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2011 ANNUAL REPORT

ENERGY TO MOVE FORWARD

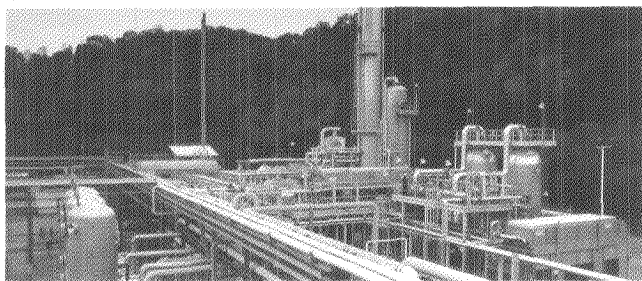
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MARKWEST ENERGY PARTNERS, L.P.



LIBERTY

The Liberty Segment provides natural gas mid-stream services in the liquids-rich area of the Marcellus Shale. We are the largest processor of natural gas with fully integrated processing, fractionation, storage, and marketing operations that are critical to the development of the Marcellus Shale.

AREAS OF OPERATION

Southwest Pennsylvania and northern West Virginia

RESOURCE PLAY

Marcellus Shale

GATHERING

325 MMcf/d gathering capacity

PROCESSING

625 MMcf/d cryogenic processing capacity

FRACTIONATION

60,000 Bbl/d C3+ fractionation

Under Construction

PROCESSING

1.1 Bcf/d cryogenic processing capacity at Majorsville, Mobley, and Sherwood complexes

FRACTIONATION

115,000 Bbl/d de-ethanization capacity at Houston, PA and Majorsville, WV complexes

OTHER

50,000 Bbl/d Mariner West purity ethane pipeline project

Rail loading for 200 railcars

Multiple NGL and ethane pipelines

% OF MARKWEST'S NET OPERATING MARGIN*

19%



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, isobutene, normal butane, butylenes, and pentanes

High-purity hydrogen production

**See note on cover page to Annual Report on Form 10-K for important disclosures regarding this non-GAAP financial measure.*

% OF MARKWEST'S NET OPERATING MARGIN*

12%



SOUTHWEST

In the Southwest Segment, we gather, process, treat, and transport natural gas and natural gas liquids (NGLs) in four operating areas, including East Texas, Southeast Oklahoma, Western Oklahoma, and Other Southwest.

Our assets in the Southwest include numerous 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, and Louisiana

RESOURCE PLAYS

Woodford Shale, Granite Wash, Haynesville Shale, Anadarko Basin, and the Cotton Valley, Travis Peak, and Petit Formations

GATHERING

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

PROCESSING

655 Million cubic feet per day (MMcf/d) processing capacity

TRANSPORTATION

1.5 Bcf/d intrastate transportation capacity

OTHER

Arkoma Connector Pipeline JV with ArcLight Capital Partners

Under Construction

PROCESSING

120 MMcf/d cryogenic processing capacity in East Texas

% OF MARKWEST'S NET OPERATING MARGIN*

49%



NORTHEAST

We are the largest processor and fractionator of natural gas and NGLs in the southern Appalachian basin. 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

STORAGE

285,000 barrel propane storage capacity

OTHER

NGL marketing by truck, rail, and barge

Under Construction

PROCESSING

150 MMcf/d cryogenic processing capacity at Langley, Kentucky, complex

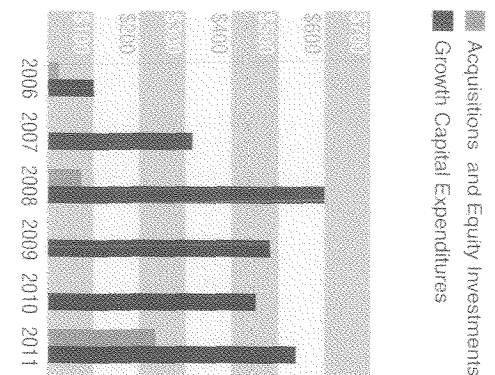
% OF MARKWEST'S NET OPERATING MARGIN*

20%

FINANCIAL HIGHLIGHTS

Growth Capital Investment

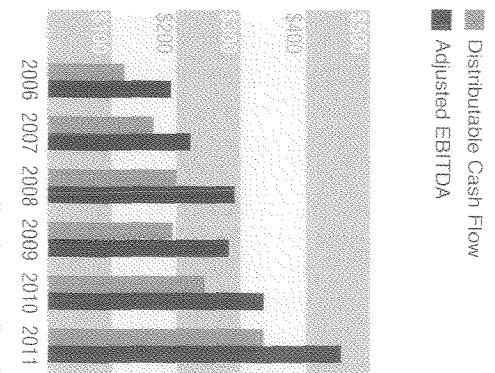
(\$ in millions)



NOTE: Numbers include growth capital that has been funded through joint ventures and divestiture activities. For additional information, see Item 6 - Selected Financial Data of this Annual Report on Form 10-K.

Financial Performance

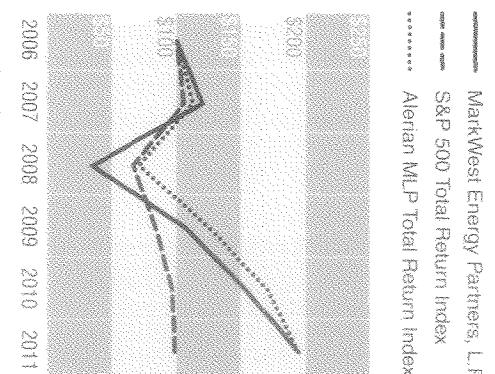
(\$ in millions)



NOTE: See note on cover page to Annual Report on Form 10-K for important disclosures regarding these non-GAAP financial measures.

Total Return to Stockholders

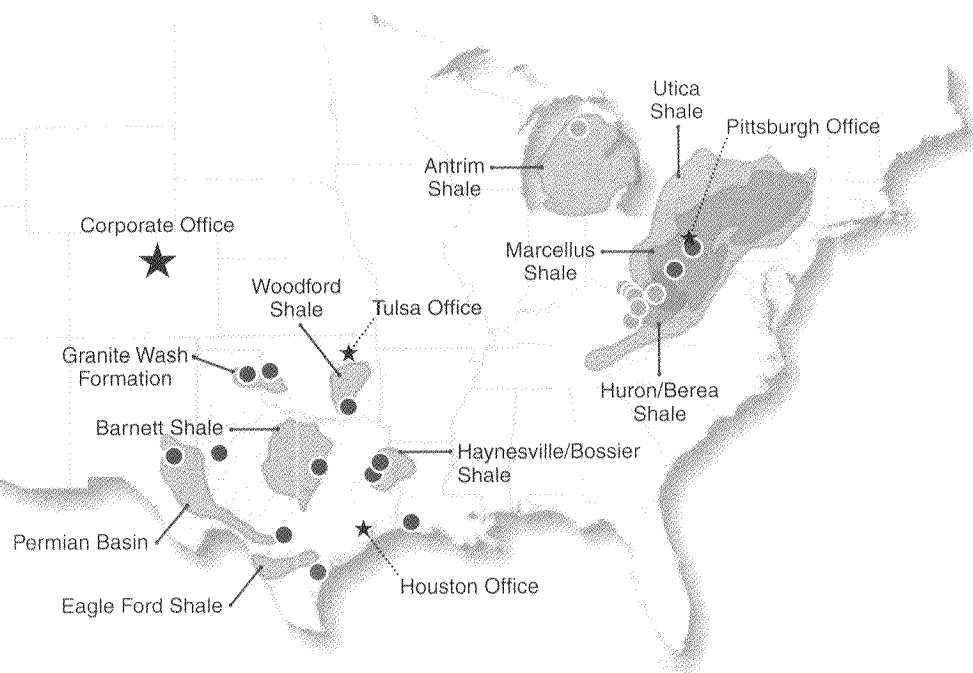
(assumes \$100 investment on 12/31/05)



Source: Bloomberg



AREAS OF OPERATION



○ Southwest ○ Northeast ○ Liberty ○ Gulf Coast ☆ MarkWest Offices

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 cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. The Partnership undertakes no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise. 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 2011, 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.

LETTER TO UNITHOLDERS

EXCEPTIONAL CUSTOMER SERVICE ONCE AGAIN DROVE STRONG OPERATIONAL PERFORMANCE AND ANOTHER YEAR OF RECORD FINANCIAL RESULTS IN 2011.



We continued to execute significant growth projects while maintaining our focus on some of the best resource plays in the United States, which we believe will continue to provide long-term, dependable distribution growth for our unitholders.

In 2011, we achieved record distributable cash flow (DCF) of \$333 million and record Adjusted EBITDA of \$451 million, which represent year-over-year increases of approximately 38 percent and 36 percent, respectively. DCF per unit grew by more than 20 percent in 2011 and we maintained a full-year distribution coverage ratio of 1.38. We raised \$2.3 billion in capital from the public equity and debt markets to support our significant growth while simultaneously lowering our long-term weighted average cost of capital. As a result, we achieved upgrades from the ratings agencies in 2011, and we are well capitalized to fund our capital program. Overall, we delivered strong financial performance in 2011 and our significant growth capital forecast, including our development plans for the Utica shale, are confirmation that we are not slowing down in 2012.

We continue to execute our hedging program to manage the risks associated with commodity prices and to provide stability of cash flows. For 2012 we are currently hedged at approximately 65 percent of our commodity price exposure, measured volumetrically; and for 2013 and 2014, we are hedged at approximately

55 percent and 20 percent, respectively. This hedging philosophy continues to be a key priority given our long-term objective to protect and grow our distributions.

A key part of our operational strategy is to provide exceptional customer service. In 2011, we were again

With our diverse set of assets in growing resource plays, managed by a team recognized for exceptional customer service, we are very well positioned to continue developing midstream solutions for our producer customers.

ranked number one in the Energy Point midstream industry survey. Energy Point compiles rankings in eight major categories, as well as service-specific and region-specific rankings. Of the eight major categories, we were ranked first in five of the categories, including total

customer satisfaction, pricing and contract terms, project development, service and professionalism, and personnel. We also ranked first in natural gas liquid (NGL) transportation and storage, and first in the Marcellus and East Texas regions. We are very proud of these rankings because they validate the hard work of our employees, who consistently work to understand our customer's needs and deliver best-in-class midstream services.

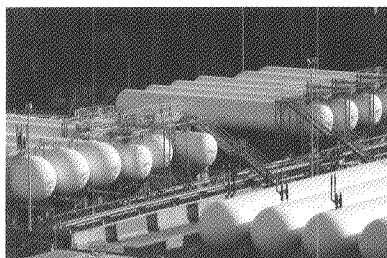
Our Southwest Segment includes operations in Texas and Oklahoma. Gathering volumes in this segment increased approximately 2 percent in 2011, driven primarily by a 38 percent increase in volumes in the Granite Wash. A 75 million cubic feet per day (MMcf/d) cryogenic expansion at our Arapaho processing complex came online in 2011 to support the growth in liquids-rich volumes from the Granite Wash. Our processing capacity in Western Oklahoma is now 235 MMcf/d, and we are currently operating near capacity.

In Southeast Oklahoma, our gathered volumes remained strong at more than 500 MMcf/d, and our processed volumes were greater than 100 MMcf/d. The volume of gas that we processed in Southeast Oklahoma increased by nearly 30 percent compared to 2010, which continues to provide a healthy uplift in operating margin.

There are tremendous reserves yet to be drilled in the unconventional plays

in which we operate in Oklahoma, and we continue to be ideally positioned to further expand our presence in the Southwest.

In East Texas, we recently signed new long-term agreements with Anadarko, Chevron, PetroQuest, and Samson Lone Star, which have plans to aggressively develop the liquids-rich areas of the horizontal Cotton Valley and the Haynesville Shale. As a result, we are adding processing capacity of 120 MMcf/d with the Carthage East plant expected to come online in early 2013, increasing total processing in East Texas to 400 MMcf/d. Our East Texas assets continue to be among the most profitable in the company, and we look forward to many more years of strong operational and financial performance from these assets.



Our Javelina plant in Corpus Christi, Texas, continues to be a solid performer, both operationally and financially. Processed volumes and fractionated barrels were relatively flat in 2011, while segment operating income increased by more than 10 percent, primarily as a result of strong prices for purity products. Javelina continues to be a key part of our operations and provides important diversity and stability to our cash flows.

Our Appalachian operations include our Liberty and Northeast segments. We are the largest processor and fractionator in Appalachia. Today we have processing capacity in excess of 1 billion cubic feet per day (Bcf/d), fractionation capacity of 84,000 barrels per day (Bbl/d), and a significant NGL pipeline network, essentially

all of which is supported by long-term contracts.

In the Northeast Segment, our processed volumes increased significantly in 2011, primarily as a result of our acquisition of the Langley processing facilities in southern Kentucky from EQT. We are currently increasing the processing capacity at the Langley plant, which will come online later this year. While certain producers have indicated plans to curtail drilling in the short-term, we remain focused on staying ahead of our customers' long-term requirements by continuing to invest in strategic, high-return mid-stream projects.

In the Liberty Segment, we continued to see significant volume growth in 2011 highlighted by gathered volumes increasing by more than 70 percent,



processed volumes increasing by 50 percent, and fractionated volumes increasing by nearly three times. Today we operate an extensive and expanding gathering system, 625 MMcf/d of processing capacity, and a 60,000 Bbl/d fractionator. In December we acquired the 49 percent of the Liberty joint venture previously owned by the Energy and Minerals Group (EMG). While EMG has been a great partner for three years, we are very pleased to now own 100 percent of the Liberty assets in one of the best shale plays in the United States.

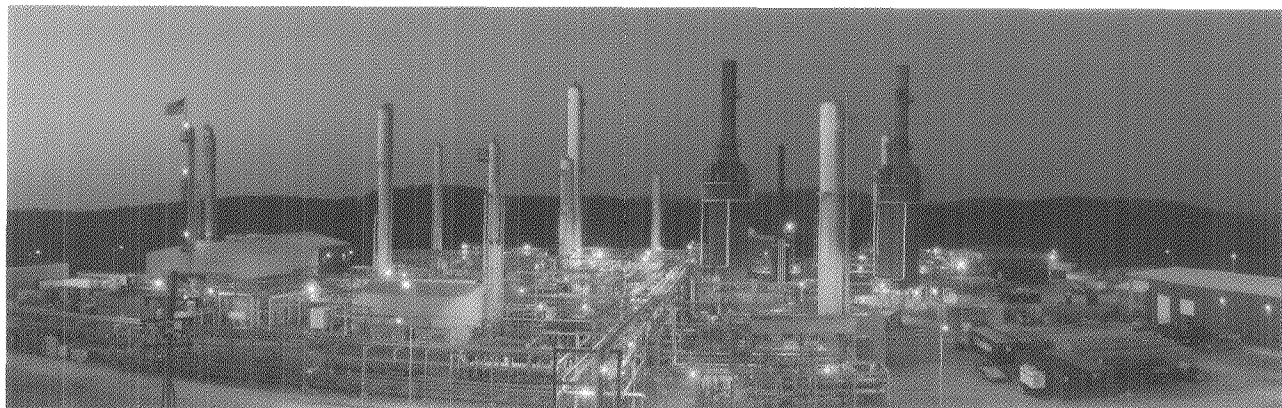
We continue to execute on projects critical to the full development of liquids-rich Marcellus acreage. Our current projects include the construction of six additional cryogenic processing plants supported by long-term agreements with Antero, Consol, EQT, Magnum

Hunter, Noble, and Range. Other significant projects under construction include three de-ethanization facilities at Majorsville and Houston, with combined capacity to produce approximately 115,000 Bbl/d of purity ethane; approximately 400 miles of gas gathering, NGL, and purity ethane pipelines; and a 200-car rail facility at our Houston complex. When these projects are completed, our processing capacity will increase to more than 1.7 Bcf/d, and our total fractionation capacity will increase to approximately 175,000 Bbl/d.

Capturing premium natural gas liquid pricing is critical for producers in the Marcellus, and we are in a very favorable position to leverage premium price opportunities for our producer customers because of our large-scale NGL infrastructure.



In addition, we formed a joint venture with EMG to develop the liquids-rich region of the Utica Shale in eastern Ohio. We will develop large, integrated, full-service midstream infrastructure similar to our approach in the Marcellus. Our initial development plans include extensive natural gas gathering infrastructure primarily in Harrison, Guernsey, and Belmont counties, which is expected to come online beginning in 2012. In addition, we are developing 200 MMcf/d processing complexes in Noble and Harrison counties and 100,000 Bbl/d of fractionation capacity in Harrison County. The Noble and Harrison processing plants will be connected to the fractionator by an NGL pipeline. The Harrison County facility will fractionate NGLs from both the Marcellus



and the Utica, which will allow us to cost-effectively expand our Marcellus fractionation capacity under long-term contracts and create world-class midstream facilities in the heart of the Utica, the majority of which will be base-loaded by Marcellus NGL production. Houston and Harrison will be the two largest fractionation complexes in the Northeast, and by connecting the two through an NGL gathering pipeline, we will have tremendous operating flexibility and reliability, as well as market access. The Harrison fractionator will be owned jointly by MarkWest Liberty and the Utica joint venture, and the capital required to build the complex will be shared accordingly.

It's important to note that up to the first \$500 million of capital expenditures for the Utica joint venture will be funded by EMG, after which MarkWest will fund 100 percent of capital requirements until we achieve 70 percent ownership. However, MarkWest will receive 60 percent of the distributions for the first five years or until our ownership exceeds 60 percent. Although we are still in the early stages of development of the Utica shale, we are very excited about the play, which we believe will drive significant long-term, high-quality investment opportunities.

With our existing NGL infrastructure and the completion of our ethane and fractionation facilities, our plants will be key supply sources for Northeast

ethane pipeline projects. Our Mariner projects are being developed in partnership with Sunoco Logistics. Mariner West will transport purity ethane to Sarnia, Ontario, Canada beginning in mid-2013. Mariner East is under development and would transport an ethane/propane mix to Philadelphia. The ethane could be shipped to Gulf Coast or international markets, including Europe, and the propane could be exported to Caribbean, South American, and

\$451M

Record Adjusted
EBITDA in 2011

European markets. In addition, we will deliver ethane to the Enterprise ATEX Express pipeline that will transport ethane to the Gulf Coast and is expected to be in service in the first quarter of 2014. We believe that these projects adequately address the necessary ethane takeaway capacity from the Northeast and provide exciting opportunities for exporting propane.

