 40,443	$109,104	$66,065	$ 570,069
Capital expenditures not allocated to segments					5,229
Total capital expenditures					$ 575,298

25. Segment Information (Continued)

The following is a reconciliation of segment revenue to total revenue and operating income before items not allocated to segments to income before provision for income tax for the three years ended December 31, 2010, 2009 and 2008 (in thousands):

	Year ended December 31,		
	2010	2009	2008
Total segment revenue	$1,241,563	$ 858,635	$1,060,662
Derivative (loss) gain not allocated to segments	(53,932)	(120,352)	277,828
Total revenue	$1,187,631	$ 738,283	$1,338,490
Operating income before items not allocated to segments	$ 471,720	$ 314,237	$ 342,148
Portion of operating income attributable to non-controlling interests	32,566	9,250	—
Derivative (loss) gain not allocated to segments	(80,350)	(188,862)	254,813
Compensation expense included in facility expenses not allocated to segments	(1,890)	(1,032)	(1,070)
Facility expenses adjustments	9,091	377	—
Selling, general and administrative expenses	(75,258)	(63,728)	(68,975)
Depreciation	(123,198)	(95,537)	(67,480)
Amortization of intangible assets	(40,833)	(40,831)	(38,483)
Loss on disposal of property, plant and equipment	(3,149)	(1,677)	(178)
Accretion of asset retirement obligations	(237)	(198)	(129)
Impairment of goodwill and long-lived assets	—	(5,855)	(36,351)
Income (loss) from operations	188,462	(73,856)	384,295
Earnings from unconsolidated affiliates	1,562	3,505	90
Impairment of unconsolidated affiliate	—	—	(41,449)
Gain on sale of unconsolidated affiliate	—	6,801	—
Interest income	1,670	349	3,769
Interest expense	(103,873)	(87,419)	(64,563)
Amortization of deferred financing costs and discount (a component of interest expense)	(10,264)	(9,718)	(8,299)
Derivative gain related to interest expense	1,871	2,509	—
Loss on redemption of debt	(46,326)	—	—
Miscellaneous income (expense), net	1,189	2,459	(241)
Income (loss) before provision for income tax	$ 34,291	$(155,370)	$ 273,602

25. Segment Information (Continued)

The tables below present information about segment assets as of December 31, 2010 and 2009 (in thousands):

	December 31, 2010	December 31, 2009
Southwest	$1,646,607	$1,637,749
Northeast	244,219	249,804
Liberty	743,943	373,127
Gulf Coast	573,456	587,830
Total segment assets	3,208,225	2,848,510
Assets not allocated to segments:		
Certain cash and cash equivalents	49,776	73,184
Fair value of derivatives	4,762	24,631
Investment in unconsolidated affiliate	28,688	29,633
Other(1)	41,911	38,779
Total assets	$3,333,362	$3,014,737

(1) As of December 31, 2010, includes corporate fixed assets, deferred financing costs, income tax receivable, receivables and other corporate assets not allocated to segments. As of December 31, 2009, includes corporate fixed assets, deferred financing costs, income tax receivable and other corporate assets not allocated to segments.

26. Supplemental Condensed Consolidating Financial Information

MarkWest Energy Partners has no significant operations independent of its subsidiaries. As of December 31, 2010, the Partnership's obligations under the outstanding Senior Notes (see Note 17) were fully and unconditionally guaranteed, jointly and severally, by all of its wholly-owned subsidiaries. Separate financial statements for each of the Partnership's guarantor subsidiaries are not provided because such information would not be material to its investors or lenders. As of February 2009, following the closing of the joint venture with M&R, and May 2009, following the closing of the joint venture with ArcLight (see Note 4), MarkWest Liberty Midstream and MarkWest Pioneer, together with certain of the Partnership's other subsidiaries that do not guarantee the outstanding Senior Notes, have significant assets and operations in aggregate. For the purpose of the following financial information, the Partnership's investments in its subsidiaries and the guarantor subsidiaries' investments in their subsidiaries are presented 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. The operations, cash flows, and financial position of the co-issuer, MarkWest Energy Finance Corporation, are not material and therefore have been included with the Parent's financial information. Comparative financial statements for the year ended December 31, 2008 have not been provided because the non-guarantor subsidiaries as of December 31, 2008 were minor subsidiaries individually and in the aggregate. Condensed consolidating financial information for MarkWest Energy Partners and its combined guarantor and combined non-guarantor

26. Supplemental Condensed Consolidating Financial Information (Continued)

subsidiaries as of December 31, 2010 and 2009 and for the years ended December 31, 2010 and 2009 is as follows (in thousands):

Condensed Consolidating Balance Sheets

	As of December 31, 2010				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ 63,850	$ 3,600	$ —	$ 67,450
Receivables and other current assets	1,708	172,209	52,834	—	226,751
Intercompany receivables	1,440,302	1,099	7,635	(1,449,036)	—
Fair value of derivative instruments	—	4,345	—	—	4,345
Total current assets	1,442,010	241,503	64,069	(1,449,036)	298,546
Total property, plant and equipment, net	4,623	1,512,763	812,898	(11,260)	2,319,024
Other long-term assets:					
Restricted cash	—	—	28,001	—	28,001
Investment in unconsolidated affiliate	—	28,688	—	—	28,688
Investment in consolidated affiliates	716,673	368,864	—	(1,085,537)	—
Intangibles, net of accumulated amortization	—	613,000	578	—	613,578
Fair value of derivative instruments	—	417	—	—	417
Intercompany notes receivable	197,710	—	—	(197,710)	—
Other long-term assets	32,587	12,139	382	—	45,108
Total assets	$2,393,603	$2,777,374	$905,928	$(2,743,543)	$3,333,362
LIABILITIES AND EQUITY					
Current liabilities:					
Intercompany payables	$ 672	$1,447,799	$ 565	$(1,449,036)	$ —
Fair value of derivative instruments	—	65,489	—	—	65,489
Other current liabilities	31,882	173,667	70,804	—	276,353
Total current liabilities	32,554	1,686,955	71,369	(1,449,036)	341,842
Deferred income taxes	2,533	7,894	—	—	10,427
Intercompany notes payable	—	197,710	—	(197,710)	—
Fair value of derivative instruments	—	66,290	—	—	66,290
Long-term debt, net of discounts	1,273,434	—	—	—	1,273,434
Other long-term liabilities	3,319	101,852	178	—	105,349
Equity:					
MarkWest Energy Partners, L.P. partners' capital	1,081,763	716,673	834,381	(1,562,314)	1,070,503
Non-controlling interest in consolidated subsidiaries	—	—	—	465,517	465,517
Total equity	1,081,763	716,673	834,381	(1,096,797)	1,536,020
Total liabilities and equity	$2,393,603	$2,777,374	$905,928	$(2,743,543)	$3,333,362

26. Supplemental Condensed Consolidating Financial Information (Continued)

	As of December 31, 2009				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ 74,448	$ 23,304	$ —	$ 97,752
Receivables and other current assets	870	165,421	26,655	—	192,946
Intercompany receivables	1,543,169	2,091	88	(1,545,348)	—
Fair value of derivative instruments	246	8,575	—	—	8,821
Total current assets	1,544,285	250,535	50,047	(1,545,348)	299,519
Total property, plant and equipment, net	3,307	1,499,233	484,788	(5,684)	1,981,644
Other long-term assets:					
Investment in unconsolidated affiliate	—	29,633	—	—	29,633
Investment in consolidated affiliates	529,846	203,895	—	(733,741)	—
Intangibles, net of accumulated amortization	—	653,797	614	—	654,411
Fair value of derivative instruments	—	15,810	—	—	15,810
Intercompany notes receivable	210,060	—	—	(210,060)	—
Other long-term assets	20,538	13,182	—	—	33,720
Total assets	$2,308,036	$2,666,085	$535,449	$(2,494,833)	$3,014,737
LIABILITIES AND EQUITY					
Current liabilities:					
Intercompany payables	$ 1,195	$1,543,257	$ 896	$(1,545,348)	$ —
Fair value of derivative instruments	—	60,464	—	—	60,464
Other current liabilities	28,673	149,319	47,527	—	225,519
Total current liabilities	29,868	1,753,040	48,423	(1,545,348)	285,983
Deferred income taxes	2,694	8,340	—	—	11,034
Intercompany notes payable	—	210,060	—	(210,060)	—
Fair value of derivative instruments	—	62,519	—	—	62,519
Long-term debt, net of discounts	1,170,072	—	—	—	1,170,072
Other long-term liabilities	3,064	102,280	392	—	105,736
Equity:					
MarkWest Energy Partners, L.P. partners' capital	1,102,338	529,846	486,634	(1,022,164)	1,096,654
Non-controlling interest in consolidated subsidiaries	—	—	—	282,739	282,739
Total equity	1,102,338	529,846	486,634	(739,425)	1,379,393
Total liabilities and equity	$2,308,036	$2,666,085	$535,449	$(2,494,833)	$3,014,737

26. Supplemental Condensed Consolidating Financial Information (Continued)

Condensed Consolidating Statements of Operations

	Year ended December 31, 2010				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue	$ —	$1,063,621	$124,010	$ —	$1,187,631
Operating expenses:					
Purchased product costs	—	589,403	16,937	—	606,340
Facility expenses	—	122,240	28,566	(652)	150,154
Selling, general and administrative expenses	46,549	27,339	6,317	(4,947)	75,258
Depreciation and amortization	594	136,781	27,054	(398)	164,031
Other operating expenses	753	2,342	291	—	3,386
Total operating expenses	47,896	878,105	79,165	(5,997)	999,169
(Loss) income from operations	(47,896)	185,516	44,845	5,997	188,462
Earnings from consolidated affiliates	183,557	15,963	—	(199,520)	—
Loss on redemption of debt	(46,326)	—	—	—	(46,326)
Other (expense) income, net	(82,000)	(16,032)	1,753	(11,566)	(107,845)
Income before provision for income tax	7,335	185,447	46,598	(205,089)	34,291
Provision for income tax expense	1,299	1,890	—	—	3,189
Net income	6,036	183,557	46,598	(205,089)	31,102
Net income attributable to non-controlling interest	—	—	—	(30,635)	(30,635)
Net income attributable to the Partnership	$ 6,036	$ 183,557	$ 46,598	$(235,724)	$ 467

26. Supplemental Condensed Consolidating Financial Information (Continued)

	Year ended December 31, 2009				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue	$ —	$686,340	$51,943	$ —	$ 738,283
Operating expenses:					
Purchased product costs	—	465,152	12,557	—	477,709
Facility expenses	—	110,147	16,834	(377)	126,604
Selling, general and administrative expenses	46,317	17,990	2,878	(3,457)	63,728
Depreciation and amortization	559	124,976	10,984	(151)	136,368
Other operating expenses	(161)	2,019	17	—	1,875
Impairment of long-lived assets	—	—	5,855	—	5,855
Total operating expenses	46,715	720,284	49,125	(3,985)	812,139
(Loss) income from operations	(46,715)	(33,944)	2,818	3,985	(73,856)
Earnings from consolidated affiliates	2,243	1,501	—	(3,744)	—
Gain on sale of unconsolidated affiliate	—	6,801	—	—	6,801
Other (expense) income, net	(69,951)	(12,692)	3,997	(9,669)	(88,315)
(Loss) income before provision for income tax	(114,423)	(38,334)	6,815	(9,428)	(155,370)
Provision for income tax benefit	(1,439)	(40,577)	—	—	(42,016)
Net (loss) income	(112,984)	2,243	6,815	(9,428)	(113,354)
Net income attributable to non-controlling interest	—	—	—	(5,314)	(5,314)
Net (loss) income attributable to the Partnership	$(112,984)	$ 2,243	$ 6,815	$(14,742)	$(118,668)