By 2014, our operations in the Marcellus, Utica, and Huron/Berea resource plays will have total processing capacity of more than 2.5 Bcf/d and fractionation capacity

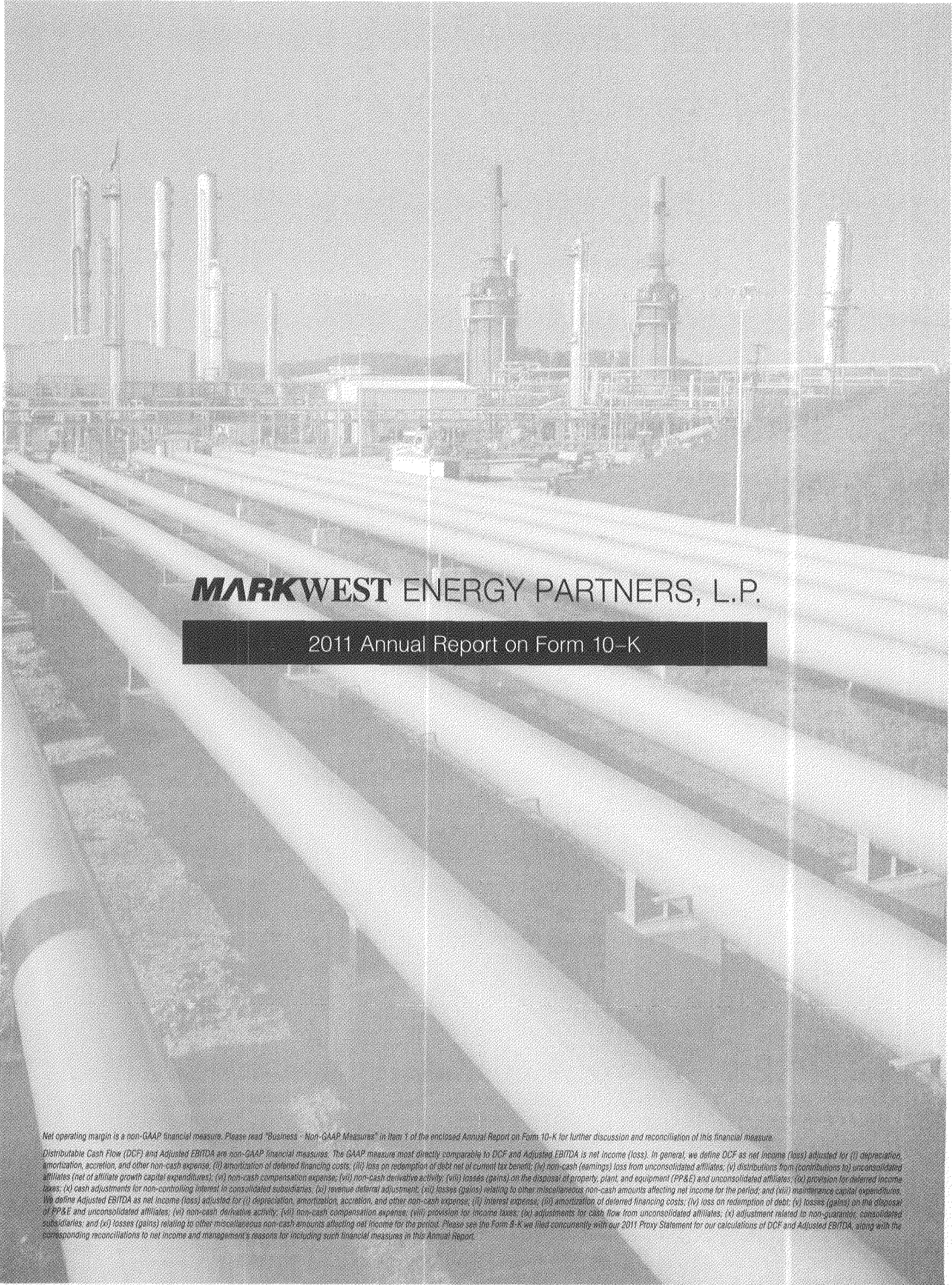
of approximately 300,000 Bbl/d, including the capacity to produce 155,000 Bbl/d of purity ethane. We have a long history of constructing and operating integrated midstream facilities and providing reliable and flexible solutions for our producer customers. Appalachia is where MarkWest started almost 25 years ago, and it is exciting to be a part of the long-term development of these resource plays, which is creating tremendous economic benefits and thousands of jobs in Pennsylvania, West Virginia, Ohio, and Kentucky.

In summary, 2011 was another very strong year, both operationally and financially. With our diverse set of assets in growing resource plays, managed by a team recognized for exceptional customer service, we are very well positioned to continue developing midstream solutions for our producer customers. These growth opportunities, coupled with the strength of our balance sheet, continue to support our objective to provide superior and sustainable total returns for our unitholders.

Thank you for your continued support.

Frank M. Semple
Chairman, President and
Chief Executive Officer

April 15, 2012



MARKWEST ENERGY PARTNERS, L.P.

2011 Annual Report on Form 10-K

Net operating margin is a non-GAAP financial measure. Please read "Business - Non-GAAP Measures" in Item 1 of the enclosed Annual Report on Form 10-K for further discussion and reconciliation of this financial measure.

Distributable Cash Flow (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) revenue deferral adjustment; (xii) losses (gains) relating to other miscellaneous non-cash amounts affecting net income for the period; and (xiii) 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-guarantee, consolidated subsidiaries; and (xi) losses (gains) relating to other miscellaneous non-cash amounts affecting net income for the period. Please see the Form 9-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.

**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, 2011

or

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

for the transition period from _____ to _____

Commission File Number 001-31239

MARKWEST ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of
incorporation or organization)

27-0005456
(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 to 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 Smaller reporting company
(Do not check if a 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, 2011 was approximately \$3.6 billion. As of February 17, 2012, the number of the registrant's common units and Class B units outstanding were 95,908,615 and 19,954,389, respectively.

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 2012, 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

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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, 2011. References to “MarkWest Hydrocarbon” or the “Corporation” are intended to mean MarkWest Hydrocarbon, Inc., a wholly-owned taxable subsidiary of the Partnership. References to “General Partner” are intended to mean MarkWest Energy GP, L.L.C., the general partner 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
Bcf/d	Billion cubic feet 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
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
Mcf	One thousand cubic feet of natural gas
Mcf/d	One thousand cubic feet of natural gas per day
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)	Segment 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
SMR	Steam methane reformer, operated by a third party and located at the Javelina gas processing and fractionation facility in Corpus Christi, Texas
TSR Performance Units	Phantom units containing performance vesting criteria related to the Partnership's total shareholder return
VIE	Variable interest entity
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 those described in (i) Item 1A. Risk Factors of this Form 10-K and elsewhere in this report, (ii) our reports and registration statements filed from time to time with the SEC and (iii) other announcements we make from time to time. Investors are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

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 the following 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, 2011 (amounts in thousands). For further discussion of our segments and a reconciliation to our consolidated statement of operations, see Note 24 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

	<u>Southwest</u>	<u>Northeast</u>	<u>Liberty</u>	<u>Gulf Coast</u>	<u>Total</u>
Revenue	\$935,513	\$268,884	\$248,949	\$96,473	\$1,549,819
Purchased product costs	506,911	91,612	83,847	—	682,370
Net operating margin(1)	428,602	177,272	165,102	96,473	867,449
Facility expenses	82,761	27,126	34,913	38,436	183,236
Portion of operating income attributable to non-controlling interests	5,431	—	63,731	—	69,162
Operating income before items not allocated to segments	<u>\$340,410</u>	<u>\$150,146</u>	<u>\$ 66,458</u>	<u>\$58,037</u>	<u>\$ 615,051</u>

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

Organizational Structure

We are a master limited partnership with outstanding common units, Class A units and Class B units.

- Our common units are publicly traded on the New York Stock Exchange under the symbol “MWE.”.
- All of our Class A units are owned by MarkWest Hydrocarbon and our General Partner, which are our wholly-owned subsidiaries. The unregistered 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 Class A units share, on a pro-rata basis, in the income or loss of the Partnership except for those items described in (ii) above. The ownership structure, whereby our Class A units are held by

MarkWest Hydrocarbon and the General Partner, was adopted upon the merger of the Partnership and MarkWest Hydrocarbon in February 2008 (the “Merger”).

- All of our Class B units were issued to and are held by M&R MWE Liberty, LLC (“M&R”), an affiliate of The Energy and Minerals Group (“EMG”) as part of our December 31, 2011 acquisition of the non-controlling interest in MarkWest Liberty Midstream & Resources, L.L.C. (“MarkWest Liberty Midstream”). See *Recent Developments* below for further discussion. The unregistered Class B units will convert to common units on a one-for-one basis (the “Converted Units”) in five equal installments beginning on July 1, 2013 and each of the first four anniversaries of such date. Class B units (i) are not entitled to participate in any distributions of available cash prior to their conversion and (ii) 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) other than those matters that disproportionately and adversely affect the rights and preferences of the Class B units. Upon conversion of the Class B units, the right of M&R and certain of its affiliates to vote as a common unitholder of the Partnership will be limited to a maximum of 5% of the Partnership’s outstanding common units. Once converted, M&R and certain of its affiliates will have the right to participate in underwritten offerings of our Partnership in an amount up to 20% of the total number of common units offered and will have comparable 20% participation and sale rights if the Partnership adopts a continuous equity or similar program in the future. M&R also has limited rights to distribute an aggregate of 2,500,000 common units to its members and their limited partners beginning in 2016, and M&R and certain of its affiliates will have the right to demand that we conduct up to three underwritten offerings beginning in 2017, but restricted to no more than one offering in any twelve-month period. Except as described above, M&R is not permitted to transfer its Class B units or Converted Units without the prior written consent of the General Partner’s board of directors (the “Board”).

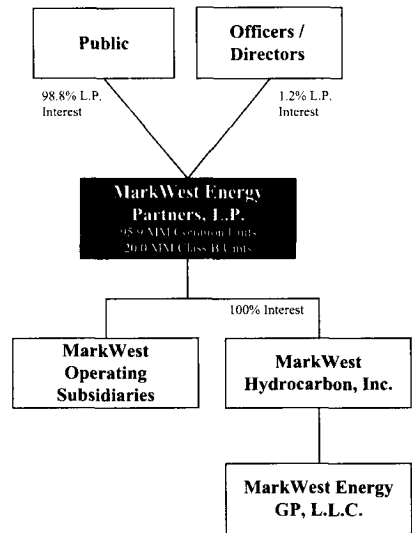
The following table provides the aggregate number of units and relative ownership interests of the Class A and B units and common units as of February 17, 2012 (units in millions):

	<u>Units</u>	<u>%</u>
Common units	95.9	69.2%
Class A units	22.6	16.3%
Class B units	<u>20.0</u>	<u>14.5%</u>
Total units	<u>138.5</u>	<u>100%</u>

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 17, 2012 in the graphic depicted below reflect the Partnership structure

from the basis of the consolidated financial statements with the Class A units eliminated in consolidation. All Class B units are owned by the public.

Current Ownership Structure



The primary benefit of our organizational structure is the absence of incentive distribution rights, which prior to our Merger, 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

Acquisition of Non-controlling Interest in MarkWest Liberty Midstream

Effective December 31, 2011, we acquired the 49% interest in MarkWest Liberty Midstream held by M&R for consideration of approximately \$994 million of cash and the issuance of approximately 19,954,000 unregistered Class B units valued at approximately \$753 million. We also incurred approximately \$4 million in third-party transaction costs. As a result, we own 100% of MarkWest Liberty Midstream as of December 31, 2011. Please refer to the *Organizational Structure* for a description of the Class B units and refer to Note 4 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion of the accounting treatment of the acquisition.

Utica Shale Joint Venture

Effective January 1, 2012, we and EMG Utica, LLC (“EMG Utica”), an affiliate of EMG, executed agreements to form a Utica Shale midstream joint venture (the “Utica Joint Venture”) operated through MarkWest Utica EMG, L.L.C. (“MarkWest Utica EMG”) to develop significant natural gas processing and NGL fractionation, transportation and marketing infrastructure in Eastern Ohio beginning in 2012. Under the terms of the agreements, EMG Utica is obligated to fund the initial capital expenditures of MarkWest Utica EMG, up to the first \$500 million.

The first phase of the Utica development plan includes two new processing complexes and 100,000 Bbl/d of fractionation, storage and marketing capacity. The initial processing plant in Harrison County is expected to have a capacity of 200 MMcf/d and begin initial operations in mid-2013. MarkWest is finalizing the design capacity and the location of the second processing complex, which is also expected to begin operations in 2013. Both processing complexes are expected to be connected via an NGL gathering system to the fractionation facilities in Harrison County that are anticipated to be operational in 2013.

Common Unit Offerings

On December 19, 2011, we completed a public offering of 10.0 million newly issued common units representing limited partner interests. On January 13, 2012, we issued an additional 0.7 million units pursuant to the underwriters' exercise of their option to purchase additional common units. The total net proceeds of the offering, including the exercise of the underwriters' option, were approximately \$559 million and were primarily used to partially fund the cash consideration for the acquisition of the 49% non-controlling interest in MarkWest Liberty Midstream. We completed additional public offerings earlier in 2011 and, in total, issued 23.2 million common units receiving net proceeds of approximately \$1.1 billion. Refer to Note 17 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion of the accounting treatment of the common unit offering.

Credit Facility

On December 29, 2011, we amended our revolving credit facility as provided under the Amended and Restated Revolving Credit Agreement dated July 1, 2010, as amended ("Credit Facility") to increase the borrowing capacity to \$900 million, and to reset the uncommitted accordion feature of \$250 million, providing us with the additional financial flexibility to continue to execute our growth strategy. Earlier in 2011, we had amended the Credit Facility to reduce the interest rates and extend the maturity date to September 2016. See Note 16 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further details of our Credit Facility.

Senior Notes Offerings and Tender Offers

During 2011, we completed a public offering for \$500 million in aggregate principal amount of 6.5% senior notes due in August 2021 ("2021 Senior Notes") and a public offering for \$700 million in aggregate principal amount of 6.25% senior notes due in June 2022 ("2022 Senior Notes"). A portion of the \$1.2 billion combined net proceeds from these offerings was used to repurchase \$275 million aggregate principal amount of our 8.5% senior notes due in July 2016 and approximately \$419 million aggregate principal amount of our 8.75% senior notes due in April 2018, with the remainder used to provide additional capital for general partnership purposes and to fund our capital expenditures. As a result of these refinancing activities, we have significantly reduced the interest rates and extended the terms of our long-term financing. See Note 16 of the accompanying Notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K for more details of these senior notes transactions and discussion of the accounting impacts.

Expansion of Marcellus Shale Operations

During the third quarter of 2011, we began operations of our fractionation facility at our Houston, Pennsylvania processing complex ("Houston Complex") with a design capacity of 60,000 barrels per day. This was a significant milestone in our continued development of our fully integrated midstream services in the Marcellus Shale.

In January 2012, we announced the 400 MMcf/d expansion of our processing facilities in Majorsville, West Virginia (“Majorsville Complex”), which would bring the total cryogenic processing capacity at the Majorsville Complex to 670 MMcf/d. The expansion of the Majorsville Complex includes two, 200 MMcf/d processing trains that are expected to begin operations in 2013 and will be supported by long-term agreements with CONSOL Energy, Noble Energy and Range Resources.

In February 2012, we announced plans to expand the capacity of our processing facilities in Sherwood, West Virginia (“Sherwood Complex”) with an additional 200 MMcf/d cryogenic processing plant that is expected to be completed in 2013. The expansion plans are based, in part, on a producer customer’s decision to support the additional capacity under a long-term processing agreement. The producer customer has publicly stated its intent to move forward with the project but must make its final decision on whether to proceed with the additional plant at the Sherwood Complex by July 1, 2012.

See *Our Operating Segments* below for additional discussion of our existing operations and planned expansion in Liberty and other segments.

Business Strategy

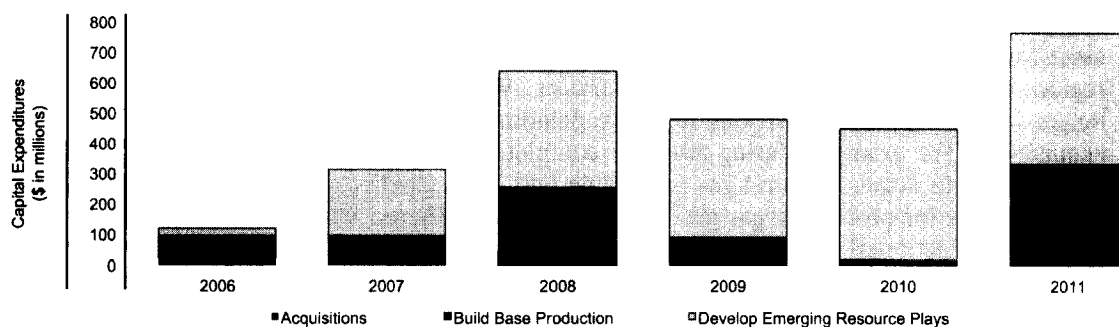
Our primary business strategy is to provide top-tier midstream services by developing and operating high-quality, strategically located assets in the liquids-rich areas of the emerging resource plays in the United States. We plan to accomplish this through the following:

- *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 Haynesville Shale, the Granite Wash, the Marcellus Shale and the Huron/Berea Shale. We intend to continue to develop relationships that are characterized by joint planning for the development of the emerging resource plays, such as the Utica Shale, 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 2011, we spent approximately \$551 million of total capital to develop midstream infrastructure in the Marcellus Shale and to expand several of our gathering and processing operations in our Southwest segment, including the Western Oklahoma gas processing plant.
- *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 acquisitions. For example, during 2011, we completed the Langley Acquisition for approximately \$231 million to acquire natural gas processing and NGL pipeline assets located in Kentucky and West Virginia for processing gas produced in the Huron/Berea Shale and transporting NGLs to our Siloam fractionation facility. In addition, we acquired the non-controlling 49% interest in MarkWest Liberty Midstream for consideration of \$994 million in cash and approximately 19,954,000 unregistered Class B units valued at approximately \$753 million. Please refer to Note 4 of the accompanying Notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion of the acquisition of non-controlling interest.
- *Maintaining our financial flexibility.* Our goal is to maintain a capital structure with approximately equal amounts of debt and equity financing on a long-term prospective basis. During 2011, we

raised approximately \$2.3 billion by strategically accessing 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 16 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 amendments to our Credit Facility to expand the borrowing capacity from \$705 million to \$900 million and to extend the term to September 2016. As of December 31, 2011, we and our wholly-owned subsidiaries had approximately \$117 million of cash and cash equivalents and we had approximately \$815 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 estimate that fee-based contracts will account for greater than 50% of our net operating margin in 2013. 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 commodity risk management 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 many 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 and NGL production. Additionally, we have recently announced plans for the development of operations in the Utica Shale. The following table summarizes the magnitude of the growth projects and acquisitions, including equity investments. The amounts include the portion of our growth projects funded by contributions from our joint venture partners.



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

- *Leading position in the liquids-rich areas of the northeast United States.* Since our inception, we have been the largest processor and fractionator in the northeast United States and we continue

to strengthen our position in this critical growth area that is driven by the development of the Marcellus, Huron/Berea, and Utica shale formations. Currently, our Northeast and Liberty segments have combined processing capacity in excess of 1.1 Bcf/d and combined fractionation capacity of nearly 85,000 barrels per day, as well as an integrated NGL pipeline, storage and marketing infrastructure. Our processing and fractionation capacity is supported by strategic long-term agreements that include significant acreage dedications from key producers. We believe our significant presence and asset base provide us with a competitive advantage in capturing and contracting for new supplies of natural gas as the production from these shale formations continues to be developed, particularly in the liquids-rich area of the region as evidenced by the recently announced development plans for the Utica Shale.

- *Strategic and growing position with high-quality assets in the Southwest and the Gulf Coast.* Our acquisitions and internal growth projects since inception 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 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 processing and fractionation 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.