26. Supplemental Condensed Consolidating Financial Information (Continued)

Condensed Consolidating Statements of Cash Flows

	Year ended December 31, 2010				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net cash (used in) provided by operating activities	$(102,042)	$ 373,483	$ 46,852	$ (5,965)	$ 312,328
Cash flows from investing activities:					
Restricted cash	—	—	(28,001)	—	(28,001)
Capital expenditures	(1,924)	(123,005)	(347,231)	13,492	(458,668)
Equity investments	(44,346)	(171,252)	—	215,598	—
Distributions from consolidated affiliates	41,167	22,246	—	(63,413)	—
Collection of intercompany notes, net	12,350	—	—	(12,350)	—
Proceeds from disposal of property, plant and equipment	—	733	7,527	(7,527)	733
Net cash flows provided by (used in) investing activities	7,247	(271,278)	(367,705)	145,800	(485,936)
Cash flows from financing activities:					
Proceeds from revolving credit facility	494,404	—	—	—	494,404
Payments of revolving credit facility	(553,704)	—	—	—	(553,704)
Proceeds from long-term debt	500,000	—	—	—	500,000
Payments of long-term debt	(375,000)	—	—	—	(375,000)
Payments of premiums on redemption of long-term debt	(9,732)	—	—	—	(9,732)
Payments of intercompany notes, net	—	(12,350)	—	12,350	—
Payments for debt issuance costs, deferred financing costs and registration costs	(20,912)	—	—	—	(20,912)
Contributions from parent, net	—	44,346	—	(44,346)	—
Contributions to joint ventures, net	—	—	329,545	(171,252)	158,293
Payments of SMR Liability	—	(1,354)	—	—	(1,354)
Proceeds from public offering, net	142,255	—	—	—	142,255
Share-based payment activity	(3,834)	98	—	—	(3,736)
Payment of distributions	(181,058)	(41,167)	(28,396)	63,413	(187,208)
Intercompany advances, net	102,376	(102,376)	—	—	—
Net cash flows provided by (used in) financing activities	94,795	(112,803)	301,149	(139,835)	143,306
Net decrease in cash	—	(10,598)	(19,704)	—	(30,302)
Cash and cash equivalents at beginning of year	—	74,448	23,304	—	97,752
Cash and cash equivalents at end of period	$ —	$ 63,850	$ 3,600	$ —	$ 67,450

26. Supplemental Condensed Consolidating Financial Information (Continued)

	Year ended December 31, 2009				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net cash (used in) provided by operating activities	$ (98,853)	$ 322,540	$ 5,249	$ (5,835)	$ 223,101
Cash flows from investing activities:					
Capital expenditures	(1,688)	(209,485)	(281,285)	5,835	(486,623)
Equity investments	(52,358)	(127,806)	—	179,759	(405)
Distributions from consolidated affiliates	13,984	31,227	—	(45,211)	—
Collection of intercompany notes, net	21,340	—	—	(21,340)	—
Proceeds from sale of unconsolidated affiliate	—	25,000	—	—	25,000
Proceeds from disposal of property, plant and equipment	—	275	—	—	275
Proceeds from sale of equity interest in consolidated subsidiary	—	62,500	—	(62,500)	—
Net cash flows used in investing activities	(18,722)	(218,289)	(281,285)	56,543	(461,753)
Cash flows from financing activities:					
Proceeds from revolving credit facility	725,200	—	—	—	725,200
Payments of revolving credit facility	(850,600)	—	—	—	(850,600)
Proceeds from long-term debt	117,000	—	—	—	117,000
Payments of intercompany notes, net	—	(21,340)	—	21,340	—
Payments for debt issuance costs, deferred financing costs and registration costs	(8,054)	(500)	—	—	(8,554)
Contributions from parent, net	—	52,358	—	(52,358)	—
Contributions to joint ventures, net	(5,464)	—	327,401	(127,401)	194,536
Proceeds from sale of equity interest in joint venture, net	(1,846)	—	—	62,500	60,654
Proceeds from SMR Transaction	—	73,129	—	—	73,129
Proceeds from public offerings, net	178,565	—	—	—	178,565
Share-based payment activity	(1,385)	—	—	—	(1,385)
Payment of distributions	(155,307)	(13,984)	(31,382)	45,211	(155,462)
Intercompany advances, net	119,466	(119,466)	—	—	—
Net cash flows provided by (used in) financing activities	117,575	(29,803)	296,019	(50,708)	333,083
Net increase in cash	—	74,448	19,983	—	94,431
Cash and cash equivalents at beginning of year	—	—	3,321	—	3,321
Cash and cash equivalents at end of period	$ —	$ 74,448	$ 23,304	$ —	$ 97,752

27. Supplemental Cash Flow Information

The following table provides information regarding supplemental cash flow information (in thousands):

	Year ended December 31, 2010	2009	2008
Supplemental disclosures of cash flow information:			
Cash paid for interest, net of amounts capitalized	$101,459	$85,817	$ 55,428
Cash paid for income taxes, net of refunds	8,683	4,609	19,243
Supplemental schedule of non-cash investing and financing activities:			
Accrued property, plant and equipment	$ 65,908	$60,738	$ 51,060
Interest capitalized on construction in progress	2,766	12,228	9,486
Issuance of common units for vesting of share-based payment awards	7,238	9,402	2,492
Merger step-up of fair value	—	—	605,100

28. Valuation and Qualifying Accounts

Activity in the allowance for doubtful accounts is as follows (in thousands):

	Year ended December 31, 2010	2009	2008
Balance at beginning of period	$ 162	$175	$194
Charged to costs and expenses	134	12	(15)
Other charges(1)	(134)	(25)	(4)
Balance at end of period	$ 162	$162	$175

(1) Bad debts written off (net of recoveries).

Activity in the deferred tax assets valuation allowance is as follows (in thousands):

	Year ended December 31, 2010	2009	2008
Balance at beginning of period	$1,688	$ 30	$ 53
Charged to costs and expenses	(652)	1,667	—
Other charges	—	(9)	(23)
Balance at end of period	$1,036	$1,688	$ 30

29. Quarterly Results of Operations (Unaudited)

The following summarizes the Partnership's quarterly results of operations for 2010 and 2009 (in thousands, except per unit data):

	Three months ended			
	March 31	June 30	September 30	December 31(1)
2010				
Total revenue	$308,379	$323,850	$255,411	$299,991
Income from operations	53,573	109,071	646	25,172
Net income (loss)	26,004	66,968	(18,676)	(43,194)
Net income (loss) attributable to the Partnership	21,510	60,217	(27,151)	(54,109)
Net income (loss) attributable to the Partnership's common unitholders per common unit(2):				
Basic	$ 0.32	$ 0.84	$ (0.39)	$ (0.76)
Diluted	$ 0.32	$ 0.84	$ (0.39)	$ (0.76)

	Three months ended			
	March 31	June 30	September 30	December 31
2009				
Total revenue	$191,671	$101,765	$217,691	$227,156
(Loss) income from operations	(19,108)	(67,450)	35,654	(22,952)
Net (loss) income	(29,669)	(69,196)	11,904	(26,393)
Net (loss) income attributable to the Partnership	(29,649)	(67,506)	8,280	(29,793)
Net (loss) income attributable to the Partnership's common unitholders per common unit(2):				
Basic	$ (0.53)	$ (1.18)	$ 0.13	$ (0.46)
Diluted	$ (0.53)	$ (1.18)	$ 0.13	$ (0.46)

(1) During the fourth quarter of 2010, the Partnership recorded a loss on redemption of debt of approximately $46.3 million related to the redemption of $375 million of 2014 Senior Notes. See Note 17 for further details.