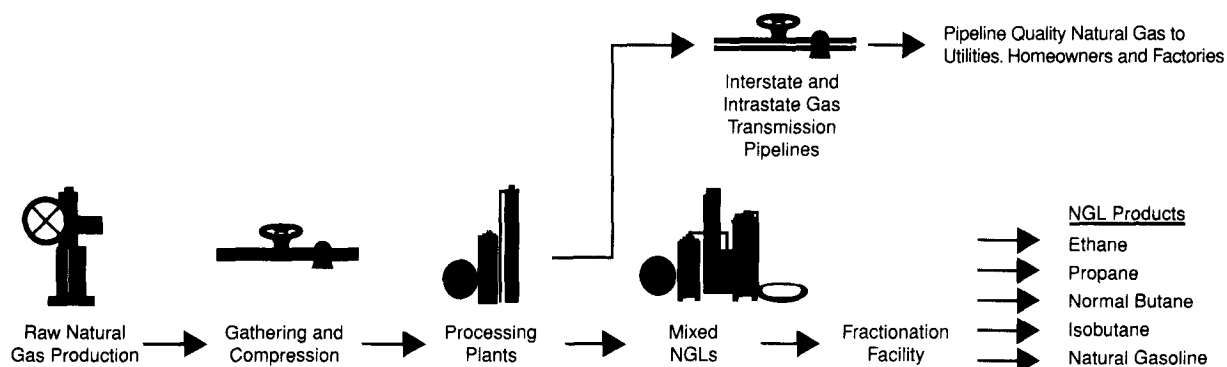
- *Long-term Contracts.* We believe our long-term contracts, which we define as contracts with remaining terms of four years or more, lend greater stability to our cash flow profile. In East Texas, approximately 43% of our current gathering volumes are under contract for longer than 4 years as of December 31, 2011. 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 6 years. Approximately 93% of our throughput in the Woodford gathering system is subject to contracts with remaining terms of more than 5 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 9 and 17 years. In Appalachia, our natural gas processing and NGL fractionation and exchange contracts with remaining terms of

more than 4 years account for approximately 77% of our volumes, with 60% of volumes subject to contracts with terms of at least 10 years. In the Gulf Coast segment, approximately 74% of our volumes are under contract for more than 7 years. In the Liberty segment, all of our current gathering and processing agreements with significant dedicated acreage have remaining terms of at least 9 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 midstream infrastructure 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 13 acquisitions as of December 31, 2011, including the acquisition of the non-controlling interest in MarkWest Liberty Midstream effective December 31, 2011.

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:



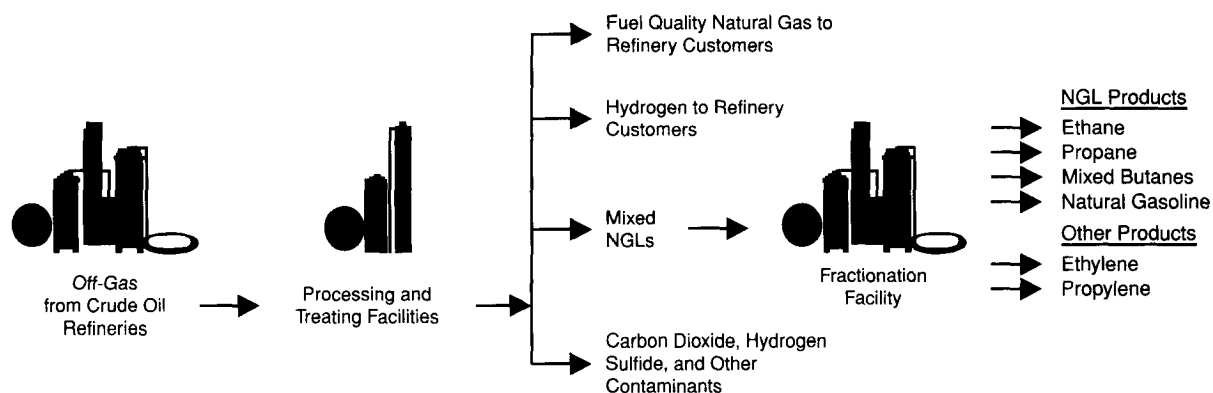
The natural gas production process begins with the drilling of wells into gas-bearing rock formations. The gathering process begins when a producing well is connected to a gathering system. Gathering systems typically consist of a network of small diameter pipelines and, if necessary, compression systems 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.

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 currently recovered from the natural gas stream in our Northeast and Liberty segments. However, we are developing projects that would allow us to recover ethane and provide our producer customers with access to markets for the ethane produced in the Liberty

segment, which are expected to begin operations in mid-2013. See *Our Operating Segments—Liberty Segment* below in this Item 1 for further discussion of our ethane solution.

- *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 the following operating segments: Southwest, Northeast, Liberty and Gulf Coast. Our assets and operations in each of these segments are described below. In addition, we include a description of the initial planned development of the Utica segment.

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 77% of our natural gas volumes in the East Texas System result from contracts with 6 producers in 2011. 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 19.4% of our consolidated revenue in 2011. The initial 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. The liquids-rich natural gas gathered in the Woodford system is processed through Centrahoma Processing LLC (“Centrahoma”), our equity investment, or other third-party processors. In addition, we own the Foss Lake natural gas gathering system and the Western Oklahoma natural gas processing complex, all located in Roger Mills, Beckham, 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 a gathering system in the Granite Wash formation in Wheeler County in the Texas panhandle that

is connected to our Western Oklahoma processing complex. We completed the expansion of the Western Oklahoma natural gas processing plant in October 2011, which increased our processing capacity at the Western Oklahoma complex by 75 MMcf/d to a total of 235 MMcf/d. The gathering and processing expansions are supported by long-term agreements with producer customers.

Approximately 70% of our Oklahoma volumes result from contracts with 3 producers in 2011. We sell substantially all of the NGLs produced in the Western Oklahoma processing complex to ONEOK Hydrocarbon L.P. (“ONEOK”) under a long-term contract. Such sales represent approximately 13.2% of our consolidated revenue in 2011. The initial term of the ONEOK agreement expires in October 2021.

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. We plan to complete an additional interconnect with the NGPL Pipeline in Bennington, Oklahoma in April 2012. 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

- *Kentucky and southern West Virginia.* Our Northeast segment assets include the Kenova, Boldman, Cobb, Kermit and Langley (acquired in the first quarter of 2011) natural gas processing plants, an NGL pipeline and the Siloam NGL fractionation plant. In connection with the acquisition of the Langley processing plants, related facilities, and partially completed Ranger pipeline, we completed the construction of the Ranger Pipeline to extend our existing NGL pipeline and connect the Langley Processing Facilities to our Siloam fractionation facility. We also plan to complete an additional cryogenic natural gas processing plant with a capacity of 150 MMcf/d by the fourth quarter of 2012. In addition, we have two caverns for storing propane at our Siloam facility and additional propane storage capacity under a long-term firm-capacity agreement with a third party. The Northeast segment operations include fractionation and marketing services on behalf of the Liberty segment through the end of the third quarter 2011. Including our presence in the Marcellus shale (see *Liberty Segment* below), we are the largest processor and fractionator of natural gas in the Northeast, with fully integrated processing, fractionation, storage and marketing operations.
- *Michigan.* We own and operate a FERC-regulated crude oil pipeline in Michigan (“Michigan Crude Pipeline”) providing transportation service for three shippers.

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

Liberty Segment

- *Marcellus Shale.* We provide extensive natural gas midstream services in southwestern Pennsylvania and northern West Virginia through MarkWest Liberty Midstream. With gathering capacity of 325 MMcf/d and current processing capacity of 625 MMcf/d, we are the largest processor of natural gas in the Marcellus Shale, with fully integrated gathering, processing, fractionation, storage and marketing operations that are critical to the liquids-rich gas development in the northeast United States.

The processing and fractionation facilities currently operating and under construction in our Liberty segment include the following:

Processing

- 355 MMcf/d of current cryogenic processing capacity at our Houston Complex, which includes a 200 MMcf/d cryogenic plant that began operations in the second quarter of 2011.
- 270 MMcf/d of current cryogenic processing capacity at our Majorsville Complex, which includes a 135 MMcf/d cryogenic plant that began operations in the second quarter of 2011.
- 400 MMcf/d expansion of our Majorsville Complex, expected to commence operation in 2013, bringing our total cryogenic processing capacity at Majorsville to 670 MMcf/d. The Majorsville expansion includes two, 200 MMcf/d processing trains that are and will be supported by long-term agreements with CONSOL Energy, Noble Energy and Range Resources.
- 320 MMcf/d cryogenic processing capacity under construction in Mobley, West Virginia (“Mobley Complex”) where cryogenic plants with capacity of 120 MMcf/d and 200 MMcf/d are expected to be completed in the first and second half of 2012, respectively.
- 200 MMcf/d cryogenic processing capacity under construction at our Sherwood Complex that is expected to be completed in the second half of 2012. We recently announced plans to expand the capacity at our Sherwood Complex with an additional 200 MMcf/d cryogenic processing plant that is expected to be completed in 2013. The expansion plans are based, in part, on a producer customer’s decision to support the additional capacity under a long-term processing agreement. The producer customer has publicly stated its intent to move forward with the project but must make its final decision on whether to proceed with the additional plant at the Sherwood Complex by July 1, 2012.

By the end of 2013, MarkWest Liberty Midstream is expected to have between 1.5 Bcf/d and 1.7 Bcf/d of cryogenic processing capacity that is supported by long-term agreements with our producer customers. NGLs produced at the Majorsville Complex are delivered through an NGL pipeline (“Majorsville Pipeline”) to the Houston Complex for exchange for fractionated products. We also plan to complete an NGL pipeline connecting each of the planned processing facilities to the Majorsville Pipeline allowing for fractionation at the Houston Complex. By the end of 2012, MarkWest Liberty Midstream expects to have approximately 100 miles of NGL transportation pipeline.

Fractionation and Market Outlets

- Existing fractionation facility at our Houston Complex with a design capacity of 60,000 Bbl/d that was placed into service in the third quarter of 2011. Prior to the completion of the Houston fractionation facility, only propane was recovered at our Houston Complex and further fractionation of the remaining portion of the NGL stream produced at the Liberty processing plants was performed at the Siloam NGL fractionation plant in our Northeast segment.
- Existing interconnect with a key interstate pipeline providing a market outlet for the propane produced from this region.
- Existing extension of our Majorsville Pipeline to receive NGLs produced at a third-party's Fort Beeler processing plant. This project allows certain producers to benefit from our integrated NGL fractionation and marketing operations.
- Railcar loading facility under construction at our Houston Complex that is expected to be completed in the first half of 2012.

We continue to evaluate additional projects to expand our gathering, processing, fractionation and marketing operations in the Marcellus Shale.

Ethane Recovery and Associated Market Outlets

Due to the increased production of natural gas from the liquids-rich area of the Marcellus Shale, natural gas processors must begin to recover a significant amount of ethane from the raw NGL stream to continue to meet the pipeline gas quality specifications for residue gas. We have been developing a solution that will have the capability to recover and fractionate the required ethane, be scalable to recover and fractionate additional ethane at the option of our producer customers and provide access to attractive ethane markets in North America and Europe. The primary components of our ethane recovery solution consist of the following:

- 75,000 Bbl/d de-ethanization facilities under construction at our Houston and Majorsville Complexes that are expected to be completed by mid-2013.
- A third de-ethanization facility is planned that would increase production capacity of purity ethane to 115,000 Bbl/d by 2014.
- A joint pipeline project with Sunoco Logistics, L.P. ("Sunoco") that is currently under construction to deliver Marcellus ethane to Sarnia, Ontario, Canada markets ("Mariner West"). Mariner West will utilize new and existing pipelines and is anticipated to have an initial capacity to transport up to 50,000 Bbl/d of ethane by mid-2013 with the ability to expand to support higher volumes as needed. Sunoco completed an open season for Mariner West and received binding commitments from shippers that would enable the project to proceed as designed.
- An additional joint project with Sunoco is under consideration ("Mariner East"). Mariner East, a pipeline and marine project, is intended to deliver Marcellus purity ethane to the Gulf Coast and international markets. Mariner East is anticipated to have initial capacity to transport up to 50,000 Bbl/d of ethane.

We continue to evaluate additional projects that would support a comprehensive ethane solution for producers in the Marcellus Shale.

The majority of the volumes currently 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.

Utica Segment

Effective January 1, 2012, MarkWest and EMG formed MarkWest Utica EMG, a joint venture focused on the development of significant natural gas processing and NGL fractionation, transportation and marketing infrastructure to serve producers' drilling programs in the Utica shale in eastern Ohio. The first phase of the Utica development plan includes two new processing complexes and a 100,000 Bbl/d fractionation, storage, and marketing facility. The initial processing complex will be in Harrison County ("Harrison Complex"), and is expected to begin initial operations in mid-2013. MarkWest is finalizing the design capacity and the location of the second processing complex, which is also expected to begin operations in 2013.

Both processing complexes are expected to be connected via an NGL pipeline system to the fractionation facilities at the Harrison Complex that is expected to be operational in 2013. Creating a large network of processing complexes connected through an extensive NGL gathering system has been critical to the full development of the Marcellus, and the announced Ohio facilities represent the first major step in providing Utica producers with the same benefits. Additionally, the Harrison Complex fractionation facilities, which would be able to market NGLs by truck, rail and pipeline, is expected to be connected to our extensive processing and NGL pipeline network in our Liberty segment and provide for the integrated operation of the two largest fractionation complexes in the Northeastern United States.

The Utica Segment did not have any assets, liabilities, equity or operations as of, or for the year ending, December 31, 2011. As such, it is not considered a reportable segment as described in Note 24 of the accompanying Notes to the 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 SMR (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 is 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 *Non-GAAP Measures* discussion below) generated by our assets, by segment, for the year ended December 31, 2011:

	<u>Southwest</u>	<u>Northeast</u>	<u>Liberty</u>	<u>Gulf Coast</u>	<u>Total</u>
Revenue	60%	17%	16%	7%	100%
Net operating margin	49%	20%	19%	12%	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, a joint venture with Cardinal Midstream, LLC (“Cardinal”) that is accounted for using the equity method. Centrahoma owns certain processing plants in the Arkoma Basin and Cardinal operates an additional processing plant that is not owned by Centrahoma but is located adjacent to and operates in conjunction with the Centrahoma plants. We have signed long-term agreements to dedicate the processing rights for our natural gas gathering system in the Woodford Shale to Centrahoma and to Cardinal’s independently owned processing facility. 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 *Non-GAAP Measures* below for discussion and reconciliation of net operating margin) from natural gas gathering, transportation and processing; NGL transportation, fractionation, exchange, 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, exchange, marketing 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 (i) a percentage discount to a specified index price, (ii) a specified index price less a fixed amount or (iii) 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 (i) and (iii) 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 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 may influence our long-term financial results.

Non-GAAP Measures

In evaluating the Partnership's financial performance, management utilizes the segment performance measures, segment revenues and operating income before items not allocated to segments. These financial measures are presented in Note 24 to the accompanying condensed consolidated financial statements and are considered non-GAAP financial measures when presented outside of the notes to the condensed consolidated financial statements. The use of these measures allows investors to understand how management evaluates financial performance to make operating decisions and allocate resources. See Note 24 to the accompanying condensed consolidated financial statements for the reconciliations of segment revenue and operating income before items not allocated to segments to the respective most comparable GAAP measure.

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 of net operating margin to income (loss) from operations, the most comparable GAAP financial measure of this non-GAAP financial measure (in thousands):

	Year ended December 31,		
	2011	2010	2009
Segment revenue	\$1,549,819	\$1,241,563	\$ 858,635
Purchased product costs	(682,370)	(578,627)	(408,826)
Net operating margin	867,449	662,936	449,809
Facility expenses	(173,598)	(151,449)	(126,977)
Derivative loss	(75,515)	(80,350)	(188,862)
Revenue deferral adjustment	(15,385)	—	—
Selling, general and administrative expenses	(81,229)	(75,258)	(63,728)
Depreciation	(149,954)	(123,198)	(95,537)
Amortization of intangible assets	(43,617)	(40,833)	(40,831)
Loss on disposal of property, plant and equipment	(8,797)	(3,149)	(1,677)
Accretion of asset retirement obligations	(1,190)	(237)	(198)
Impairment of goodwill and long-lived assets	—	—	(5,855)
Income (loss) from operations	<u>\$ 318,164</u>	<u>\$ 188,462</u>	<u>\$ (73,856)</u>

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, 2011, we calculated the following approximate percentages of our revenue and net operating margin from the following types of contracts:

	<u>Fee-Based</u>	<u>Percent-of-Proceeds(1)</u>	<u>Percent-of-Index(2)</u>	<u>Keep-Whole(3)</u>	<u>Total</u>
Revenue	21%	38%	4%	37%	100%
Net operating margin(4)	38%	29%	0%	33%	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 gathering 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 to purchase our natural gas and NGLs is based primarily on price, delivery capabilities, flexibility and maintenance of high-quality customer relationships.

Our competitors include:

- a large number of natural gas midstream providers, of varying financial resources and experience, 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

Some of our competitors operate as master limited partnerships and may 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 contracted 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, are located primarily in the heart of shale plays with significant growth opportunities 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 as the largest processor and fractionator in the region and our existing presence in the Appalachian Basin provide a significant competitive advantage. In the Liberty segment, our early entrance in the liquids-rich corridor of 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 and the development of the Utica 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 may counteract this seasonality impact.

Regulatory Matters

Our operations are subject to extensive regulations. The failure to comply with applicable laws and regulations or to obtain, maintain and comply with requisite permits and authorizations can result in substantial penalties and other costs to the Partnership. 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 Natural 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, and it is possible that we may construct additional gas pipelines in the future that may be subject to such regulation. Federal regulation extends to various matters including:

- rates and rate structures;
- return on equity;
- recovery of costs;
- the services that our regulated assets are permitted to perform;
- the acquisition, construction, expansion, operation and disposition of assets;
- Affiliate interactions; 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 FERC regulated natural gas facilities from unduly preferring, or unduly discriminating against, any person with respect to pipeline rates or terms and conditions of service or other matters. 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 be assured that FERC will continue to pursue its approach of pro-competitive 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 EAct”). Under the 2005 EAct, 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 EAct 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 EAct. This order makes it unlawful for gas pipelines and storage companies that provide interstate services to: (i) directly or indirectly, to use or employ any device, scheme or artifice to defraud 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; (ii) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (iii) 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.

Standards of Conduct. On October 16, 2008, FERC issued new standards of conduct for transmission providers (Order 717) to regulate the manner in which interstate natural gas pipelines may interact with their marketing affiliates based on an employee separation approach. A “Transmission Provider” includes an interstate natural gas pipeline that provides open access transportation pursuant to FERC’s regulations. Under these rules, a Transmission Provider’s transmission function employees (including the transmission function employees of any of its affiliates) must function independently from the Transmission Provider’s marketing function employees (including the marketing function employees of any of its affiliates). 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 a rehearing order, Order 717-B, on November 16, 2009, in Order 717-C, on April 16, 2010, and in Order 717-D, on April 8, 2011. However, Orders 717-B, 717-C, and 717-D did not substantively alter the rules promulgated under Orders 717 and 717-A.

Market Transparency Rulemakings. In 2007, FERC issued Order 704, whereby 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 requires most, if not all of our natural gas pipelines to report annual volumes of relevant transactions to FERC.

Intrastate Natural Gas Pipeline Regulation. Some of our intrastate gas pipeline facilities are subject to various state laws and regulation that affect the rates we charge and terms of service. Although state regulation is typically less onerous than FERC, state regulation typically requires pipelines to charge just and reasonable rates and to provide service on a non-discriminatory basis. The rates and service of an intrastate pipeline generally are subject to challenge by complaint.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such FERC action materially differently than other midstream natural gas companies with whom we compete.

Natural Gas Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC if the primary function of the facilities is gathering natural gas. We own a number of facilities 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 or regulated as a public utility. Our gathering operations also may be or become subject to safety and operational regulations and permitting relating to the design, siting, 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 Gathering Pipelines. Several of our NGL gathering pipelines carry NGLs across state lines; however, we do not operate these pipelines as common carrier pipelines or hold them out for service to the public because there are no third-party shippers on the pipelines and we do not expect third-party shippers to seek to use these NGL pipelines. Accordingly, we believe these pipelines would meet the qualifications for a waiver from FERC's applicable regulatory requirements. We cannot, however, 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 determine that these NGL pipelines would not qualify for a waiver from FERC's applicable regulatory requirements, we would likely 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. We also may elect to construct one or more common carrier NGL product pipelines to transport NGL products for third-party shippers across state lines or otherwise in interstate commerce, in which event we would be required to comply with FERC requirements for such common carrier pipelines, including the filing of a tariff. Our NGL pipelines are subject to safety regulation by the Department of Transportation under 49 C.F.R. Part 195 for operators of hazardous liquid pipelines. Our NGL gathering pipelines and operations may also be or become subject to state public utility or related jurisdiction which could impose additional safety and operational regulations relating to the design, siting, installation, testing, construction, operation, replacement and management of NGL gathering facilities.

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.

Common Carrier Crude 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. On July 1, 2011, the Court denied our petition for review of the FERC’s decision.

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. On July 25, 2011, the parties submitted an offer of settlement to FERC in this proceeding and on December 16, 2011, FERC issued an order accepting that settlement. MarkWest began charging the settlement rates effective August 1, 2011 and expects to pay refunds related to the initial filing once the FERC’s December 2011 order becomes final and is no longer subject to appeal.

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 environmentally sensitive areas such as wetlands 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 assure, 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 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, permits and permitting

requirements, or remediation pursuant to such laws and regulations, 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. Such revised or additional environmental requirements may also result in material delays in the construction or expansion of our facilities, which may materially impact our ability to meet our construction obligations with our producer customers.

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. Under the authority of the EPA, most states administer some or all of the provisions of the RCRA, sometimes in conjunction with their own, more stringent requirements. 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, storage, 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 nonhazardous 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 Third Parties.

The prior third-party owner or operator of our Cobb, Boldman, Kenova, and Majorsville facilities, who is also the prior owner and current operator of the Kermit facility, 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 third-party owner/operator with the Kentucky Natural Resources and Environmental Protection Cabinet in October 1994. The third party 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 third party 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.

In addition, the prior third-party owner and/or operator of certain facilities on the real property on which our rail facility is being constructed near Houston, Pennsylvania has been, or is currently involved in, investigatory or remedial activities related to acid mine drainage (“AMD”) with respect to the real property underlying these facilities. These investigatory and remedial obligations arise out of an arrangement entered into between the Pennsylvania Department of Environmental Protection and the third party, which has accepted liability and responsibility for, and indemnifies us against, any environmental liabilities associated with the AMD that are not exacerbated by us in connection with our operations. In addition, the third party has agreed to perform all of the required response actions at its expense in a manner that minimizes interference with our use of the property. 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 Discharges.

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 various states. We believe that we are in substantial compliance with the Clean Water Act and analogous state laws. However, new permitting requirements or reinterpretations of existing requirements may be implemented that could materially increase our operating costs or materially delay the construction or expansion of our facilities.

Hydraulic Fracturing.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and additives under pressure into the formation to fracture the surrounding rock and stimulate production. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act, as amended (“SDWA”) over certain hydraulic fracturing activities involving the use of diesel fuel. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have already adopted laws and/or regulation that require disclosure of the chemicals used in hydraulic fracturing and many states are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on natural gas drilling activities. In the event that new or more stringent federal, state or local legal restrictions relating to natural gas drilling activities or to the hydraulic fracturing process are adopted in areas where our producer customers operate, those customers could incur potentially significant added costs to comply with such requirements and experience delays or curtailment in the pursuit of production or development activities, which could reduce demand for our gathering, transportation and processing services and/or our NGL fractionation services.

In addition, certain governmental reviews are either underway or being proposed that focus on potential environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the U.S. House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms, which events could delay or curtail production of natural gas, and thus reduce demand for our midstream services.

Air Emissions.

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 aggregate two or more of our facilities into one application 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 or operational delays while applying for, or awaiting the review, processing and issuance of new or amended permits. For example, on July 28, 2011, the EPA proposed a range of new regulations that would establish new air emission controls for oil and natural gas production and natural gas processing, including, among other things, new leak detection requirements for natural gas processing plants. The EPA is under a court order to finalize these proposed regulations by April 3, 2012. We have been in discussions with various state agencies in the areas in which 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.

Climate Change.

As a consequence to an EPA administrative conclusion that emissions of carbon dioxide, methane and other greenhouse gases, or GHGs, into the ambient air endangers public health and welfare, the EPA has adopted regulations that require a reduction in emissions of GHGs from motor vehicles and also trigger construction and operating permit review for GHG emissions from certain large 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. In addition, the EPA adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified greenhouse gas emission sources in the United States, including, among others, certain onshore and offshore oil and natural gas production and onshore oil and natural gas processing, fractionation, transmission, storage and distribution facilities, which may include certain of our operations. 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 potentially significant added costs to comply with the new regulatory requirements or added capital expenditures for air pollution control equipment, or we experience delays or possible curtailment of construction or projects in connection with maintaining or in applying or obtaining preconstruction and operating permits and we may encounter limitations to the design capacities or size of facilities as a result of the requirements and consequences of the EPA GHG regulations.

In addition to the EPA regulations, 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. 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 potentially significant added costs to comply with the new regulatory requirements or to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas. 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. Finally, for a variety of reasons, natural and/or anthropogenic, climate changes could occur and have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events; if such effects were to occur, they could have an adverse effect on our operations, 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 were 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.

Endangered Species Act Considerations.

The federal Endangered Species Act (“ESA”) restricts activities that may affect endangered or threatened species or their habitats. If endangered species are located in areas where we propose to construct new gathering or transportation pipelines or processing or fractionation facilities, such work could be prohibited or delayed or expensive mitigation may be required. Additionally, construction and operational activities could result in inadvertent impact to habitats of listed species and could result in alleged takings under the ESA, exposing the Partnership to civil or criminal enforcement actions and fines or penalties. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia on September 9, 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA over the next six years, through the agency’s 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where we conduct operations or plan to construct pipelines or facilities could cause us to incur increased costs arising from species protection measures or could result in limitations on our customer’s exploration and production activities, which could have an adverse impact on demand for our midstream operations.

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 (“HLPESA”), with respect to crude oil, NGLs and condensates. The NGPSA and HLPESA govern the design, installation, testing, construction, operation, replacement and management of natural gas, oil and NGL pipeline facilities. The NGPSA and HLPESA 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 HLPESA requirements; however, these laws are subject to further amendment, with the potential for more

onerous obligations and stringent standards being imposed on pipeline owners and operators. For example, on January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (“2011 Pipeline Safety Act”), which requires increased safety measures for gas and hazardous liquids transportation pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use and leak detection system installation. The 2011 Pipeline Safety Act also directs owners and operators of interstate and intrastate gas transmission pipelines to verify their records confirming the maximum allowable pressure of pipelines in certain class locations and high consequence areas, requires promulgation of regulations for conducting tests to confirm the material strength of pipe operating above 30% of specified minimum yield strength in high consequence areas and increases the maximum penalty for violation of pipeline safety regulations from \$1 million to \$2 million. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could be significant and have a material adverse effect on our results of operations or financial position.

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 has adopted rules that amend the pipeline safety regulations to extend regulatory coverage to certain rural onshore hazardous liquid gathering lines and low stress pipelines, including those pipelines located in 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. For instance, in August 2011, PHMSA published an advance notice of proposed rulemaking in which the agency is seeking public comment on a number of changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, (i) revising the definitions of “high consequence areas” and “gathering lines”; (ii) strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed; (iii) strengthening requirements on the types of gas transmission pipeline integrity assessment methods that may be selected for use by operators; (iv) imposing gas transmission integrity management requirements on onshore gas gathering lines; (v) requiring the submission of annual, incident and safety-related conditions reports by operators of all gathering lines; and (vi) enhancing the current requirements for internal corrosion control of gathering lines.

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 683 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 flow, 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 other than MarkWest Liberty Midstream, but 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 and our indentures contain 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 our 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 may 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 available for distribution may 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 2010 ranged from a high of \$6.01 per MMBtu to a low of \$3.29 per MMBtu. In 2011, the same index ranged from a high of \$4.85 per MMBtu to a low of \$2.99 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 2010 ranged from a high of approximately \$1.55 per gallon to a low of approximately \$1.11 per gallon. In 2011, the same composite ranged from a high of approximately \$2.18 per gallon to a low of approximately \$1.51 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 NGL 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.

Additionally, due to the timing of purchases and sales of natural gas and NGLs, direct exposure to changes in market prices of either gas or NGLs can be created because there is no longer an offsetting purchase or sale that remains exposed to market pricing. Direct exposure may occur naturally as result of our production processes or we may create exposure through purchases of NGLs or natural gas. Given that we have derivative positions, adverse movement in prices to the positions we have taken may 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 expect to 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 of 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 risk management 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 and promulgation of regulations thereunder, could have an adverse impact on our ability to manage 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 on July 21, 2010 and requires the Commodities Futures Trading Commission (the “CFTC”), the SEC and other regulators to promulgate rules and regulations implementing the new legislation. The agencies have taken administrative action to defer the effectiveness of the Dodd-Frank Act as they continue to work on finalizing rules. The CFTC has also proposed a phased implementation in which entities such as the Partnership will have a further deferred compliance date. Among the regulations the CFTC has finalized are regulations to set aggregate federal position limits for futures and option contracts for crude oil, natural gas, heating oil and gasoline and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. This regulation will be effective for “spot months” 60 days after the definition of the term “Swap” is finalized and for “all months” after the CFTC obtains approximately one year’s data for swap open interest in such contracts. While it is not possible at this time to predict when the CFTC and the SEC will finalize or make these regulations effective, the agencies have issued estimated timeframes which indicate that significant elements of the regulations will be addressed in the first half of 2012. The financial reform regulations may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities either through direct regulation of us or indirectly through regulation of our derivative counterparties, although the specifics of those provisions are uncertain at this time. The financial reform legislation also requires 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 2011, we saw decreases in the prices of natural gas, leading some producers to announce significant reductions to their drilling plans specifically in dry gas areas. If sustained over the long-term, low gas prices could lead to a material reduction in volumes in certain areas of our operations.

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.

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 or NGL supplies may not be available upon completion of the facilities.

One of the ways we intend to grow our business is through the construction of, or additions to, our existing, gathering, treating, processing, and fractionation facilities. The construction of gathering, processing, fractionation 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, and stringent, lengthy and occasionally unreasonable or impractical federal, state and local permitting, consent, or authorizations requirements, which may cause us to incur additional capital expenditures for meeting certain conditions or requirements or which may delay, interfere with or impair our construction activities. As a result, new facilities may not be

constructed as scheduled or as originally designed, which may require redesign and additional equipment, relocations of facilities or rerouting of pipelines, which in turn could subject us to additional capital costs, additional expenses or penalties and may adversely affect our operations and cash flows available for distribution to unitholders. In addition, the coordination and monitoring of this diverse group of projects requires skilled and experienced labor. 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 and terminate their contracts with us if construction deadlines are not achieved. Any such penalty or contract termination could have a material adverse effect on our income from operations, cash flows and quarterly distribution to common unitholders. 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 may occur over an extended period of time, and we may not receive any material increases in revenues until after completion of the project, if at all. Our ability to successfully manage these projects depends on obtaining skilled labor, project managers and engineers.

Furthermore, we may have only limited natural gas or NGL supplies committed to these facilities prior to their construction. Moreover, we may construct facilities to capture anticipated future growth in production or satisfy anticipated market demand in a region in which anticipated production growth or market demand does not materialize, the facilities may not operate as planned or may not be used at all. 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 or NGLs 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, or 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, which risks may increase during periods of economic uncertainty. 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 risk management 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 risk management 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, NGL and crude oil transmission operations are or may in the future be, subject to siting, public necessity, rate and service regulations by FERC or various state regulatory bodies, depending upon jurisdiction. FERC generally regulates the transportation of natural gas, NGLs 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 or are constructing pipelines that are carrying or are expected to carry NGLs owned by us across state lines. We currently are, and expect in the future to be, the only shipper on these pipelines and do not operate, and do not expect in the future to operate, these pipelines as a common carrier or hold them out for service to the public. We do not expect third-party entities to seek to utilize our NGL pipelines; therefore, we believe these pipelines would meet the qualifications for a waiver from FERC's applicable regulatory requirements. 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. We may also elect to construct in the future NGL common carrier pipelines to carry NGLs of third parties across state lines or otherwise in interstate commerce, and in such event we would be required to comply with FERC rate, operational, reporting and other requirements which may increase our cost of operations.

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 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, NGL 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 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 may 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 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 and current operator of our Kermit facility. 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.

In addition, Consol Coal is the previous owner and/or operator of certain facilities on the real property on which our rail facility is being constructed near Houston, Pennsylvania, and has been or is currently involved in, investigatory or remedial activities related to AMD with respect to the real property underlying these facilities. Consol Coal has accepted liability and responsibility for, and has agreed to indemnify us against, any environmental liabilities associated with the AMD that are not exacerbated by us in connection with our operations.

Our results of operation and our ability to make cash distributions to our unitholders could be adversely affected if in the future either Columbia Gas or Consol Coal fails to perform under the indemnification provisions of which we are the beneficiary.

Our business is subject to laws and regulations with respect to environmental, occupational, safety, nuisance, zoning, land use 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, occupational, safety, nuisance, zoning, land use, 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 CERCLA, RCRA, 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, and new, amended or re-interpreted permitting requirements and processes, might adversely affect 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. For example, certain requirements under amendments, expansions or re-interpretations of existing laws may include more stringent permitting requirements if two or more of our facilities are aggregated into one application 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 health and the environment, the EPA has adopted regulations that require a reduction in emissions of GHGs from motor vehicles and also trigger PSD and Title V permit requirements for GHG emissions from certain large 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. Also, the EPA adopted rules regulating the monitoring and reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including, among others, certain natural onshore and offshore oil and natural gas production and onshore oil and natural gas processing, fractionation, transmission, storage and distribution facilities. 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 materially 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, for a variety of reasons, natural and/or anthropogenic, climate changes could occur which could 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, which in turn could adversely affect our cash available for distribution to our unitholders.

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, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. Also, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices, with the EPA commencing a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014 and, more recently, announcing the proposed development of effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. Moreover, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. 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 of natural gas that we gather and process and NGLs that we gather 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 may 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 and fractionation facilities. Likewise, if the pipelines into which we deliver NGLs or crude oil are interrupted, we may be limited in, or prevented from conducting, our crude oil or NGL 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 (i) the volumes of natural gas we process, gather and transmit, (ii) the throughput of NGLs through our transportation, fractionation and storage facilities and (iii) 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, various means of transportation and marketing services. 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, or to market the natural gas or NGL's, 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;
- 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 NGL pipelines and fractionation facilities; and
- inadequate storage capacity or market access to support production volumes.

In addition, the construction and operation of certain of our facilities in our Northeast and Liberty segments may be impacted by subsurface mining operations. One or more third parties may have previously engaged in, or may in the future engage in, subsurface mining operations near or under our facilities, which could cause subsidence or other damage to our facilities. In such event, our operations at such facilities may be impaired or interrupted, and we may not be able to recover the costs incurred to repair our facilities from such third parties.

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.

Alternative financing strategies may not be successful.

Periodically, we may consider the use of alternative financing strategies such as joint venture arrangements and the sale of non-strategic assets. Joint venture arrangements 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 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 vehicles and construction and farm equipment;
- leakage of crude oil, natural gas, NGLs and other hydrocarbons into the environment, including groundwater;
- 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, field 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 (i) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (ii) unable to obtain financing for these acquisitions on economically acceptable terms, or (iii) outbid by competitors, then our future growth and ability to increase distributions may 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 may 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 may 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 Pioneer, MarkWest Utica EMG, 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 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, IFRS, could change our current application of GAAP. Changes in the application of GAAP and the costs of implementing such changes could result 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 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 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 would 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 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 may be reduced to reflect the impact of that law on us.

If we were subjected to a material amount of additional entity-level taxation or other fees 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 or fees imposed 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, use, property, ad valorem and other forms of taxation or permit, impact, throughput and miscellaneous other fees. Imposition of any such taxes or fees may substantially reduce the cash available for distribution to our unitholders. For example, the state of Texas has instituted an income-based tax that results in an entity level tax for us. We are required to pay a Texas franchise tax of 1.0% of our gross margin that is apportioned to Texas in the prior year. The imposition of entity level taxes on us by any other state may 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, 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 and Class B 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 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, the Class A unitholders and Class B 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 facilities, natural gas gathering systems, NGL pipelines, natural gas pipeline and crude oil pipeline as of and for the year ended December 31, 2011.

Gas Processing Facilities:

Facility	Location	Year of Initial Construction	Design Throughput Capacity (Mcf/d)	Year ended December 31, 2011		
				Natural Gas Throughput (Mcf/d)	Utilization of Design Capacity	NGL Throughput (Gal/d)
Southwest						
<i>East Texas:</i>						
East Texas processing plant	Panola County, TX	2005	280,000	228,300	82%	654,000
<i>Oklahoma:</i>						
Western Oklahoma processing plants(1)	Custer County, OK	2000	235,000	175,500	75%	485,500
Northeast						
<i>Appalachia:</i>						
Kenova processing plant(2)	Wayne County, WV	1996	160,000	99,200	62%	195,900
Boldman processing plant(2)	Pike County, KY	1991	70,000	41,600	59%	47,300
Cobb processing plant	Kanawha County, WV	2005	65,000	31,900	49%	74,300
Kermit processing plant(2)(3)	Mingo County, WV	2001	32,000	N/A	N/A	N/A
Langley processing plant(4)	Langley, KY	2000	175,000	133,200	76%	357,000
Liberty						
<i>Marcellus Shale:</i>						
Houston processing plants(5)	Washington County, PA	2009	355,000	176,300	50%	395,400
Majorsville processing plant(6)	Marshall County, WV	2010	270,000	147,600	55%	300,600
Gulf Coast						
Javelina processing plant(7)	Corpus Christi, TX	1989	142,000	113,300	80%	892,300

- (1) A 75 MMcf/d cryogenic plant began operations in the fourth quarter of 2011, increasing the processing capacity.
- (2) 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.
- (3) 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.
- (4) The Langley processing plant was acquired February 1, 2011 (see Note 3 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K). The volume reported is the average daily rate for the days of operation.
- (5) A 200 MMcf/d cryogenic plant began operations in the second quarter of 2011, increasing the processing capacity.
- (6) A 135 MMcf/d cryogenic plant began operations in the second quarter of 2011, increasing the processing capacity.
- (7) Also includes fractionation capacity of 29,000 Bbl/d.

Fractionation Facilities:

<u>Facility</u>	<u>Location</u>	<u>Year of Initial Construction</u>	<u>Design Throughput Capacity (Bbl/d)</u>	<u>Year ended December 31, 2011</u>	
				<u>NGL Throughput (Bbl/d)</u>	<u>Utilization of Design Capacity</u>
Northeast					
<i>Appalachia:</i>					
Siloam fractionation plant	South Shore, KY	1957	24,000	20,300	85%
Liberty					
<i>Marcellus Shale:</i>					
Houston(8)	Washington County, PA	2009	60,000	11,800	20%

(8) The fractionation facility at our Houston Complex was placed into service during the third quarter of 2011. Prior to the completion of the Houston fractionation facility, only propane was recovered and further fractionation of the remaining portion of the NGL stream was performed at the Siloam fractionation plant.

Our Siloam facility has both above ground, pressurized NGL 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. Our Houston facility has above ground NGL storage with a usable capacity of 3.8 million gallons and eight automated truck loading and unloading slots. We also have an additional 50 million gallons of NGL storage capacity that can be utilized by our Northeast and Liberty segments under a firm capacity agreement with a third party that expires 2018.