(2) Basic and diluted net (loss) income per unit are computed independently for each of the quarters presented; therefore, the sum of the quarterly earnings per unit may not equal the total computed for the year.

30. Subsequent Events

Langley Acquisition

On January 3, 2011, MarkWest Energy Appalachia, L.L.C. ("MarkWest Appalachia"), a wholly-owned subsidiary of the Partnership, entered into a Purchase and Sale Agreement (the "Agreement") with EQT Gathering, LLC, a subsidiary of EQT Corporation (together with all of its affiliates, "EQT"). Pursuant to the Agreement, MarkWest Appalachia agreed to acquire gas processing facilities located near Langley and Maytown, Kentucky, consisting of a cryogenic natural gas processing plant with a capacity of approximately 100 MMcf/d and a refrigeration processing plant with a capacity of approximately 75 MMcf/d (together, the "Processing Facilities"), a partially constructed natural gas

30. Subsequent Events (Continued)

liquids pipeline (the "Ranger Pipeline") extending through parts of Kentucky and West Virginia, and certain other related assets, for a purchase price of approximately $230 million, subject to customary purchase price adjustments. We refer to this acquisition as the Langley Acquisition. In connection with the Langley Acquisition, MarkWest Appalachia will complete the construction of the Ranger Pipeline to connect the Processing Facilities to MarkWest Appalachia's existing natural gas liquids pipeline that transports natural gas liquids to MarkWest Appalachia's Siloam fractionation facility in South Shore, Kentucky. The transaction closed on February 1, 2011. The Partnership has not completed its valuation and purchase price allocation of the acquired assets and liabilities.

Concurrently with the closing of the Langley Acquisition, MarkWest Appalachia and EQT, entered into a long-term gas processing agreement, pursuant to which MarkWest Appalachia will process certain natural gas owned or controlled by EQT at the Processing Facilities. Under the terms of the gas processing agreement, MarkWest Appalachia will also install an additional cryogenic natural gas processing plant with a capacity of at least 60 MMcf/d in 2012. MarkWest Appalachia and EQT also entered into a long-term natural gas liquids exchange and marketing agreement, which replaced an existing transportation, fractionation and marketing agreement between MarkWest Appalachia and EQT. Pursuant to the natural gas liquids exchange and marketing agreement, natural gas liquids extracted from EQT's gas at the Processing Facilities will be exchanged for fractionated natural gas liquid products at MarkWest Appalachia's Siloam fractionation plant, and MarkWest Appalachia will market those fractionated products on behalf of EQT.

Embedded derivative extension

The Partnership has a commodity contract with a producer in the Appalachia region that creates a floor on the frac spread for gas purchases of 9,000 Dth/d. The commodity contract is a component of a broader regional arrangement that also includes a keep-whole processing agreement. As of December 31, 2009, the producer had exercised its right to extend this contract and the related processing agreement through the first quarter of 2015. This contract is accounted for as an embedded derivative and is recorded at fair value and the changes in fair value are reflected in earnings. In February 2011, the Partnership executed agreements with the producer to extend the commodity contract and the related processing agreement through 2022.

Equity Offering

On January 14, 2011, the Partnership completed a public offering of approximately 3.45 million newly issued common units representing limited partner interests, which includes the full exercise of the underwriters' over-allotment option, at a price of $41.20 per common unit. Net proceeds of approximately $138 million were used to partially fund the Partnership's ongoing capital expenditure program, including a portion of the costs associated with acquisition of assets from EQT as discussed above.

Senior Notes Offering and Tender Offers

On February 24, 2011, the Partnership closed a public offering of $300 million in aggregate principal amount of 6.5% senior unsecured notes due 2021 ("2021 Senior Notes"). The 2021 Senior Notes mature on August 15, 2021, and interest is payable semi-annually in arrears on February 15 and August 15, commencing August 15, 2011. The Partnership received net proceeds of approximately

30. Subsequent Events (Continued)

$296 million after deducting the underwriting fees and other third-party expenses associated with the offering. The Partnership used the net proceeds from this offering to fund the concurrent repurchase of approximately $272.2 million in aggregate principal amount of the Partnership's 2016 Senior Notes, representing approximately 99% of the outstanding 2016 Senior Notes, pursuant to the Partnership's tender offer for any and all of the outstanding 2016 Senior Notes. The tender offer for the 2016 Senior Notes will expire on March 9, 2011. Assuming no additional 2016 Senior Notes are tendered for repurchase prior to the expiration of the tender offer, the Partnership will record a pre-tax loss on redemption of debt of approximately $21 million in the first quarter of 2011, which will consist of approximately $1 million for the non-cash write off of the unamortized discount and deferred finance costs and approximately $20 million for the payment of the related tender premiums and third-party expenses.

On February 9, 2011, the Partnership commenced a tender offer for up to $125 million aggregate principal amount ("Tender Cap") of its outstanding 2018 Senior Notes. On February 23, 2011, the Tender Cap was increased to $170 million and as of such date, holders of the 2018 Senior Notes had tendered approximately $165.5 million in aggregate principal amount of the outstanding 2018 Senior Notes for repurchase at various bid prices within the acceptable range of $1,090.00 to $1,115.00 per $1,000 principal amount. The tender offer for the 2018 Senior Notes expires on March 9, 2011. Assuming the Partnership completes the repurchase of the $165.5 million in aggregate principal amount of 2018 Senior Notes tendered for repurchase as of February 23, 2011 and no additional 2018 Senior Notes are tendered for repurchase prior to the expiration of the tender offer for the 2018 Senior Notes, the Partnership will record a pre-tax loss on redemption of debt of approximately $22 million in the first quarter of 2011, which will consist of approximately $3 million for the non-cash write off of the unamortized discount and deferred finance costs and approximately $19 million for the payment of the related tender premiums and third-party expenses.