Natural Gas Gathering Systems:

Facility	Location	Year of Initial Construction	Design Throughput Capacity (Mcf/d)	Year ended December 31, 2011	
				Natural Gas Throughput (Mcf/d)	Utilization of Design Capacity
Southwest					
<i>East Texas:</i>					
East Texas gathering system	Panola County, TX	1990	500,000	423,600	85%
<i>Oklahoma:</i>					
Western Oklahoma gathering system	Wheeler County, TX and Roger Mills, Ellis, Custer and Beckham Counties, OK	1998	405,000	237,900	59%
Southeast Oklahoma gathering system	Hughes, Pittsburg and Coal Counties, OK	2006	550,000	511,900	93%
<i>Other Southwest:</i>					
Other Southwest gathering systems(9)	Various	Various	121,500	29,900	25%
Liberty					
<i>Marcellus Shale:</i>					
Gas gathering system	Washington County, PA	2008	325,000	245,700	76%

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

NGL Pipelines:

Pipeline	Location	Year of Initial Construction	Design Throughput Capacity (Bbl/d)	Year ended December 31, 2011	
				NGL Throughput (Bbl/d)	Utilization of Design Capacity
Northeast					
<i>Appalachia:</i>					
Langley to Siloam(10)	Langley, KY to South Shore, KY	1957	19,000	12,600	66%
Southwest					
<i>East Texas:</i>					
East Texas liquid line	Panola County, TX	2005	25,000	15,600	62%
Liberty					
<i>Marcellus Shale:</i>					
Majorsville to Houston	Washington County, PA	2010	43,400	7,200	17%
Fort Beeler to Majorsville(11)	Marshall County, WV to Washington County, PA	2011	45,000	1,700	4%

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

(11) The Fort Beeler to Majorsville pipeline was placed into service during the fourth quarter of 2011. The volume reported is the average daily rate for the days of operation.

Natural Gas Pipeline:

<u>Pipeline</u>	<u>Location</u>	<u>Year of Initial Construction</u>	<u>Design Throughput Capacity</u> (Dth/d)	<u>Year ended December 31, 2011</u>	
				<u>Natural Gas Throughput</u> (Dth/d)	<u>Utilization of Design Capacity</u>
Southwest					
<i>Oklahoma:</i>					
Arkoma Connector Pipeline(12)	Coal County, OK to Bryan County, OK	2009	638,000	271,400	43%

(12) 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:

<u>Pipeline</u>	<u>Location</u>	<u>Year of Initial Construction</u>	<u>Design Throughput Capacity</u> (Bbl/d)	<u>Year ended December 31, 2011</u>	
				<u>NGL Throughput</u> (Bbl/d)	<u>Utilization of Design Capacity</u>
Northeast					
<i>Michigan:</i>					
Michigan crude pipeline	Manistee County, MI to Crawford County, MI	1973	60,000	10,300	17%

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. Certain of our facilities, including our Siloam and Houston fractionation plants and several of our processing plants, 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, other than MarkWest Liberty Midstream, as collateral for borrowings under our Credit Facility.

ITEM 3. Legal Proceedings

We are subject to a variety of risks and disputes, and are a party to various legal and regulatory 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 be assured 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 and that none of these actions, either individually or in the aggregate, will have a material adverse effect on our financial condition, liquidity or results of operation.

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. In March 2011, MarkWest received an order assessing a penalty solely against Equitable for count one of the NOPV in the amount of \$0.5 million and assessing a penalty jointly and severally against MarkWest and Equitable for four of the other counts in the NOPV in the amount of \$0.2 million. In March 2011, the parties filed separate petitions for reconsideration. In January 2012, the Agency issued an order that dismissed the penalty assessed solely against Equitable but retained the \$0.2 million penalty assessed jointly and severally against MarkWest and Equitable. MarkWest did not appeal the Agency’s decision and paid the entire penalty.

ITEM 4. Mine Safety Disclosures

Not applicable.

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 2011 and 2010:

Quarter Ended	Unit Price		Distributions Per Common Unit	Declaration Date	Record Date	Payment Date
	High	Low				
December 31, 2011 . .	\$56.82	\$42.18	\$0.76	January 26, 2012	February 6, 2012	February 14, 2012
September 30, 2011. .	50.06	39.00	0.73	October 18, 2011	November 7, 2011	November 14, 2011
June 30, 2011	51.70	42.80	0.70	July 21, 2011	August 1, 2011	August 12, 2011
March 31, 2011	48.50	40.80	0.67	April 21, 2011	May 2, 2011	May 13, 2011
December 31, 2010 . .	43.51	35.70	0.65	January 27, 2011	February 7, 2011	February 14, 2011
September 30, 2010. .	37.00	31.50	0.64	October 27, 2010	November 8, 2010	November 12, 2010
June 30, 2010	33.45	20.96	0.64	July 22, 2010	August 2, 2010	August 13, 2010
March 31, 2010	32.00	26.05	0.64	April 22, 2010	May 3, 2010	May 14, 2010
December 31, 2009 . .	29.94	22.20	0.64	January 26, 2010	February 5, 2010	February 12, 2010

As of February 17, 2012, there were approximately 177 holders of record of our common units.

Distributions of Available Cash

Within 45 days after the end of each quarter, we distribute all of our “Available Cash” to unitholders of record on the applicable record date. We make distributions of “Available Cash” to all common and Class A unitholders, pro rata and we make distributions of Hydrocarbon Available Cash (as defined in our amended and restated partnership agreement) pro rata to common unitholders. Class B unitholders do not receive cash distributions. 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, which will include the holders of Class B units that convert upon liquidation, 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, 2011, regarding our common units that may be issued upon conversion of outstanding phantom units granted under all of our existing equity compensation plans that have been approved by security holders. There are no active plans that have not been approved by security holders.

	<u>Number of securities to be issued upon exercise of outstanding options, warrants and rights(1)</u>	<u>Weighted average exercise price of outstanding options, warrants and rights(2)</u>	<u>Number of securities remaining available for future issuance under equity compensation plans</u>
Equity compensation plans approved by security holders:			
2008 Long-Term Incentive Plan	935,509	\$—	858,438

(1) Includes 282,000 units that vest if we achieve various performance or market-based targets determined by the Compensation Committee of the Board. 141,000 of these performance based units vested in January 2012 and 141,000 units were forfeited.

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

Recent Sales of Unregistered Units

The Partnership issued approximately 19,954,000 Class B Units to EMG as part of our acquisition of the non-controlling interest in MarkWest Liberty Midstream which was effective December 31, 2011. See Note 4 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion of the acquisition of non-controlling interest.

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 (dollars in thousands, except per unit amounts). 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,				
	2011	2010	2009	2008	2007
Statement of Operations:					
Revenue:					
Revenue	\$1,534,434	\$1,241,563	\$ 858,635	\$1,060,662	\$ 845,727
Derivative (loss) gain(1)	(29,035)	(53,932)	(120,352)	277,828	(159,970)
Total revenue	<u>1,505,399</u>	<u>1,187,631</u>	<u>738,283</u>	<u>1,338,490</u>	<u>685,757</u>
Operating expenses:					
Purchased product costs	682,370	578,627	408,826	615,902	487,892
Derivative loss related to purchased product costs(1)	52,960	27,713	68,883	22,371	15,192
Facility expenses	173,598	151,449	126,977	103,682	70,863
Derivative (gain) loss related to facility expenses(1)	(6,480)	(1,295)	(373)	644	(14)
Selling, general and administrative expenses	81,229	75,258	63,728	68,975	72,484
Depreciation	149,954	123,198	95,537	67,480	41,281
Amortization of intangible assets	43,617	40,833	40,831	38,483	16,672
Loss on disposal of property, plant and equipment	8,797	3,149	1,677	178	7,743
Accretion of asset retirement obligations	1,190	237	198	129	114
Impairment of goodwill and long-lived assets	—	—	5,855	36,351	356
Total operating expenses	<u>1,187,235</u>	<u>999,169</u>	<u>812,139</u>	<u>954,195</u>	<u>712,583</u>
Income (loss) from operations	318,164	188,462	(73,856)	384,295	(26,826)
Other income (expense):					
(Loss) earnings from unconsolidated affiliates	(1,095)	1,562	3,505	90	5,309
Impairment of unconsolidated affiliate	—	—	—	(41,449)	—
Gain on sale of unconsolidated affiliate	—	—	6,801	—	—
Interest income	422	1,670	349	3,769	4,547
Interest expense	(113,631)	(103,873)	(87,419)	(64,563)	(39,435)
Amortization of deferred financing costs and discount (a component of interest expense)	(5,114)	(10,264)	(9,718)	(8,299)	(2,983)
Derivative gain related to interest expense(1)	—	1,871	2,509	—	—
Loss on redemption of debt	(78,996)	(46,326)	—	—	—
Miscellaneous income (expense), net(1)	144	1,189	2,459	(241)	233
Income (loss) before provision for income tax	119,894	34,291	(155,370)	273,602	(59,155)
Provision for income tax expense (benefit):					
Current	17,578	7,655	8,072	15,032	23,869
Deferred	(3,929)	(4,466)	(50,088)	53,798	(48,518)
Total provision for income tax	<u>13,649</u>	<u>3,189</u>	<u>(42,016)</u>	<u>68,830</u>	<u>(24,649)</u>
Net income (loss)	106,245	31,102	(113,354)	204,772	(34,506)
Net (income) loss attributable to non-controlling Interest	(45,550)	(30,635)	(5,314)	3,301	(4,853)
Net income (loss) attributable to the Partnership	<u>\$ 60,695</u>	<u>\$ 467</u>	<u>\$ (118,668)</u>	<u>\$ 208,073</u>	<u>\$ (39,359)</u>
Net income (loss) attributable to the Partnership's common unitholders per common unit(2)(3):					
Basic	<u>\$ 0.75</u>	<u>\$ (0.01)</u>	<u>\$ (1.97)</u>	<u>\$ 4.02</u>	<u>\$ (1.72)</u>
Diluted	<u>\$ 0.75</u>	<u>\$ (0.01)</u>	<u>\$ (1.97)</u>	<u>\$ 4.02</u>	<u>\$ (1.72)</u>
Cash distribution declared per common unit(3)	<u>\$ 2.750</u>	<u>\$ 2.560</u>	<u>\$ 2.560</u>	<u>\$ 2.059</u>	<u>\$ 0.703</u>

	Year ended December 31,				
	2011	2010	2009	2008	2007
Balance Sheet Data (at December 31):					
Working capital	\$ 4,234	\$ (43,296)	\$ 13,536	\$ 51,237	\$ 21,932
Property, plant and equipment, net	2,864,307	2,319,024	1,981,644	1,569,525	830,809
Total assets	4,070,425	3,333,362	3,014,737	2,673,054	1,524,695
Total long-term debt	1,846,062	1,273,434	1,170,072	1,172,965	552,695
Total equity	1,502,067	1,458,566	1,309,553	1,148,155	563,974
Cash Flow Data:					
Net cash flow provided by (used in):					
Operating activities	\$ 414,698	\$ 312,328	\$ 223,101	\$ 226,995	\$ 133,237
Investing activities	(776,553)	(485,936)	(461,753)	(909,265)	(314,792)
Financing activities	411,421	143,306	333,083	647,896	170,406
Other Financial Data:					
Maintenance capital expenditures(4)	\$ 16,067	\$ 10,286	\$ 7,483	\$ 7,161	\$ 4,140
Growth capital expenditures(4)	535,214	448,382	479,140	568,137	312,499
Total capital expenditures	\$ 551,281	\$ 458,668	\$ 486,623	\$ 575,298	\$ 316,639

- (1) As discussed further in Note 6 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,				
	2011	2010	2009	2008	2007
Realized (loss) gain—revenue	\$(48,093)	\$(33,560)	\$ 87,289	\$(15,704)	\$(15,901)
Unrealized gain (loss)—revenue	19,058	(20,372)	(207,641)	293,532	(144,069)
Realized (loss) gain—purchased product costs	(27,711)	(21,909)	(53,052)	7,368	(8,829)
Unrealized loss—purchased product costs	(25,249)	(5,804)	(15,831)	(29,739)	(6,363)
Unrealized gain (loss)—facility expenses	6,480	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	\$(75,515)	\$(78,289)	\$(186,017)	\$254,813	\$(175,148)

- (2) For the calculation of Net (loss) income attributable to the Partnership's common unitholders per common unit, see Note 23 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 give effect to the Merger.
- (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 investment.

Operating Data

	Year ended December 31,				
	2011	2010	2009	2008	2007
Southwest					
East Texas gathering systems throughput (Mcf/d)	423,600	430,300	454,400	442,900	413,700
East Texas natural gas processed (Mcf/d)	228,300	233,100	246,600	189,300	175,400
East Texas NGL sales (gallons, in thousands)	238,700	245,800	245,800	193,500	179,600
Western Oklahoma gathering system throughput (Mcf/d)(1)	237,900	191,100	185,600	193,500	116,500
Western Oklahoma natural gas processed (Mcf/d)	175,500	134,700	148,000	105,300	104,000
Western Oklahoma NGL sales (gallons, in thousands)	177,200	134,100	126,900	79,400	87,500
Southeast Oklahoma gathering systems throughput (Mcf/d)	511,900	521,400	416,800	318,700	114,000
Southeast Oklahoma natural gas processed (Mcf/d)(2)	103,400	81,600	39,400	46,300	6,300
Southeast Oklahoma NGL sales (gallons, in thousands)	125,100	102,300	48,400	31,000	900
Arkoma Connector Pipeline throughput (Mcf/d)(3)	307,300	375,900	277,300	N/A	N/A
Other Southwest gathering system throughput (Mcf/d)(4)	29,900	39,500	57,600	69,400	67,400
Northeast(5)					
Natural gas processed (Mcf/d)	305,900	188,700	194,600	202,200	200,200
NGLs fractionated (Bbl/d)(6)	20,300	20,700	18,300	12,400	10,800
Keep-whole sales (gallons, in thousands)	113,800	136,700	145,500	140,800	126,200
Percent-of-proceeds sales (gallons, in thousands)	130,300	120,300	99,900	54,000	43,800
Total NGL sales (gallons, in thousands)(7)	244,100	257,000	245,400	194,800	170,000
Crude oil transported for a fee (Bbl/d)	10,300	12,800	12,300	13,300	14,000
Liberty(8)					
Natural gas processed (Mcf/d)	323,900	215,700	51,800	18,700	N/A
Gathering system throughput (Mcf/d)	245,700	142,200	53,500	18,700	N/A
NGLs fractionated (Bbl/d)(9)	11,800	4,200	1,100	N/A	N/A
NGL sales (gallons, in thousands)(10)	241,200	119,900	34,400	N/A	N/A
Gulf Coast					
Refinery off-gas processed (Mcf/d)	113,300	118,600	120,200	122,900	114,500
Liquids fractionated (Bbl/d)	21,200	22,500	23,200	24,400	25,000
NGL sales (gallons excluding hydrogen, in thousands)	325,700	345,500	356,300	376,000	382,800

- (1) Includes natural gas gathered in Western Oklahoma and from the Granite Wash formation in the Texas Panhandle as management considers this one integrated area of operations.
- (2) The natural gas processing in Southeast Oklahoma is outsourced to Centrahoma, our equity investment, or other third-party processors.
- (3) The Arkoma Connector Pipeline was placed into service in July 2009. The volume reported is the average daily rate for the days of operation.
- (4) Excludes lateral pipelines where revenue is not based on throughput.
- (5) Includes throughput from the Kenova, Cobb, Boldman and Langley processing plants. We acquired the Langley processing plant in February 2011. The volumes reported are the average daily rates for the days of operation.

- (6) Amount includes 3,900 barrels per day, 4,000 barrels per day and 1,500 barrels per day fractionated on behalf of Liberty for 2011, 2010 and 2009, respectively. Beginning in the fourth quarter of 2011, Siloam no longer fractionates NGLs on behalf of Liberty due to the operation of Liberty's fractionation facility that began in September 2011.
- (7) Represents sales at the Siloam fractionator. The total sales exclude approximately 59,200,000 gallons, 60,900,000 gallons, and 23,300,000 gallons sold by the Northeast on behalf of Liberty for 2011, 2010 and 2009, respectively. These volumes are included as part of NGLs sold at Liberty.
- (8) The 2009 and 2008 volumes represent the average daily rate for the period of operation.
- (9) Amount includes all NGLs that were produced at the Liberty processing facilities and fractionated into purity products at our Liberty fractionation facility. Through August 2011, only propane was recovered at our Liberty facilities. In September 2011, Liberty's fractionation facility commenced operations and Liberty now has full fractionation capabilities.
- (10) Includes sale of all purity products fractionated at the Liberty facilities and sale of all unfractionated NGLs. Also includes the sale of purity products fractionated and sold at the Siloam facilities on behalf of Liberty.

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, 2011 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 \$143 million, or 30%, for the year ended December 31, 2011 compared to the same period in 2010. The increase is primarily due to higher commodity prices in 2011, expanding operations in the Liberty segment and increased volumes processed in the Southwest segment. The increase in segment income was partially offset by a \$20 million decrease in net cash flow from the settlement of commodity derivative positions.

- We acquired the remaining 49% interest in MarkWest Liberty Midstream effective December 31, 2011 for approximately \$998 million of cash, including transaction costs, and the issuance of approximately 19,954,000 unregistered Class B units valued at approximately \$753 million.
- We increased the borrowing capacity under our Credit Facility from \$705 million to \$900 million.
- We received net proceeds of approximately \$1.2 billion from public offerings of senior notes and redeemed \$419 million aggregate principal amount of our 8.75% 2018 Senior Notes and \$275 million aggregate principal amount of our 8.5% 2016 Senior Notes.
- We received net proceeds of approximately \$1.1 billion from public offerings of common units.
- We entered into a new Utica Shale midstream joint venture to develop natural gas processing and NGL fractionation, transportation and marketing infrastructure in eastern Ohio beginning in 2012.

Impact of Business Combination on Comparability of Financial Results

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

One business combination occurred in 2011 and is included in the results of operations from the acquisition date. The Langley Processing Facilities and Ranger Pipeline acquisition closed on February 1, 2011 for consideration of \$230.7 million. As a result, eleven months of activity for the Langley Processing Facilities and Ranger Pipeline is reflected in the accompanying Consolidated Statements of Operations for the year ended December 31, 2011. The revenue and income before provision for income tax were approximately \$21.8 million and \$6.8 million, respectively, for the year ended December 31, 2011.

Results of Operations

Segment Reporting

We classify our business in the following 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 segment results are also adjusted to exclude the portion of operating income attributable to the non-controlling interests.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

The tables below present financial information, as evaluated by management, for the reported segments for the years ended December 31, 2011 and 2010. 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,		\$ Change	% Change
	2011	2010		
	(in thousands)			
Segment revenue	\$935,513	\$665,768	\$269,745	41%
Purchased product costs	506,911	308,960	197,951	64%
Net operating margin	428,602	356,808	71,794	20%
Facility expenses	82,761	81,772	989	1%
Portion of operating income attributable to non-controlling interests	5,431	6,440	(1,009)	(16)%
Operating income before items not allocated to segments	<u>\$340,410</u>	<u>\$268,596</u>	<u>\$ 71,814</u>	27%

Segment Revenue. Segment revenue increased primarily due to higher commodity prices for all areas of the segment, higher condensate revenue and an overall increase in the volume of natural gas processed and NGLs produced in Oklahoma, due in part to the expansion of the processing facilities.