ITEM 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

ITEM 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

An evaluation was performed under the supervision and with the participation of the Partnership's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rule 13a-15(e) of the 1934 Act, as of December 31, 2010. Based on this evaluation, the Partnership's management, including our Chief Executive Officer and Chief Financial Officer, concluded that as of December 31, 2010, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the 1934 Act is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms and to provide reasonable assurance that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

Management's Report on Internal Control Over Financial Reporting

Management of the Partnership is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 13a-15(f) of the 1934 Act. Management has assessed the effectiveness of our internal control over financial reporting as of December 31, 2010 based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. As a result of this assessment, management concluded that, as of December 31, 2010, our internal control over financial reporting was effective in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Limitations on Controls

Our disclosure controls and procedures and internal control over financial reporting are designed to provide reasonable assurance of achieving their objectives as specified above. Management does not expect, however, that our disclosure controls and procedures or our internal control over financial reporting will prevent or detect all error and fraud. Any control system, no matter how well designed and operated, is based upon certain assumptions and can provide only reasonable, not absolute, assurance that its objectives will be met. Further, no evaluation of controls can provide absolute assurance that misstatements due to error or fraud will not occur or that all control issues and instances of fraud, if any, within the Partnership have been detected.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2010 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Deloitte & Touche has independently assessed the effectiveness of our internal control over financial reporting and its report is included below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
MarkWest Energy GP, L.L.C.
Denver, Colorado

We have audited the internal control over financial reporting of MarkWest Energy Partners, L.P., and subsidiaries (the "Partnership") as of December 31, 2010 based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2010 of the Partnership and our report dated February 28, 2011 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 28, 2011

ITEM 9B. Other Information

None.

PART III

ITEM 10. Directors, Executive Officers and Corporate Governance

Information required to be set forth in Item 10. Directors, Executive Officers and Corporate Governance, has been omitted and will be incorporated herein by reference, when filed, to our Proxy Statement for our 2011 Annual Meeting of Unitholders expected to be filed no later than May 2, 2011.

ITEM 11. Executive Compensation

Information required to be set forth in Item 11. Executive Compensation, has been omitted and will be incorporated herein by reference, when filed, to our Proxy Statement for our 2011 Annual Meeting of Unitholders expected to be filed no later than May 2, 2011.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

Information required to be set forth in Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters, has been omitted and will be incorporated herein by reference, when filed, to our Proxy Statement for our 2011 Annual Meeting of Unitholders expected to be filed no later than May 2, 2011.

ITEM 13. Certain Relationships and Related Transactions, and Director Independence

Information required to be set forth in Item 13. Certain Relationships and Related Transactions, and Director Independence, has been omitted and will be incorporated herein by reference, when filed, to our Proxy Statement for our 2011 Annual Meeting of Unitholders expected to be filed no later than May 2, 2011.

ITEM 14. Principal Accountant Fees and Services

Information required to be set forth in Item 14. Principal Accountant Fees and Services, has been omitted and will be incorporated herein by reference, when filed, to our Proxy Statement for our 2011 Annual Meeting of Unitholders expected to be filed no later than May 2, 2011.

PART IV

ITEM 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as part of this report:

(1) Financial Statements

You should read the Index to Consolidated Financial Statements included in Item 8 of this Form 10-K for a list of all financial statements filed as part of this report, which is incorporated herein by reference.

(2) Financial Statement Schedules

All schedules have been omitted because they are not required or because the required information is contained in the financial statements or notes thereto.

(3) Exhibits

Exhibit Number	Description
2.1(9)	Agreement and Plan of Redemption and Merger dated September 5, 2007 by and among MarkWest Hydrocarbon, Inc., MarkWest Energy Partners, L.P. and MWEP, L.L.C.
3.1(1)	Certificate of Limited Partnership of MarkWest Energy Partners, L.P.
3.2(1)	Certificate of Formation of MarkWest Energy Operating Company, L.L.C.
3.3(2)	Amended and Restated Limited Liability Company Agreement of MarkWest Energy Operating Company, L.L.C., dated as of May 24, 2002.
3.4(1)	Certificate of Formation of MarkWest Energy GP, L.L.C.
3.5(2)	Amended and Restated Limited Liability Company Agreement of MarkWest Energy GP, L.L.C., dated as of May 24, 2002.
3.6(14)	Third Amended and Restated Agreement of Limited Partnership of MarkWest Energy Partners, L.P., dated as of February 21, 2008.
3.7(24)	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement MarkWest Energy GP, L.L.C., dated as of December 31, 2004.
3.8(24)	Amendment No. 2 to Amended and Restated Limited Liability Company Agreement MarkWest Energy GP, L.L.C., dated as of January 19, 2005.
3.9(24)	Amendment No. 3 to Amended and Restated Limited Liability Company Agreement MarkWest Energy GP, L.L.C., dated as of February 21, 2008.
3.10(24)	Amendment No. 4 to Amended and Restated Limited Liability Company Agreement MarkWest Energy GP, L.L.C., dated as of March 31, 2008.
4.1(5)	Registration Rights Agreement dated as of July 6, 2006 among MarkWest Energy Partners, L.P., with MarkWest Energy Finance Corporation as the Issuers, the Guarantors named therein, and each of RBC Capital Markets Corporation, J.P. Morgan Securities Inc., Wachovia Capital Markets, LLC, A.G. Edwards & Sons, Inc., Credit Suisse Securities (USA) LLC, Fortis Securities LLC, Mizuho International plc, Piper Jaffray & Co. and SG Americas Securities, LLC collectively as Initial Purchasers.
4.2(5)	Indenture dated as of July 6, 2006, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
4.3(5)	Form of 8.5% Series A and Series B Senior Notes due 2016 with attached notation of Guarantees (incorporated by Reference to Exhibits A and D of Exhibit 4.2 hereto).
4.4(20)	First Supplemental Indenture, dated as of March 6, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
4.5(20)	Second Supplemental Indenture, dated as of April 25, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
4.6(20)	Third Supplemental Indenture, dated as of August 4, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.

Exhibit Number	Description
4.7(20)	Fourth Supplemental Indenture, dated as of September 15, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
4.8(30)	Fifth Supplemental Indenture, dated as of February 24, 2011, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
4.9(6)	Registration Rights Agreement dated as of October 20, 2006 among MarkWest Energy Partners, L.P., with MarkWest Energy Finance Corporation as the Issuers, the Guarantors named therein, and RBC Capital Markets as the Initial Purchaser.
4.10(14)	Registration Rights Agreement dated as of February 21, 2008 by and among MarkWest Energy Partners, L.P., John M. Fox and MWHC Holding, Inc.
4.11(14)	Registration Rights Agreement dated as of February 21, 2008 by and among MarkWest Energy Partners, L.P. and the holders named therein.
4.12(16)	Indenture dated as of April 15, 2008 among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the several guarantors named therein, and Wells Fargo Bank, N.A., as trustee.
4.13(16)	Form of 8¾% Series A and Series B Senior Notes due 2018 with attached notation of Guarantees (incorporated by reference to Exhibits A and D of Exhibit 4.12 hereto).
4.14(16)	Registration Rights Agreement dated as of April 15, 2008 among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, and the several guarantors named therein, and J.P. Morgan Securities Inc., RBC Capital Markets Corporation, Wachovia Capital Markets, LLC, Banc of America Securities LLC, Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., Fortis Securities LLC and SunTrust Robinson Humphrey, Inc.
4.15(17)	Registration Rights Agreement dated as of May 1, 2008 among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, and the several guarantors named therein, and J.P. Morgan Securities Inc., RBC Capital Markets Corporation, Wachovia Capital Markets, LLC, Banc of America Securities LLC, Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., Fortis Securities LLC and SunTrust Robinson Humphrey, Inc.
4.16(20)	First Supplemental Indenture, dated as of April 25, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
4.17(20)	Second Supplemental Indenture, dated as of August 4, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
4.18(20)	Third Supplemental Indenture, dated as of September 15, 2008, among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee.
4.19(21)	Indenture Release of Subsidiary Guarantor dated as of May 1, 2009, among MarkWest Energy Partners, L.P., and Wells Fargo Bank, N.A.
4.20(22)	Indenture Release of Subsidiary Guarantor dated as of October 31, 2009, among MarkWest Energy Partners, L.P. and Wells Fargo Bank, N.A.

Exhibit Number	Description
4.21(26)	Indenture, dated as of November 2, 2010, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee.
4.22(26)	First Supplemental Indenture, dated as of November 2, 2010, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee.
4.23(26)	Form of 6¾% Senior Notes due 2020 with attached notation of Guarantees (incorporated by reference to Exhibits A and B of Exhibit 4.22 hereto).
4.24(30)	Second Supplemental Indenture, dated as of February 24, 2011, by and among MarkWest Energy Partners, L.P., MarkWest Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as trustee.
4.25(30)	Form of 8.5% Senior Notes due 2021 with attached notation of Guarantees (incorporated by reference to Exhibits A and B of Exhibit 4.24 hereto).
10.1(28)	Amended and Restated Revolving Credit Agreement dated as of July 1, 2010 among MarkWest Energy Partners, L.P., Wells Fargo Bank, National Association, as successor Administrative Agent, Issuing Bank and Swingline Linder, Royal Bank of Canada, as prior administrative agent, RBC Capital Markets, as Syndication Agent, BNP Paribas, Morgan Stanley Bank and U.S. Bank National Association, as Documentation Agents, and the lenders party thereto.
10.2(29)	Joinder Agreement dated as of July 29, 2010 among MarkWest Energy Partners, L.P., Wells Fargo Bank, National Association, individually and as Administrative Agent, Issuing Bank and Swingline Lender and Goldman Sachs Bank USA.
10.3(2)	Contribution, Conveyance and Assumption Agreement dated as of May 24, 2002, by and among MarkWest Energy Partners, L.P.; MarkWest Energy Operating Company, L.L.C.; MarkWest Energy GP, L.L.C.; MarkWest Michigan, Inc.; MarkWest Energy Appalachia, L.L.C.; West Shore Processing Company, L.L.C.; Basin Pipeline, L.L.C.; and MarkWest Hydrocarbon, Inc.
10.4(2)	Omnibus Agreement dated of May 24, 2002, among MarkWest Hydrocarbon, Inc.; MarkWest Energy GP, L.L.C.; MarkWest Energy Partners, L.P.; and MarkWest Energy Operating Company, L.L.C.
10.5(2)+	Fractionation, Storage and Loading Agreement dated as of May 24, 2002, between MarkWest Energy Appalachia, L.L.C. and MarkWest Hydrocarbon, Inc.
10.6(2)+	Gas Processing Agreement dated as of May 24, 2002, by and between MarkWest Energy Appalachia, L.L.C. and MarkWest Hydrocarbon, Inc.
10.7(12)	Second Amendment to the Gas Processing Agreement dated as of December 26, 2007, by and between MarkWest Energy Appalachia, L.L.C. and MarkWest Hydrocarbon, Inc.
10.8(2)+	Pipeline Liquids Transportation Agreement dated as of May 24, 2002, by and between MarkWest Energy Appalachia, L.L.C. and MarkWest Hydrocarbon, Inc.
10.9(2)	Natural Gas Liquids Purchase Agreement dated as of May 24, 2002, by and between MarkWest Energy Appalachia, L.L.C. and MarkWest Hydrocarbon, Inc.
10.10(3)	Services Agreement dated January 1, 2004 between MarkWest Energy GP, L.L.C. and MarkWest Hydrocarbon, Inc.

Exhibit Number	Description
10.11(7)	Office Lease Agreement, dated April 19, 2006, by and between Park Central Property LLC, the landlord, and MarkWest Energy Partners, L.P., the tenant.
10.12(8)+	Construction, Operation and Gas Gathering Agreement dated as of September 21, 2006 between MarkWest Western Oklahoma Gas Company, L.L.C. and Newfield Exploration Mid-Continent Inc.
10.13(11)+	Hydrogen Supply Agreement dated September 28, 2007, by and between MarkWest Blackhawk, L.P. and CITGO Refining and Chemicals Company L.P.
10.14(13)+	Gas Processing Agreement dated as of November 1, 2007, by and between MarkWest Javelina Company and CITGO Refining and Chemicals Company, L.P.
10.15(12)+	Amendment to Gas Processing Agreement dated as of December 11, 2007, by and between MarkWest Javelina Company and CITGO Refining and Chemicals Company, L.P.
10.16(12)	Omnibus Termination Agreement dated as of November 16, 2007, by and between MarkWest Energy Appalachia, L.L.C. and Equitable Production Company and Equitable Gathering LLC.
10.17(13)+	Natural Gas Liquids Transportation, Fractionation, and Marketing Agreement dated as of November 16, 2007, by and between MarkWest Energy Appalachia, L.L.C. and Equitable Gathering LLC.
10.18(12)	Assignment and Bill of Sale and Assumption Agreement dated as of November 16, 2007, by and between MarkWest Energy Appalachia, L.L.C. and Equitable Production Company and Equitable Gathering LLC.
10.19(19)+	Stiles/Britt Ranch Gas Gathering and Processing Agreement dated effective as of June 12, 2008 and executed August 5, 2008 between Newfield Exploration Mid-Continent Inc. and MarkWest Oklahoma Gas Company, L.L.C.
10.20(20)+	Natural Gas Liquids Purchase Agreement dated August 25, 2006 between ONEOK Hydrocarbon, L.P. and MarkWest Western Oklahoma Gas Company, L.L.C., now known as MarkWest Oklahoma Gas Company, L.L.C.
10.21(20)+	Amendment to the Natural Gas Liquids Purchase Agreement effective as of November 1, 2008 by and between MarkWest Oklahoma Gas Company, L.L.C. and ONEOK Hydrocarbon, L.P.
10.22(20)+	Raw Product Purchase Agreement dated February 11, 2005 between MarkWest Energy East Texas Gas Company, L.P., now known as MarkWest Energy East Texas Gas Company, L.L.C., and Dynegy Liquids Marketing and Trade, now known as Targa Liquids Marketing and Trade.
10.23(27)+	Amendment to the Raw Product Purchase Agreement effective as of December 1, 2009 by and between Targa Liquids Marketing and Trade and MarkWest Energy East Texas Gas Company, L.L.C.
10.24(23)+	Contribution Agreement dated as of January 22, 2009 by and among MarkWest Liberty Gas Gathering, L.L.C., M&R MWE Liberty, LLC, and MarkWest Liberty Midstream & Resources, L.L.C.
10.25(23)+	Amended and Restated Limited Liability Company Agreement of MarkWest Liberty Midstream & Resources, L.L.C. dated as of February 27, 2009.