Purchased Product Costs. Purchased product costs increased primarily due to higher commodity prices and an increase in the volume of natural gas processed and NGLs produced in Oklahoma.

Northeast

	Year ended December 31,		\$ Change	% Change
	2011	2010		
	(in thousands)			
Segment revenue	\$268,884	\$384,724	\$(115,840)	(30)%
Purchased product costs	91,612	252,827	(161,215)	(64)%
Net operating margin	177,272	131,897	45,375	34%
Facility expenses	27,126	19,513	7,613	39%
Operating income before items not allocated to segments	<u>\$150,146</u>	<u>\$112,384</u>	<u>\$ 37,762</u>	34%

Segment Revenue. Segment revenue decreased primarily due to a contract change related to the Langley Acquisition. Subsequent to the Langley Acquisition, we continue to market the NGLs related to natural gas processed at the Langley Processing Facilities; however we are acting as an agent and therefore record revenue net of purchase product costs. Prior to the contract change, we were acting as the principal. Segment revenue also decreased due to a decrease in volumes processed under keep-whole terms primarily due to the required repairs of a significant third-party transmission pipeline feeding our Kenova plant. The repairs of the transmission pipeline were completed in the fourth quarter of 2011, after which volumes returned to normal levels.

Purchased Product Costs. Purchased product costs decreased due to the contract change related to the Langley Acquisition discussed in the *Segment Revenue* section above. In addition, purchased product costs decreased as a percentage of revenue due to an increase in the spread between NGL and natural gas prices.

Facility Expenses. Facility expenses increased primarily due to the Langley Acquisition on February 1, 2011.

Liberty

	Year ended December 31,		\$ Change	% Change
	2011	2010		
	(in thousands)			
Segment revenue	\$248,949	\$105,911	\$143,038	135%
Purchased product costs	83,847	16,840	67,007	398%
Net operating margin	165,102	89,071	76,031	85%
Facility expenses	34,913	24,028	10,885	45%
Portion of operating income attributable to non-controlling interests	63,731	26,126	37,605	144%
Operating income before items not allocated to segments	<u>\$ 66,458</u>	<u>\$ 38,917</u>	<u>\$ 27,541</u>	71%

Segment Revenue. Segment revenue increased due to ongoing expansion of the Liberty operations and higher NGL prices. Segment revenue increased approximately \$43.7 million related to gathering and processing fees and approximately \$89.0 million related to NGL product sales.

Purchased Product Costs. Purchased product costs increased primarily due to the purchase and sale of propane from certain producers at market prices less a discount, which began in the second half of 2010.

Facility Expenses. Facility expenses increased due to costs related to the expansion of Liberty operations. The increase in costs related to expansion were partially offset by a reduction in compressor rental expense as compressors were purchased in the first quarter of 2010 and by environmental and remediation costs incurred in 2010 that did not recur in 2011.

Portion of Operating Income Attributable to Non-controlling Interests. Portion of operating income attributable to non-controlling interests represents M&R's interest in net operating income of MarkWest Liberty Midstream. The increase is the result of ongoing expansion of the Liberty operations, as well as M&R's interest increasing from 40% to 49% effective January 1, 2011. Due to our acquisition of M&R's interest effective December 31, 2011, going forward there will be no operating income allocated to non-controlling interest.

Gulf Coast

	Year ended December 31,		\$ Change	% Change
	2011	2010		
	(in thousands)			
Segment revenue	\$96,473	\$85,160	\$11,313	13%
Purchased product costs	—	—	—	N/A
Net operating margin	96,473	85,160	11,313	13%
Facility expenses	38,436	33,337	5,099	15%
Operating income before items not allocated to segments	<u>\$58,037</u>	<u>\$51,823</u>	<u>\$ 6,214</u>	12%

Segment Revenue. Segment revenue increased primarily due to increases in commodity prices and the revenues earned from the SMR which did not begin until March 2010. The increases were partially offset by a decrease in volumes due to increased maintenance activities of our refinery customers.

Facility Expenses. Facility expenses increased primarily due to operating expenses of the SMR which began in March 2010.

**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, 2011 and 2010. 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,		\$ Change	% Change
	2011	2010		
	(in thousands)			
Total segment revenue	\$1,549,819	\$1,241,563	\$308,256	25%
Derivative loss not allocated to segments	(29,035)	(53,932)	24,897	(46)%
Revenue deferral adjustment	(15,385)	—	(15,385)	N/A
Total revenue	<u>\$1,505,399</u>	<u>\$1,187,631</u>	<u>\$317,768</u>	27%
Operating income before items not allocated to segments	\$ 615,051	\$ 471,720	\$143,331	30%
Portion of operating income attributable to non-controlling interests	69,162	32,566	36,596	112%
Derivative loss not allocated to segments	(75,515)	(80,350)	4,835	(6)%
Revenue deferral adjustment	(15,385)	—	(15,385)	N/A
Compensation expense included in facility expenses not allocated to segments	(1,781)	(1,890)	109	(6)%
Facility expenses adjustments	11,419	9,091	2,328	26%
Selling, general and administrative expenses	(81,229)	(75,258)	(5,971)	8%
Depreciation	(149,954)	(123,198)	(26,756)	22%
Amortization of intangible assets	(43,617)	(40,833)	(2,784)	7%
Loss on disposal of property, plant and equipment	(8,797)	(3,149)	(5,648)	179%
Accretion of asset retirement obligations	(1,190)	(237)	(953)	402%
Income from operations	318,164	188,462	129,702	69%
(Loss) earnings from unconsolidated affiliates	(1,095)	1,562	(2,657)	(170)%
Interest income	422	1,670	(1,248)	(75)%
Interest expense	(113,631)	(103,873)	(9,758)	9%
Amortization of deferred financing costs and discount (a component of interest expense)	(5,114)	(10,264)	5,150	(50)%
Derivative gain related to interest expense	—	1,871	(1,871)	(100)%
Loss on redemption of debt	(78,996)	(46,326)	(32,670)	71%
Miscellaneous income, net	144	1,189	(1,045)	(88)%
Income before provision for income tax	<u>\$ 119,894</u>	<u>\$ 34,291</u>	<u>\$ 85,603</u>	250%

Derivative Loss Not Allocated to Segments. Unrealized gain from the change in fair value of our derivative instruments was \$0.3 million in 2011 compared to an unrealized loss of \$24.9 million in 2010. Realized loss from the settlement of our derivative instruments was \$75.8 million in 2011 compared to \$55.5 million in 2010. The total change of \$4.8 million is due mainly to volatility in commodity prices when comparing prices in 2011 with prices in 2010.

Revenue Deferral Adjustment. Revenue deferral adjustment relates primarily to certain contracts in which the cash consideration we receive for providing service is greater during the initial years of the contract compared to the later years. In accordance with GAAP, the revenue is recognized evenly over the term of the contract as we expect to perform a similar level of service for the entire term;

therefore, the revenue recognized in the current reporting period is less than the cash received. However, the chief operating decision maker and management evaluate the segment performance based on the cash consideration received and therefore the impact of the revenue deferrals is excluded for segment reporting purposes. For the year ended December 31, 2011, approximately \$7.2 million and \$8.2 million of the revenue deferral adjustment is attributable to the Southwest segment and Northeast segment, respectively. There were no revenue deferral adjustments in 2010 or 2009. Beginning in 2015, the cash consideration received from these contracts will decline and the reported segment revenue will be less than the revenue recognized for GAAP purposes.

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. The increase is due to a full year of interest expense related to the SMR in 2011 compared to approximately nine months of SMR interest expense in 2010.

Selling, General and Administrative. Selling, general and administrative expenses increased primarily due to higher labor, benefits and professional services necessary to support the overall growth of our operations.

Depreciation. Depreciation increased due to additional projects completed and placed into service during 2010 and 2011, as well as the Langley Acquisition.

Loss on Disposal of Property, Plant and Equipment. Loss relates to disposals of miscellaneous equipment, primarily in the Northeast segment.

Interest Expense. Interest expense increased primarily due to increased borrowings under our Credit Facility and a net increase in our borrowings resulting from our senior notes offerings and related redemptions in order to fund our capital plan. Interest expense also increased approximately \$1.8 million related to payments of the liability associated with the SMR Transaction that began in March 2010.

Amortization of Deferred Financing Costs and Discount. Amortization of deferred financing costs and discount decreased primarily due to the write-off of the unamortized discount associated with our 6.875% senior notes due 2014 (“2014 Senior Notes”), which were redeemed in the fourth quarter of 2010. The decrease was partially offset by the amortization of deferred financing costs related to notes issued in the fourth quarter of 2010 and 2011.

Loss on Redemption of Debt. Loss on redemption of debt relates to the redemption of approximately \$275 million of our 2016 Senior Notes and approximately \$419 million of our 2018 Senior Notes. Approximately \$7.6 million relates to the non-cash write-off of the unamortized discount and deferred finance costs associated with these senior notes and approximately \$71.4 million relates to the payment of the related call and tender premiums. See Note 16 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 reflects 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.

Provision for Income Tax. The total provision for income tax for the year ended December 31, 2011 was \$13.7 million. Refer to Note 22 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for a discussion of the significant changes in the provision.

MarkWest Hydrocarbon pays tax based on enacted and applicable corporate and state tax rates on its pro-rata share of income and deductions allocated to the Class A units by the Partnership.

The current provision for income tax was \$17.6 million for the year ended December 31, 2011. Approximately \$16.0 million is attributable to MarkWest Hydrocarbon, Inc. Of this amount, \$8.5 million is attributable to MarkWest Hydrocarbon's ownership of Class A units, and the remaining expense of \$7.5 million is related to the Corporation's NGL marketing business. The remaining \$1.6 million is related to taxes payable by the Partnership associated with the Texas Margin tax and Michigan Business Taxes. We expect the current provision for income tax to increase in 2012 due to expected increases in net income from MarkWest Hydrocarbon's NGL sales as well as additional income allocated to MarkWest Hydrocarbon as a result of its ownership of Class A units due to increases in earnings and additional income expected to be allocated by the Partnership in accordance with the Internal Revenue Code.

If the Partnership was to cause the Class A units to be disposed of (through sale or otherwise) or retired as a class of units, MarkWest Hydrocarbon would pay income taxes on the recognized gain to the full extent of the proceeds received or implied as received in excess of its tax basis. We currently do not have a plan to dispose of Class A units. During 2011, the Partnership determined it had understated its deferred tax liability related to its investment in consolidated subsidiaries for timing differences created as a result of items charged or credited directly to equity. We recorded a deferred tax liability of \$90.8 million, of which \$77.5 million related to prior years. See Note 22 to the consolidated financial statements.

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,		\$ Change	% Change
	2010	2009		
	(in thousands)			
Segment 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	<u>\$268,596</u>	<u>\$195,114</u>	<u>\$ 73,482</u>	38%

Segment Revenue. Segment revenue increased primarily due to higher NGL prices. Segment 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 segment 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 commencement of operations 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,		\$ Change	% Change
	2010	2009		
	(in thousands)			
Segment 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%

Segment Revenue. Segment 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 segment 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,		\$ Change	% Change
	2010	2009		
	(in thousands)			
Segment 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	<u>\$ 38,917</u>	<u>\$12,584</u>	<u>\$26,333</u>	209%

Segment Revenue. Segment revenue increased due to ongoing expansion of the Liberty operations and higher NGL prices. Segment 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,		\$ Change	% Change
	2010	2009		
	(in thousands)			
Segment 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	<u>\$51,823</u>	<u>\$41,675</u>	<u>\$10,148</u>	24%

Segment Revenue. Segment 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,		\$ Change	% Change
	2010	2009		
	(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	<u>\$1,187,631</u>	<u>\$ 738,283</u>	<u>\$449,348</u>	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	<u>\$ 34,291</u>	<u>\$(155,370)</u>	<u>\$189,661</u>	(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 our 2020 Senior Notes offering and related redemption of our 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 16 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.

Liquidity and Capital Resources

Our primary strategy is to expand our asset base through organic growth projects and acquisitions that are accretive to our cash available for distribution per common unit.

Our 2011 capital expenditures and our 2012 capital plan are summarized in the table below (in millions):

	2012 Full Year Plan		Actual
	Low	High	Year ended December 31, 2011
Consolidated growth capital	\$1,050	\$1,500	\$ 535
Liberty joint venture partner's share of growth capital	—	—	(130)
Utica joint venture partner's estimated share of growth capital	(150)	(200)	—
Partnership share of growth capital	900	1,300	405
Langley Acquisition	—	—	231
Partnership share of growth capital and acquisition . .	900	1,300	636
Consolidated maintenance capital	\$ 20	\$ 20	\$ 16

In addition to the capital expenditures in the above table, we spent approximately \$998 million of cash, including transaction costs, and issued approximately 19,954,000 Class B units with a value of approximately \$753 million for the purchase of the 49% interest in MarkWest Liberty Midstream from EMG.

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 may also consider the use of alternative financing strategies such as entering into additional joint venture arrangements.

Management believes that expenditures for our currently planned capital projects will be funded with cash flows from operations, current cash balances, contributions by our joint venture partners, our current borrowing capacity under the Credit Facility, additional long-term borrowings and proceeds from equity offerings. 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 17, 2012, our credit ratings were Ba2 with a Stable outlook by Moody's Investors Service, BB with a Stable outlook by Standard & Poor's, which both reflect upgrades during 2011, and BB with a Stable outlook by Fitch Ratings. 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.

Credit Facility

On December 29, 2011, we amended our Credit Facility to increase the borrowing capacity to \$900 million and to reset the uncommitted accordion feature to \$250 million, providing us with the additional financial flexibility to continue to execute our growth strategy. Earlier in 2011, we had amended the Credit Facility to reduce the interest rates and extend the maturity date to September 2016. See Note 16 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further details of our Credit Facility.

As of February 17, 2012, we had no borrowings outstanding and \$22.3 million of letters of credit outstanding under the Credit Facility, leaving approximately \$877.7 million available for borrowing.

Senior Notes Offerings and Tender Offers

During 2011, we completed a public offering for \$500 million in aggregate principal amount of 6.5% senior notes due in August 2021 (“2021 Senior Notes”) and a public offering for \$700 million in aggregate principal amount of 6.25% senior notes due in June 2022 (“2022 Senior Notes”). A portion of the \$1.2 billion combined net proceeds from these offerings was used to repurchase \$275 million aggregate principal amount of 8.5% senior notes due in July 2016 and approximately \$419 million aggregate principal amount of 8.75% senior notes due in April 2018, with the remainder used to provide additional capital for general partnership purposes.

As of December 31, 2011, we had four series of senior notes outstanding: \$81 million in aggregate principal issued in April and May 2008 and due April 2018; \$500 million in aggregate principal issued in November 2010 and due November 2020; \$500 million in aggregate principal issued in February and March 2011 and due August 2021; and \$700 million aggregate principal issued in October 2011 and due June 2022 (altogether “Senior Notes”). For further discussion of the Senior Notes and the accounting impacts, see Note 16 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K. The Credit Facility and indentures governing the Senior Notes limit the activity of the Partnership and its restricted subsidiaries. The Credit Facility and 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.

The Credit Facility limits our ability to enter into transactions with parties that require margin calls under certain derivative instruments. Under the Credit Facility, neither we nor the bank can require margin calls for outstanding derivative positions. As of February 17, 2012, 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.

Equity Offerings

On December 19, 2011, we completed a public offering of 10.0 million newly issued common units representing limited partner interests. On January 13, 2012, we issued an additional 0.7 million units pursuant to the underwriters’ exercise of their option to purchase additional common units. The total net proceeds, including the exercise of the underwriters’ option, were approximately \$559 million and were used to partially fund the cash consideration for the acquisition of the 49% non-controlling interest in MarkWest Liberty Midstream. We completed three additional public offerings earlier in 2011. In total, we issued 23.2 million common units and received net proceeds of approximately \$1.1 billion. Refer to Note 17 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for further discussion of the accounting treatment of the common unit offerings.

Utica Shale Joint Venture

Effective January 1, 2012, we and EMG Utica, LLC executed agreements to form the Utica Joint Venture, operated through MarkWest Utica EMG, to develop significant natural gas processing and NGL fractionation, transportation and marketing infrastructure in Eastern Ohio beginning in 2012.

Under the terms of the agreements, we will make an initial contribution to MarkWest Utica EMG in a nominal amount in exchange for a 60% membership interest in MarkWest Utica EMG, and EMG Utica will make an initial contribution in a nominal amount and will agree to contribute to MarkWest Utica EMG \$350 million in cash on an as needed basis (the "Initial EMG Contribution") in exchange for a 40% membership interest in MarkWest Utica EMG. Following the funding of the Initial EMG Contribution, either (i) EMG Utica will fund, as needed, all capital required to develop projects within the Utica Joint Venture until such time as EMG Utica's total investment balance reaches \$500 million (the "Minimum EMG Investment") or (ii) following the Initial EMG Contribution but prior to the first capital call requiring funds in excess of the Initial EMG Contribution, we will have the one time right to elect to fund 60% of all capital required to develop projects within the Utica Joint Venture until such time as EMG Utica's total investment balance equals the Minimum EMG Investment and EMG Utica will be required to fund the remaining 40% of all such capital. Once EMG Utica has funded capital equal to the Minimum EMG Investment, we will be required to fund, as needed, 100% of all capital required to develop projects within the Utica Joint Venture until such time as the total investment balances of us and EMG Utica are in the ratio of 60% and 40%, respectively (such time being referred to as the "First Equalization Date").

Following the First Equalization Date, we shall have the right to elect to continue to fund up to 100% of any additional capital required until such time as the investment balances of us and EMG Utica are in the ratio of 70% and 30%, respectively (such time being referred to as the "Second Equalization Date"). To the extent we do not fully exercise such right at any time prior to the Second Equalization Date, EMG Utica shall have the right, but not the obligation, to contribute such additional capital that is requested and that is not contributed by us. After the Second Equalization Date, EMG Utica shall have the right, but not the obligation, to maintain a 30% interest in MarkWest Utica EMG by funding 30% of any additional required capital.

Liquidity Risks and Uncertainties

Our ability to pay distributions to our unitholders, to fund planned capital expenditures and to make acquisitions depends upon our future operating performance. That, in turn, may be affected by prevailing economic conditions in our industry, as well as financial, business and other factors, some of which are beyond our control. Although NGL prices increased throughout 2010 and 2011, our operating performance could be negatively impacted if the increases in NGL prices are not sustained. Natural gas prices remained at low levels during 2010 and decreased further during the second half of 2011. Although low natural gas prices, combined with high and increasing NGL prices increase our earnings under keep-whole contracts in the short term, our long-term earnings could be adversely impacted, particularly from areas dependant on dry gas volumes, if the low natural gas prices do not increase resulting in decreased drilling and production from producers. Additionally, legislation currently being written and 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.

Cash Flow

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

	Year ended December 31,		Change
	2011	2010	
Net cash provided by operating activities	\$ 414,698	\$ 312,328	\$ 102,370
Net cash used in investing activities	(776,553)	(485,936)	(290,617)
Net cash provided by financing activities	411,421	143,306	268,115

Net cash provided by operating activities increased primarily due to a \$143.3 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 a \$20.3 million decrease in net cash flow from the settlement of commodity derivative positions.

Net cash used in investing activities increased primarily due to the \$230.7 million Langley Acquisition.

Net cash provided by financing activities increased primarily due to:

- \$953.2 million increase in proceeds from public equity offerings, and
- \$505.4 million increase in net borrowings.