Exhibit Number	Description
10.26(25)+	Letter Agreement dated August 10, 2009 between MarkWest Liberty Gas Gathering, L.L.C. and M&R MWE Liberty, LLC.
10.27(27)+	Second Amended and Restated Limited Liability Company Agreement of MarkWest Liberty Midstream & Resources, L.L.C. dated as of November 1, 2009.
10.28(27)	Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of MarkWest Liberty Midstream & Resources, L.L.C. dated as of November 20, 2009.
10.29(9)	Exchange Agreement dated September 5, 2007 by and among MarkWest Energy Partners, L.P., MarkWest Hydrocarbon, Inc., and MarkWest Energy, GP L.L.C.
10.30(9)	Voting Agreement dated September 5, 2007 by and among MarkWest Energy Partners, L.P. and the Fox Family Holders.
10.31(10)	Amended and Restated Class B Membership Interest Contribution Agreement dated October 26, 2007 by and among MarkWest Energy Partners, L.P. and John M. Fox, Donald C. Heppermann, Frank M. Semple, Nancy K. Buese, Randy S. Nickerson, John C. Mollenkopf, C. Corwin Bromley, Andrew L. Schroeder, Jan Kindrick, Cindy Kindrick, Kevin Kubat and Art Denney as the Sellers.
10.32(18)	Form of Second Amended and Restated Indemnification Agreement dated April 24, 2008 by and among MarkWest Energy Partners, L.P., MarkWest Energy GP, L.L.C., and each director and officer of MarkWest Energy GP, L.L.C., including the following named executive officers: Frank Semple, President and Chief Executive Officer; Nancy Buese, Senior Vice President and Chief Financial Officer; Randy Nickerson, Senior Vice President and Chief Commercial Officer; John Mollenkopf, Senior Vice President and Chief Operations Officer; and C. Corwin Bromley, Senior Vice President, General Counsel and Secretary.
10.33(2)	MarkWest Energy Partners, L.P. Long-Term Incentive Plan.
10.34(2)	First Amendment to MarkWest Energy Partners, L.P. Long-Term Incentive Plan.
10.35(18)	1996 Stock Incentive Plan for MarkWest Hydrocarbon, Inc.
10.36(18)	2006 Stock Incentive Plan for MarkWest Hydrocarbon, Inc.
10.37(15)	MarkWest Energy Partners, L.P. 2008 Long-Term Incentive Plan.
10.38(4)Δ	Executive Employment Agreement effective September 5, 2007 between MarkWest Hydrocarbon, Inc. and Frank Semple.
10.39(4)Δ	Form of Executive Employment Agreement effective September 5, 2007 between MarkWest Hydrocarbon, Inc. and Nancy K. Buese, C. Corwin Bromley, John C. Mollenkopf and Randy S. Nickerson.
12.1*	Computation of Ratio of Earnings to Fixed Charges
21.1*	List of subsidiaries
23.1*	Consent of Deloitte & Touche LLP
31.1*	Chief Executive Officer Certification Pursuant to Section 13a-14 of the Securities Exchange Act

Exhibit Number	Description
31.2*	Chief Financial Officer Certification Pursuant to Section 13a-14 of the Securities Exchange Act
32.1*	Certification of Chief Executive Officer of the General Partner 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 of the General Partner pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	The following financial information from the annual report on Form 10-K of MarkWest Energy Partners, L.P. for the year ended December 31, 2010, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Changes in Equity and Comprehensive Income, (iv) Consolidated Statements of Cash Flows, and (v) Notes to Consolidated Financial Statements, tagged as blocks of text.

(1) Incorporated by reference to the Registration Statement (No. 33-81780) on Form S-1 filed January 31, 2002.

(2) Incorporated by reference to the Current Report on Form 8-K filed June 7, 2002.

(3) Incorporated by reference to the Annual Report on Form 10-K filed March 15, 2004.

(4) Incorporated by reference to the Current Report on Form 8-K filed September 11, 2007.

(5) Incorporated by reference to the Current Report on Form 8-K filed July 7, 2006.

(6) Incorporated by reference to the Current Report on Form 8-K filed October 24, 2006.

(7) Incorporated by reference to the Current Report on Form 8-K filed April 25, 2006.

(8) Incorporated by reference to the Quarterly Report on Form 10-Q filed November 7, 2006.

(9) Incorporated by reference to the Current Report on Form 8-K filed September 6, 2007.

(10) Incorporated by reference to the Current Report on Form 8-K filed November 13, 2007.

(11) Incorporated by reference to the Quarterly Report on Form 10-Q filed November 8, 2007.

(12) Incorporated by reference to the Annual Report on Form 10-K filed February 29, 2008.

(13) Incorporated by reference to the Annual Report on Form 10-K/A filed May 8, 2008.

(14) Incorporated by reference to the Current Report on Form 8-K filed February 21, 2008.

(15) Incorporated by reference to the Form S-4/A Registration Statement filed December 21, 2007.

(16) Incorporated by reference to the Current Report on Form 8-K filed April 15, 2008.

(17) Incorporated by reference to the Current Report on Form 8-K filed May 1, 2008.

(18) Incorporated by reference to the Quarterly Report on Form 10-Q filed August 11, 2008.

(19) Incorporated by reference to the Quarterly Report on Form 10-Q filed November 10, 2008.

(20) Incorporated by reference to the Annual Report on Form 10-K filed March 2, 2009.

(21) Incorporated by reference to the Quarterly Report on Form 10-Q filed August 10, 2009.

(22) Incorporated by reference to the Registration Statement on Form S-3 filed January 13, 2010.

(23) Incorporated by reference to the Quarterly Report on Form 10-Q/A filed October 16, 2009.

(24) Incorporated by reference to the Form S-4 Registration Statement filed July 2, 2009.

(25) Incorporated by reference to the Quarterly Report on Form 10-Q filed November 9, 2009.

(26) Incorporated by reference to the Current Report on Form 8-K filed November 3, 2010.

(27) Incorporated by reference to the Annual Report on Form 10-K filed March 1, 2010.

(28) Incorporated by reference to the Current Report on Form 8-K filed July 7, 2010.

(29) Incorporated by reference to the Current Report on Form 8-K filed August 4, 2010.

(30) Incorporated by reference to the Current Report on Form 8-K filed February 24, 2011.

\+ Application has been made to the Securities and Exchange Commission for confidential treatment of certain provisions of these exhibits. Omitted material for which confidential treatment has been requested and has been filed separately with the Securities and Exchange Commission.

* Filed herewith.

Δ Identifies each management contract or compensatory plan or arrangement.

(b) The following exhibits are filed as part of this report: See Item 15(a)(2) above.

(c) The following financial statement schedules are filed as part of this report: None required.

SIGNATURES

Pursuant to the requirements of section 13 or 15(d) 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.

MarkWest Energy Partners, L.P.
(Registrant)
By: MarkWest Energy GP, L.L.C.,
Its General Partner

Date: February 28, 2011

By: /s/ FRANK M. SEMPLE
Frank M. Semple
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities with MarkWest Energy GP, L.L.C., the General Partner of MarkWest Energy Partners, L.P., the Registrant, and on the dates indicated.

Date: February 28, 2011

By: /s/ FRANK M. SEMPLE
Frank M. Semple
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

Date: February 28, 2011

By: /s/ NANCY K. BUESE
Nancy K. Buese
Senior Vice President and Chief Financial Officer
(Principal Financial Officer and
Principal Accounting Officer)

Date: February 28, 2011

By: /s/ DONALD D. WOLF
Donald D. Wolf
Lead Director

Date: February 28, 2011

By: /s/ KEITH E. BAILEY
Keith E. Bailey
Director

Date: February 28, 2011

By: /s/ MICHAEL L. BEATTY
Michael L. Beatty
Director

Date: February 28, 2011

By: /s/ CHARLES K. DEMPSTER

Charles K. Dempster
Director

Date: February 28, 2011

By: /s/ ANNE E. FOX MOUNSEY

Anne E. Fox Mounsey
Director

Date: February 28, 2011

By: /s/ DONALD C. HEPPERMANN

Donald C. Heppermann
Director

Date: February 28, 2011

By: /s/ WILLIAM A. KELLSTROM

William A. Kellstrom
Director

Date: February 28, 2011

By: /s/ WILLIAM P. NICOLETTI

William P. Nicoletti
Director

Corporate Information

BOARD OF DIRECTORS OF
MARKWEST ENERGY GP, L.L.C.
MARKWEST ENERGY PARTNERS, L.P.

Frank M. Semple
Chairman of the Board, President and Chief Executive Officer

Keith E. Bailey
Chairman of the Compensation Committee
Member of the Nominating and Corporate Governance Committee

Michael L. Beatty
Chairman of the Nominating and Corporate Governance Committee
Member of the Compensation Committee

Charles K. Dempster
Member of the Compensation Committee
Member of the Nominating and Corporate Governance Committee

Donald C. Heppermann
Chairman of the Finance Committee
Member of the Audit Committee

William A. Kellstrom
Member of the Audit Committee
Member of the Finance Committee

Anne E. Fox Mounsey
Member of the Compensation Committee
Member of the Nominating and Corporate Governance Committee

William P. Nicoletti
Chairman of the Audit Committee
Member of the Finance Committee

Donald D. Wolf
Lead Director

EXECUTIVE OFFICERS OF
MARKWEST ENERGY GP, L.L.C.
MARKWEST ENERGY PARTNERS, L.P.

Frank M. Semple
Chairman of the Board, President and Chief Executive Officer

C. Corwin Bromley
Senior Vice President, General Counsel and Secretary

Nancy K. Buese
Senior Vice President and Chief Financial Officer

John C. Mollenkopf
Senior Vice President and Chief Operating Officer

Randy S. Nickerson
Senior Vice President and Chief Commercial Officer

CONTACT INFORMATION

MarkWest Energy Partners, L.P.
1515 Arapahoe Street
Tower 1, Suite 1600
Denver, Colorado 80202-2137
Tel: 800.730.8388
Fax: 303.290.8769
Website: www.markwest.com

Investor Relations
Tel: 866.858.0482
Email:
investorrelations@markwest.com

TRANSFER AGENT AND REGISTRAR

Wells Fargo Shareowner Services
Tel: 800.468.9716
Website: www.shareowneronline.com
Send unitholder inquiries to:
Wells Fargo Shareowner Services
161 North Concord Exchange
South St. Paul, Minnesota 55075

COMMON UNIT LISTING

New York Stock Exchange
Ticker Symbol: MWE

NYSE AND SEC CERTIFICATIONS

The annual CEO certification required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual was submitted without qualification by Frank M. Semple on July 1, 2010.

MarkWest's Chief Executive Officer and Chief Financial Officer have provided certifications to the U.S. Securities and Exchange Commission as required by Section 302 of the Sarbanes-Oxley Act of 2002. These certifications are included as Exhibits 31.1 and 31.2 to the Partnership's Form 10-K for the year ended December 31, 2010.

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Our Core Principles

MarkWest believes every employee is important to the success of the company and is committed to building a performance-oriented culture based on trust, accountability, safety, and teamwork.

MarkWest strives to deliver best-of-class midstream services that consistently exceed the expectations of its producer customers.

MarkWest encourages innovative solutions to complex problems at all levels within the company.

MarkWest contributes to the development of environmentally clean energy while utilizing ecologically friendly practices and complying with or exceeding regulatory requirements.

MarkWest's reputation rests on its ability to operate in accordance with the principles of honesty, integrity, and trustworthiness.

MARKWEST
Energy Partners, L.P.

1515 Arapahoe Street
Tower 1, Suite 1600
Denver, Colorado 80202-2137
www.markwest.com

MarkWest Energy Partners' 2010 Annual Report saved the following resources by printing on paper containing up to 100% recycled fiber:

57 trees preserved for the future

18 million BTUs of energy not consumed

26,182 gallons of wastewater flow saved

1,590 pounds of solid waste not generated

5,436 pounds net of greenhouse gases prevented

FSC MIX Paper from responsible sources FSC® C013980