These increases were partially offset by:

- \$997.6 million used to acquire EMG's interest in MarkWest Liberty Midstream,
- \$31.9 million decrease in cash contributions received from our joint venture partners,
- \$60.7 million increase in distributions to non-controlling interest holders due to the increased cash flow from MarkWest Liberty Midstream,
- \$61.6 million increase in premiums paid for the redemption of our 2016 Senior Notes and 2018 Senior Notes, and
- \$37.3 million increase in distributions to common unitholders due to additional units outstanding and growth in the per unit distribution.

Total Contractual Cash Obligations

A summary of our total contractual cash obligations as of December 31, 2011, is as follows (in thousands):

Type of obligation	Payment Due by Period				
	Total Obligation	Due in 2012	Due in 2013 - 2014	Due in 2015 - 2016	Thereafter
Long-term debt	\$1,847,112	\$ —	\$ —	\$ 66,000	\$1,781,112
Interest payments on long-term debt(1)	1,131,969	119,737	239,475	238,815	533,942
Operating leases and long-term storage agreement(2)	59,383	10,299	16,481	14,940	17,663
Purchase obligations(3)	192,382	180,971	11,411	—	—
Natural gas purchase obligations(4)	351,987	26,470	53,735	65,526	206,256
SMR Liability(5)	317,089	17,412	34,824	34,824	230,029
Other long-term liabilities reflected on the Consolidated Balance Sheets:					
Asset retirement obligation(6)	6,818	—	—	—	6,818
Total contractual cash obligations	\$3,906,740	\$354,889	\$355,926	\$420,105	\$2,775,820

(1) Assumes that our outstanding borrowing at December 31, 2011 remain outstanding until their respective maturity dates and we incur interest at 4.0% on the Credit Facility, 8.75% on the 2018 Senior Notes, 6.75% on the 2020 Senior Notes, 6.5% on the 2021 Senior Notes and 6.25% on the 2022 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 Northeast segment. 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 18 of the accompanying Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K).
- (6) Excludes estimated accretion expense of \$18.5 million. The total amount to be paid is approximately \$25.3 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, 2011, 2010 or 2009. 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 expect to 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.

<u>Description</u>	<u>Judgments and Uncertainties</u>	<u>Effect if Actual Results Differ from Estimates and Assumptions</u>
<p><i>Intangible Assets</i></p> <p>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.</p>	<p>The fair value of customer contracts is generally calculated using the income approach discounted future cash flows. The key assumptions include contract renewals, historical volumes, current and future capacity of the gathering system, pricing volatility and the discount rate.</p> <p>Amortization of intangibles with definite lives is calculated using the straight-line method over the estimated useful life of the intangible asset. We consider alternative methods of amortization when the intangibles assets are initially recorded, however have previously determined that alternative amortization methods do not create material differences in amortization expense each year and therefore concluded straight-lining methodology to be appropriate. 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.</p>	<p>If the actual results differ significantly from the assumptions used to determine the fair value and economic lives of intangible assets, the carrying value of the intangible asset may be over/understated resulting in an over/understatement of amortization expense as the over/understatement of the intangible assets would create an under/overstatement of other assets (i.e. goodwill).</p>

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
<p data-bbox="199 251 541 278"><i>Impairment of Long-Lived Assets</i></p> <p data-bbox="199 300 588 993">Management evaluates our long-lived assets, including intangibles, for impairment when certain events have taken place that indicate that the carrying value may not be recoverable from the expected undiscounted future cash flows. Qualitative and quantitative information is reviewed in order to determine if a triggering event has occurred or an impairment indicator exists. If we determine that a triggering event has occurred we would complete a full impairment analysis. If we determine that the carrying value of an asset group is not recoverable, a loss is recorded for the difference between the fair value and the carrying value. We evaluate our 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.</p>	<p data-bbox="617 300 1009 732">Management considers the volume of reserves dedicated to be processed by 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.</p>	<p data-bbox="1035 300 1427 378">As of December 31, 2011, there were no indicators of impairment for any of our asset groups.</p> <p data-bbox="1035 400 1427 693">A significant variance in any of the assumptions or factors used to estimate future cash flows could result in the impairment of an asset. A 10% decrease in the estimated future cash flows used in our impairment analysis would indicate a potential impairment for asset groups with a total carrying value of approximately \$60 million.</p>

<u>Description</u>	<u>Judgments and Uncertainties</u>	<u>Effect if Actual Results Differ from Estimates and Assumptions</u>
<p><i>Impairment of Goodwill</i></p> <p>Goodwill is the cost of an acquisition less the fair value of the net identifiable 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. The first step of the evaluation is a qualitative analysis to determine if it is “more likely than not” that the carrying value of a reporting unit with goodwill exceeds its fair value. The additional quantitative steps in the goodwill impairment test are only performed if we determine that it is more likely than not that the carrying value is greater than the fair value.</p>	<p>If a quantitative analysis is deemed to be required, 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.</p> <p>For the current year qualitative analysis, we analyzed the changes in the assumptions above in light of current economic conditions to determine if it was more likely than not that impairment exists. We looked at factors that include changes in the forecasted operating income and volumes for the two reporting units with goodwill, changes in the commodity price environment, changes in our per unit market value and changes in the our peers market value, and changes in industry EBITDA multiples.</p> <p>Management is 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 acquisitions involved estimating the fair value of the reporting units and allocating the purchase price for each acquisition to each reporting unit. Goodwill is then calculated for each reporting unit as the excess of the allocated purchase price over the estimated fair value of the net assets.</p>	<p>As a result of the goodwill impairment testing completed in 2011, we recorded no impairment expense. There were no indicators that it was more likely than not that the carrying value of a reporting unit exceed its fair value, based on the qualitative analysis performed.</p>

<u>Description</u>	<u>Judgments and Uncertainties</u>	<u>Effect if Actual Results Differ from Estimates and Assumptions</u>
<p><i>Impairment of Equity Investments</i></p> <p>We evaluate our equity method investment in Centrahoma 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.</p>	<p>Our impairment assessment requires us to apply judgment in estimating future cash flows from Centrahoma. The primary estimates include the expected volumes to be processed by Centrahoma, the terms of the related processing agreements, and future commodity prices. We determined that there were no material events or changes in circumstances that would indicate an other-than-temporary loss in value has occurred.</p> <p>Our impairment assessment requires us to apply judgment in estimating future cash flows. The primary estimates include the expected volumes to be processed by Centrahoma, the terms of the related processing agreements, and future commodity prices.</p>	<p>Based on the current forecasts, our ownership in Centrahoma will generate cash flows with a present value in excess of the current carrying value of the investment. 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.</p>
<p><i>Accounting for Risk Management Activities and Derivative Financial Instruments</i></p> <p>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 and/or miscellaneous income.</p>	<p>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 such as option volatilities and NGL prices that are interpolated and extrapolated due to inactive markets. These instruments are classified as Level 3 under the fair value hierarchy. All fair value measurements are appropriately adjusted for nonperformance risk.</p>	<p>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, 2011 would have affected net income before provision for income tax by approximately \$18.1 million for the year ended December 31, 2011.</p>

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
<p data-bbox="228 226 617 289"><i>Accounting for Significant Embedded Derivative Instruments</i></p> <p data-bbox="228 304 617 630">We have a Gas Purchase Agreement with Equitable (“EQT”), in which we are required to purchase natural gas based on a complex formula designed to share some of the frac-spread with EQT, through December 31, 2022. This contract has been identified as an embedded derivative and requires a complex valuation based on significant judgment.</p> <p data-bbox="228 640 617 1092">The agreement has a primary term that expires on December 31, 2022 and contains two successive term-extending options under which EQT can extend the purchase agreement an additional five years. Such options are part of the embedded feature and thus are required to be considered in the valuation of the embedded derivative. We are required to make a significant judgment about the probability that the options would be exercised when determining the value of the extension options.</p>	<p data-bbox="617 304 1036 892">We carry the EQT embedded derivative at fair value with changes in fair value recognized in income each period. The valuation requires significant judgment when forming the assumptions used. Third-party forward curves for certain commodity prices utilized in the valuation do not extend through the term of the arrangement. Thus, pricing is required to be extrapolated for those periods. We utilize multiple cash flow techniques to extrapolate NGL pricing. Due to the illiquidity of future markets, we do not believe one method is more indicative of fair value than the other methods. The fair value is also appropriately adjusted for nonperformance risk each period.</p> <p data-bbox="617 903 1036 1352">We evaluated various factors in order to determine the probability that the term-extending options would be exercised by EQT such as estimates of future gas reserves in the region, the competitive environment in which the contract operates, the commodity price environment, and EQT’s business strategy. We have asserted that the probability that EQT will exercise their option to extend the agreement is 0% as of December 31, 2011 based on the high degree of uncertainty.</p>	<p data-bbox="1036 304 1451 577">The EQT Embedded Derivative is an instrument that is not exchange-traded. The valuation of the instrument is complex and requires significant judgment. The inputs used in the valuation model require specialized knowledge, as NGL price curves do not exist for the entire term of the arrangement.</p> <p data-bbox="1036 588 1451 934">The valuation is sensitive to NGL and natural gas future price curves. Holding the natural gas curves constant, a 10% increase (decrease) in NGL price curves causes a 30% increase (decrease) in the liability as of December 31, 2011. Holding the NGL curves constant, a 10% increase (decrease) in the natural gas curves causes a 10% decrease (increase) in the liability as of December 31, 2011.</p> <p data-bbox="1036 945 1451 1197">The determination of the fair value of the option to extend is based on our judgment about the probability of EQT exercising the extension. If it were determined that the probability of exercise was not 0% as of December 31, 2011, the liability would be understated.</p>

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
<p><i>Variable Interest Entities</i></p> <p>We evaluate all legal entities in which we hold an ownership or other pecuniary interest to determine if the entity is a VIE.</p> <p>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.</p> <p>When we conclude that we hold an 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.</p> <p>We consolidate any VIE when we determine that we are the primary beneficiary. We must disclose the nature of any interests in a VIE that is not consolidated.</p>	<p>Significant judgment is exercised in determining that a legal entity is a VIE and in evaluating our interest in a VIE.</p> <p>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.</p> <p>We evaluate our 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.</p> <p>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.</p>	<p>MarkWest Pioneer is a VIE and we are considered the primary beneficiary. We have a controlling interest in the Wirth Gathering Partnership and the Bright Star Partnership, which are less-than wholly-owned but are consolidated under the voting interest model. 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 requires significant judgment and understanding of the organization. This could result in the deconsolidation of the affected subsidiary. The deconsolidation of a subsidiary would have a significant impact on our financial statements.</p> <p>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.</p>

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
<p><i>Acquisitions—Purchase Price Allocation</i></p> <p>We allocate the purchase price of an acquired business to its identifiable assets and liabilities based on estimated fair values. The excess of the purchase price over the amount allocated to the assets and liabilities is recorded as goodwill.</p> <p>For significant acquisitions, we engage outside appraisal firms to assist in the fair value determination of identifiable intangible assets such as customer relationships, trade names and any other significant assets or liabilities. We adjust the preliminary purchase price allocation, as necessary, after the acquisition closing date through the end of the measurement period of up to one year as we finalize valuations for the assets acquired and liabilities assumed.</p>	<p>Purchase price allocation methodology requires management to make assumptions and apply judgment to estimate the fair value of acquired assets and liabilities. Management estimates the fair value of assets and liabilities primarily using a market approach, income approach, or cost approach, as appropriate. Key inputs into the fair value determinations include estimates and assumptions related to future volumes, commodity prices, operating costs, replacement costs and construction costs, as well as an estimate of the expected term and profits of the related customer contract or contracts.</p>	<p>If estimates or assumptions used to complete the purchase price allocation and estimate the fair value of acquired assets and liabilities significantly differed from assumptions made, the allocation of purchase price between goodwill, intangibles and property plant and equipment could significantly differ. Such a difference would impact future earnings through depreciation and amortization expense. In addition, if forecasts supporting the valuation of the intangibles or goodwill are not achieved, impairments could arise.</p>

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 natural gas and NGL transportation, NGL 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 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 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 manage 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 2014. 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 other than MarkWest Liberty Midstream. All of our financial derivative positions are currently with participating bank group members. Management conducts a standard credit review on counterparties. 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, 2011, including the weighted-average prices (“WAVG”):

<u>WTI Crude Collars</u>	<u>Volumes (Bbl/d)</u>	<u>WAVG Floor (Per Bbl)</u>	<u>WAVG Cap (Per Bbl)</u>	<u>Fair Value (in thousands)</u>
2012	2,634	\$75.65	\$ 97.22	\$(7,557)
2013	3,714	88.08	107.45	2,114
2014	734	95.36	114.81	2,359
<u>WTI Crude Swaps</u>	<u>Volumes (Bbl/d)</u>	<u>WAVG Price (Per Bbl)</u>	<u>Fair Value (in thousands)</u>	
2012	6,555	\$87.21	\$(33,561)	
2013	4,665	92.70	(5,080)	
2014	746	99.89	1,751	
<u>Natural Gas Swaps</u>	<u>Volumes (MMBtu/d)</u>	<u>WAVG Price (Per MMBtu)</u>	<u>Fair Value (in thousands)</u>	
2012	14,377	\$4.41	\$(6,941)	
2013	980	5.13	(469)	
<u>Propane Swaps</u>	<u>Volumes (Gal/d)</u>	<u>WAVG Price (Per Gal)</u>	<u>Fair Value (in thousands)</u>	
2012 (Jan - Mar)	140,047	\$1.42	\$1,571	
<u>IsoButane Swaps</u>	<u>Volumes (Gal/d)</u>	<u>WAVG Price (Per Gal)</u>	<u>Fair Value (in thousands)</u>	
2012 (Jan - Mar)	25,051	\$1.85	\$(547)	
<u>Normal Butane Swaps</u>	<u>Volumes (Gal/d)</u>	<u>WAVG Price (Per Gal)</u>	<u>Fair Value (in thousands)</u>	
2012 (Jan - Mar)	40,083	\$1.79	\$(272)	
<u>Natural Gasoline Swaps</u>	<u>Volumes (Gal/d)</u>	<u>WAVG Price (Per Gal)</u>	<u>Fair Value (in thousands)</u>	
2012 (Jan - Mar)	92,847	\$2.29	\$632	

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, 2011, including the WAVG:

<u>WTI Crude Collars</u>	<u>Volumes (Bbl/d)</u>	<u>WAVG Floor (Per Bbl)</u>	<u>WAVG Cap (Per Bbl)</u>	<u>Fair Value (in thousands)</u>
2012	1,122	\$78.49	\$101.71	\$(2,261)
<u>WTI Crude Swaps</u>	<u>Volumes (Bbl/d)</u>	<u>WAVG Price (Per Bbl)</u>	<u>Fair Value (in thousands)</u>	
2012(1)	1,083	\$87.11		\$(7,946)
2013	1,304	94.32		(638)
<u>Natural Gas Swaps</u>	<u>Volumes (MMBtu/d)</u>	<u>WAVG Price (Per MMBtu)</u>	<u>Fair Value (in thousands)</u>	
2012	14,419	\$6.02		\$(14,435)
2013	9,793	5.34		(4,956)
2014	4,249	5.69		(2,023)
<u>Propane Swaps</u>	<u>Volumes (Gal/d)</u>	<u>WAVG Price (Per Gal)</u>	<u>Fair Value (in thousands)</u>	
2012 (Jan - Mar)	152,569	\$1.46		\$1,113
2013 (Jan - Mar, Oct - Dec)	36,885	1.29		(190)
2014 (Jan - Mar, Oct - Dec)	87,837	1.25		(522)
<u>IsoButane Swaps</u>	<u>Volumes (Gal/d)</u>	<u>WAVG Price (Per Gal)</u>	<u>Fair Value (in thousands)</u>	
2012 (Jan - Mar)	8,282	\$1.82		\$(254)
2013	3,081	1.70		(102)
2014	3,885	1.67		(91)
<u>Normal Butane Swaps</u>	<u>Volumes (Gal/d)</u>	<u>WAVG Price (Per Gal)</u>	<u>Fair Value (in thousands)</u>	
2012 (Jan - Mar)	22,944	\$1.75		\$(342)
2013	8,512	1.61		(225)
2014	10,711	1.61		(115)
<u>Natural Gasoline Swaps</u>	<u>Volumes (Gal/d)</u>	<u>WAVG Price (Per Gal)</u>	<u>Fair Value (in thousands)</u>	
2012 (Jan - Mar)	14,969	\$2.28		\$ 33
2013	5,600	2.26		327
2014	7,106	2.32		683

- (1) During the second quarter of 2011, we effectively converted our swap hedges related to our first quarter 2012 NGL exposure from crude proxy hedges to direct NGL product hedges by purchasing crude swaps to offset the existing crude swap positions. The volume of offsetting crude swaps outstanding as of December 31, 2011 was 277,095 barrels for Q1 2012. The outstanding positions were being used to manage price risk on NGL products. To continue to manage price risk on NGL products, we sold NGL product swaps through the first quarter of 2012.

The following table provides information on the volume of MarkWest Liberty Midstream's commodity derivative activity positions related to long liquids price risk at December 31, 2011, including the WAVG:

<u>Propane Swaps</u>	<u>Volumes (Gal/d)</u>	<u>WAVG Price (Per Gal)</u>	<u>Fair Value (in thousands)</u>
2012 (Jan - Mar)	49,010	\$1.54	\$684

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, 2011, including the WAVG:

<u>WTI Crude Collars</u>	<u>Volumes (Bbl/d)</u>	<u>WAVG Floor (Per Bbl)</u>	<u>WAVG Cap (Per Bbl)</u>
2012	638	\$90.00	\$108.82
<u>WTI Crude Swaps</u>		<u>Volumes (Bbl/d)</u>	<u>WAVG Price (Per Bbl)</u>
2013		796	\$98.46
2014		1,027	\$95.03
<u>Natural Gas Swaps</u>		<u>Volumes (MMBtu/d)</u>	<u>WAVG Price (Per MMBtu)</u>
2012		2,767	\$2.72
2013 (Jan - Sep)		634	\$3.70

The following tables provide information on the derivative positions of MarkWest Liberty Midstream related to long liquids price risk that we have entered into subsequent to December 31, 2011, including the WAVG:

<u>WTI Crude Collars</u>	<u>Volumes (Bbl/d)</u>	<u>WAVG Floor (Per Bbl)</u>	<u>WAVG Cap (Per Bbl)</u>
2012 (Apr - Dec)	682	\$90.00	\$108.99
2013	494	92.00	108.67

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 commodity contract is a component of a broader regional arrangement that also includes a keep-whole processing agreement. This contract is accounted for as an embedded derivative and is recorded at fair value. The changes in fair value of this commodity contract are based on the difference between the contractual and index pricing and are recorded in earnings through *Derivative loss related to purchased product costs*. In February 2011, we executed agreements with the producer to extend the commodity contract and the related processing agreement from March 31, 2015 to December 31, 2022. As of December 31, 2011, the estimated fair value of this contract was a liability of \$114.9 million and the recorded value was a liability of \$61.4 million. The recorded liability does not include the inception fair value of the commodity contract related to the extended period from April 1, 2015 to December 31, 2022. In accordance with GAAP for non-option embedded derivatives, the fair value of this extended portion of the commodity contract at its inception of February 1, 2011 is deemed to be allocable to the host processing contract and,

therefore, not recorded as a derivative liability. See the following table for a reconciliation of the liability recorded for the embedded derivative as of December 31, 2011 (in thousands):

Fair value of commodity contract	\$114,928
Inception value for period from April 1, 2015 to December 31, 2022	<u>(53,507)</u>
Derivative liability as of December 31, 2011	<u>\$ 61,421</u>

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 changes in the fair value of the derivative component of this contract is recognized as *Derivative (gain) loss related to facility expenses*. As of December 31, 2011, the estimated fair value of this contract was an asset of \$7.5 million.

Interest Rate Risk

Our primary interest rate risk exposure results from our Credit Facility which has a borrowing capacity of \$900 million. As of February 17, 2012, we have no 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 million. The swaps were intended to mitigate the effects of changes in fair value due to changes in the benchmark interest rate (one-month LIBOR). We managed the fair value risk on 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.

<u>Long-Term Debt</u>	<u>Interest Rate</u>	<u>Lending Limit</u>	<u>Due Date</u>	<u>Outstanding at December 31, 2011</u>
Credit Facility	Variable	\$900 million	September 2016	\$ 66 million
2018 Senior Notes	Fixed	\$ 81 million	April 2018	\$ 81 million
2020 Senior Notes	Fixed	\$500 million	November 2020	\$500 million
2021 Senior Notes	Fixed	\$500 million	August 2021	\$500 million
2022 Senior Notes	Fixed	\$700 million	June 2022	\$700 million

Based on our overall interest rate exposure at December 31, 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. Based on our overall interest rate exposure at February 17, 2012, a hypothetical increase or decrease of one percentage point in interest rates applied to borrowings under our Credit Facility would not change earnings.

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

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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, 2011 and 2010, and the related consolidated statements of operations, changes in equity, and cash flows for each of the three years in the period ended December 31, 2011. 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, 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, 2011, 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, 2012 expressed an unqualified opinion on the Partnership's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 28, 2012

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

	December 31, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents (\$2,684 and \$2,913, respectively)	\$ 117,016	\$ 67,450
Restricted cash	26,193	—
Receivables, net (\$1,569 and \$43,783, respectively)	226,561	179,209
Inventories (\$0 and \$8,431)	41,006	23,432
Fair value of derivative instruments	8,698	4,345
Deferred income taxes	14,885	16,090
Other current assets (\$169 and \$272, respectively)	11,748	8,020
Total current assets	446,107	298,546
Property, plant and equipment (\$156,808 and \$849,986, respectively)	3,302,369	2,613,027
Less: accumulated depreciation (\$15,551 and \$38,169, respectively)	(438,062)	(294,003)
Total property, plant and equipment, net	2,864,307	2,319,024
Other long-term assets:		
Restricted cash (\$0 and \$28,001)	—	28,001
Investment in unconsolidated affiliate	27,853	28,688
Intangibles, net of accumulated amortization of \$168,168 and \$124,568, respectively	603,767	613,578
Goodwill	67,918	9,421
Deferred financing costs, net of accumulated amortization of \$13,194 and \$11,445, respectively	41,798	32,901
Deferred contract cost, net of accumulated amortization of \$2,262 and \$1,950, respectively	988	1,300
Fair value of derivative instruments	16,092	417
Other long-term assets (\$102 and \$383, respectively)	1,595	1,486
Total assets	\$4,070,425	\$3,333,362
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable (\$96 and \$5,945, respectively)	\$ 179,871	\$ 122,473
Accrued liabilities (\$1,144 and \$64,713, respectively)	171,451	153,869
Deferred income taxes	—	11
Fair value of derivative instruments	90,551	65,489
Total current liabilities	441,873	341,842
Deferred income taxes	93,664	87,881
Fair value of derivative instruments	65,403	66,290
Long-term debt, net of discounts of \$1,050 and \$1,566, respectively	1,846,062	1,273,434
Other long-term liabilities (\$73 and \$154, respectively)	121,356	105,349
Commitments and contingencies (see Note 18)		
Equity:		
Common units (94,940 and 71,440 common units issued and outstanding, respectively)	679,309	993,049
Class B units (19,954 and 0 units issued and outstanding, respectively)	752,531	—
Non-controlling interest in consolidated subsidiaries	70,227	465,517
Total equity	1,502,067	1,458,566
Total liabilities and equity	\$4,070,425	\$3,333,362

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,		
	2011	2010	2009
Revenue:			
Revenue	\$1,534,434	\$1,241,563	\$ 858,635
Derivative loss	(29,035)	(53,932)	(120,352)
Total revenue	1,505,399	1,187,631	738,283
Operating expenses:			
Purchased product costs	682,370	578,627	408,826
Derivative loss related to purchased product costs	52,960	27,713	68,883
Facility expenses	173,598	151,449	126,977
Derivative gain related to facility expenses	(6,480)	(1,295)	(373)
Selling, general and administrative expenses	81,229	75,258	63,728
Depreciation	149,954	123,198	95,537
Amortization of intangible assets	43,617	40,833	40,831
Loss on disposal of property, plant and equipment	8,797	3,149	1,677
Accretion of asset retirement obligations	1,190	237	198
Impairment of goodwill and long-lived assets	—	—	5,855
Total operating expenses	1,187,235	999,169	812,139
Income (loss) from operations	318,164	188,462	(73,856)
Other income (expense):			
(Loss) earnings from unconsolidated affiliates	(1,095)	1,562	3,505
Gain on sale of unconsolidated affiliate	—	—	6,801
Interest income	422	1,670	349
Interest expense	(113,631)	(103,873)	(87,419)
Amortization of deferred financing costs and discount (a component of interest expense)	(5,114)	(10,264)	(9,718)
Derivative gain related to interest expense	—	1,871	2,509
Loss on redemption of debt	(78,996)	(46,326)	—
Miscellaneous income, net	144	1,189	2,459
Income (loss) before provision for income tax	119,894	34,291	(155,370)
Provision for income tax expense (benefit):			
Current	17,578	7,655	8,072
Deferred	(3,929)	(4,466)	(50,088)
Total provision for income tax	13,649	3,189	(42,016)
Net income (loss)	106,245	31,102	(113,354)
Net income attributable to non-controlling interest	(45,550)	(30,635)	(5,314)
Net income (loss) attributable to the Partnership	\$ 60,695	\$ 467	\$(118,668)
Net income (loss) attributable to the Partnership's common unitholders per common unit (Note 23):			
Basic	\$ 0.75	\$ (0.01)	\$ (1.97)
Diluted	\$ 0.75	\$ (0.01)	\$ (1.97)
Weighted average number of outstanding common units:			
Basic	78,466	70,128	60,957
Diluted	78,619	70,128	60,957
Cash distribution declared per common unit	\$ 2.75	\$ 2.56	\$ 2.56

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

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

	Common Units		Class B Units		Non-controlling Interest	Total
	Units	Amount	Units	Amount		
December 31, 2008	56,640	\$ 1,144,854	—	\$ —	\$ 3,301	\$ 1,148,155
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
Deferred income tax impact from changes in equity	—	(10,236)	—	—	—	(10,236)
Net (loss) income	—	(118,668)	—	—	5,314	(113,354)
December 31, 2009	66,275	1,026,814	—	—	282,739	1,309,553
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,	—	—	—	—	158,293	158,293
Deferred income tax impact from changes in equity	—	(7,614)	—	—	—	(7,614)
Net income	—	467	—	—	30,635	31,102
December 31, 2010	71,440	993,049	—	—	465,517	1,458,566
Share-based compensation activity	275	8,083	—	—	—	8,083
Excess tax benefits related to share-based compensation	—	1,084	—	—	—	1,084
Distributions paid	—	(218,398)	—	—	(66,887)	(285,285)
Issuance of units in public offerings, net of offering costs	23,225	1,095,488	—	—	—	1,095,488
Issuance of Class B units	—	—	19,954	752,531	—	752,531
Contributions to MarkWest Liberty Midstream joint venture	—	—	—	—	126,392	126,392
Purchase of non-controlling interest of MarkWest Liberty M&R, net of tax benefit	—	(1,198,465)	—	—	(500,345)	(1,698,810)
Deferred income tax impact from changes in equity	—	(62,227)	—	—	—	(62,227)
Net income	—	60,695	—	—	45,550	106,245
December 31, 2011	<u>94,940</u>	<u>\$ 679,309</u>	<u>19,954</u>	<u>\$752,531</u>	<u>\$ 70,227</u>	<u>\$ 1,502,067</u>

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,		
	2011	2010	2009
Cash flows from operating activities:			
Net income (loss)	\$ 106,245	\$ 31,102	\$(113,354)
Adjustments to reconcile net income (loss) to net cash provided by operating activities (net of acquisitions):			
Depreciation	149,954	123,198	95,537
Amortization of intangible assets	43,617	40,833	40,831
Impairment of goodwill and long-lived assets	—	—	5,855
Loss on redemption of debt	78,996	46,326	—
Amortization of deferred financing costs and discount	5,114	10,264	9,718
Accretion of asset retirement obligations	1,190	237	198
Amortization of deferred contract cost	312	312	312
Phantom unit compensation expense	13,479	15,319	7,448
Loss (earnings) of unconsolidated affiliates	1,095	(1,562)	(3,505)
Gain on sale of unconsolidated affiliate	—	—	(6,801)
Contribution to unconsolidated affiliate	(560)	—	—
Distributions from unconsolidated affiliate	300	2,508	—
Unrealized loss on derivative instruments	4,147	28,475	227,920
Loss on disposal of property, plant and equipment	8,797	3,149	1,677
Deferred income taxes	(3,929)	(4,466)	(50,088)
Other	1,626	—	(2,228)
Changes in operating assets and liabilities, net of working capital acquired:			
Receivables	(45,463)	(37,090)	(33,133)
Inventories	(16,025)	5,710	6,245
Other current assets	(3,728)	2,654	1,074
Accounts payable and accrued liabilities	54,745	45,361	30,717
Other long-term assets	(307)	174	(2,808)
Other long-term liabilities	15,093	(176)	7,486
Net cash provided by operating activities	<u>414,698</u>	<u>312,328</u>	<u>223,101</u>
Cash flows from investing activities:			
Restricted cash	2,006	(28,001)	—
Capital expenditures	(551,281)	(458,668)	(486,623)
Acquisition of business	(230,728)	—	—
Equity investments	—	—	(405)
Proceeds from sale of unconsolidated affiliate	—	—	25,000
Proceeds from disposal of property, plant and equipment	3,450	733	275
Net cash flows used in investing activities	<u>(776,553)</u>	<u>(485,936)</u>	<u>(461,753)</u>
Cash flows from financing activities:			
Proceeds from revolving credit facility	1,182,200	494,404	725,200
Payments of revolving credit facility	(1,116,200)	(553,704)	(850,600)
Proceeds from long-term debt	1,199,000	500,000	117,000
Payments of long-term debt	(693,888)	(375,000)	—
Payments of premiums on redemption of long-term debt	(71,377)	(9,732)	—
Payments for debt issuance costs, deferred financing costs and registration costs	(20,163)	(20,912)	(8,554)
Acquisition of non-controlling interest, including transaction costs	(997,601)	—	—
Contributions to MarkWest Liberty Midstream joint venture, net	126,392	158,293	194,536
Proceeds from sale of equity interest in joint venture, net	—	—	60,654
Payments of SMR Liability	(1,875)	(1,354)	—
Proceeds from SMR Transaction	—	—	73,129
Proceeds from public equity offerings, net	1,095,488	142,255	178,565
Cash paid for taxes related to net settlement of share-based payment awards	(6,354)	(3,834)	(1,385)
Excess tax benefits related to share-based compensation	1,084	98	—
Payment of distributions to common unitholders	(218,398)	(181,058)	(155,307)
Payment of distributions to non-controlling interest	(66,887)	(6,150)	(155)
Net cash flows provided by financing activities	<u>411,421</u>	<u>143,306</u>	<u>333,083</u>
Net increase (decrease) in cash and cash equivalents	49,566	(30,302)	94,431
Cash and cash equivalents at beginning of year	67,450	97,752	3,321
Cash and cash equivalents at end of year	<u>\$ 117,016</u>	<u>\$ 67,450</u>	<u>\$ 97,752</u>

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

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

1. Organization and Basis of Presentation

MarkWest Energy Partners, L.P. (“MarkWest Energy Partners”) was formed in January 2002 as a Delaware limited partnership. In February 2008, MarkWest Energy Partners completed its Merger with MarkWest Hydrocarbon, Inc. (the “Corporation” or “MarkWest Hydrocarbon”) and MWEP, L.L.C, whereby MarkWest Hydrocarbon became a wholly-owned subsidiary of MarkWest Energy Partners. 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 and continues to expand this position through the growth of its operations in the Marcellus Shale. Finally, the Partnership owns a crude oil transportation pipeline in Michigan. The Partnership’s principal executive office is located in Denver, Colorado.

The Partnership’s consolidated financial statements include all majority-owned or majority-controlled subsidiaries. In addition, MarkWest Liberty Midstream and MarkWest Pioneer, variable interest entities for which the Partnership has been determined to be the primary beneficiary, are included in the consolidated financial statements. Effective December 31, 2011, the Partnership acquired the remaining 49% interest of MarkWest Liberty Midstream. As a result, as of December 31, 2011, MarkWest Liberty Midstream is not a variable interest entity but is consolidated as a wholly-owned subsidiary (see Note 4 for further discussion of MarkWest Pioneer and MarkWest Liberty Midstream). For non-wholly-owned subsidiaries, the interests owned by third parties have been recorded as *Non-controlling interest in consolidated subsidiaries* in the accompanying Consolidated Balance Sheets. 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.

2. Summary of Significant Accounting Policies

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.

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

2. Summary of Significant Accounting Policies (Continued)

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 certain capital projects are completed and the third party releases the restriction. Restricted cash balances for which the restrictions will not be released within a period of twelve months are 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 and supplies, 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, which are depreciated over a period of three to ten years.

The Partnership evaluates transactions involving the sale of property, plant and equipment 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. The Partnership's 2009 sale of the SMR, which was considered in-substance real estate, was not considered a sale 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 in 2009 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.

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

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.

Investment in Unconsolidated Affiliate

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.

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.

Intangibles

The Partnership’s intangibles are comprised of customer contracts and relationships acquired in business combinations and 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

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

2. Summary of Significant Accounting Policies (Continued)

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 reporting unit is less than its carrying amount. The Partnership first assesses qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. If a two-step process goodwill impairment test is required, 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 an 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 contractual term of the related obligations or, in certain circumstances, accelerated if the obligation is refinanced, using the effective interest method.

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

2. Summary of Significant Accounting Policies (Continued)

Deferred Contract Cost

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 all of its derivative instruments separate 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). Changes in the fair value of derivative instruments are reported in the Statement of Operations in accounts related to the item whose value or cash flows are being managed. 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 manage 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 manage costs, typically in a keep-whole arrangement. Facility expenses gains and losses relate to a contract utilized to manage 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). Changes in risk management activities are reported as an adjustment to net income in computing cash flow from operating activities on the accompanying Consolidated Statements of Cash Flows.

During 2011, 2010 and 2009, 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 approximates fair value due to the variable interest rate that approximates current market rates. 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, 2011 and 2010 (in thousands):

	<u>December 31, 2011</u>		<u>December 31, 2010</u>	
	<u>Carrying Value</u>	<u>Fair Value</u>	<u>Carrying Value</u>	<u>Fair Value</u>
Long-term debt	\$1,846,062	\$1,880,710	\$1,273,434	\$1,333,875
SMR Liability	93,909	119,887	95,784	125,600

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

2. Summary of Significant Accounting Policies (Continued)

The fair value of the long-term debt is estimated based on recent market quotes. The fair value of the SMR Liability is estimated using a discounted cash flow approach based on the contractual cash flows and the Partnership's unsecured borrowing rate.

Fair Value Measurement

Financial assets and liabilities recorded at fair value in the Consolidated Balance Sheet are categorized based upon a fair value hierarchy established by GAAP, which classifies the inputs used to measure fair value into the following levels:

- 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 16 as they have significant unobservable inputs.

The methods and assumptions described above may produce a fair value that may not be realized in future periods upon settlement. 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. 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 exchange and storage of NGLs; and gathering and transportation of crude oil. The revenue the Partnership earns from these arrangements is generally directly

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

2. Summary of Significant Accounting Policies (Continued)

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.

- *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 delivers an agreed-upon percentage of the residue gas and NGLs to the producer and sell the volumes the Partnership keeps to third parties.
- *Percent-of-index arrangements*—Under percent-of-index arrangements, the Partnership purchases 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 then gathers and delivers the natural gas to pipelines where the Partnership resells 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. 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 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,

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

2. Summary of Significant Accounting Policies (Continued)

the amount of revenue is determinable when the sale of the applicable product has been completed upon delivery and transfer of title.

Collectability is reasonably assured. Collectability is evaluated on a customer-by-customer basis. New and existing customers are subject to a credit review process, which evaluates a customer's financial position (e.g. cash position and credit rating) and its ability to pay. If collectability 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 customers' 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 acts as an agent and earns a fixed amount and does not take ownership of the gas and/or NGLs.

Amounts billed to customers for shipping and handling, including fuel costs, 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 adjusted 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 its share-based compensation plans as described further in Note 20. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit. 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.

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

2. Summary of Significant Accounting Policies (Continued)

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 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 balances are classified as long-term in the accompanying Consolidated Balance Sheets. All changes in the tax bases of assets and liabilities are allocated among continued operations and items charged or credited directly to equity.

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 Class A units were issued to the Corporation as part of the Merger and represent limited partner interests with the same rights as common units except that the Class A units do not have voting rights, except as required by law. Class A units are not treated as outstanding common units in the Consolidated Balance Sheet as they are eliminated in the consolidation of the Corporation. The deferred income tax component relates to the change in the temporary 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.

Earnings (Loss) Per Unit

The Partnership's outstanding phantom units are considered to be participating securities and the Class B units are considered to be a separate class of common units that do not participate in cash distributions. 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 and Class B units, by the weighted average number of common units outstanding during the period. The amount allocable to the phantom units and Class B 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, no earnings are allocable to Class B units as they do not

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

2. Summary of Significant Accounting Policies (Continued)

participate in cash distributions. 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 units and Class B units is based on actual distributions to the phantom units and Class B unitholders. Diluted earnings per unit is calculated by dividing net income attributable to the Partnership, after deducting amounts allocable to the outstanding phantom units and Class B 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 and Class B 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 acquires additional interest or if the subsidiary issues or repurchases its own shares. If the transaction does not result in a change in control over the subsidiary, the transaction is accounted for as an equity transaction. If a sale 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. If the purchase of additional interest occurs which changes the acquirer's ownership interest from non-controlling to controlling, the acquirer's preexisting interest in the acquiree is remeasured to its fair value, with a resulting gain or loss recorded in earnings upon consummation of the business combination. Once an entity has control of a subsidiary, its acquisitions of some or all of the noncontrolling interests in that subsidiary are accounted for as equity transactions and are not considered to be a business combination. See Note 4 for a description of the transactions that resulted in a change in the Partnership's ownership interest in a subsidiary and the impact of these transactions to the financial statements.

Recent Accounting Pronouncements

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 did not have a material effect on the Partnership's consolidated financial statements.

In May 2011, the FASB amended the accounting guidance for fair value measurement and disclosure. The amended guidance was intended to converge the fair value measurement and disclosure requirements under GAAP and IFRS. The amendment primarily clarifies the application of the existing guidance and provides for increased disclosures, particularly related to Level 3 fair value measurements. The amended

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

2. Summary of Significant Accounting Policies (Continued)

guidance is effective for the Partnership prospectively as of January 1, 2012. Except for the additional disclosures, the adoption of the amended guidance is not expected to have a material effect on the Partnership's consolidated financial statements.

In September 2011, the FASB amended the accounting guidance for goodwill impairment testing. The amended guidance provides an entity with an option to first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. The Partnership elected early adoption for the period ended December 31, 2011 and the adoption did not have a material effect on the Partnership's consolidated financial statements.

In December 2011, the FASB amended the accounting guidance for balance sheet offsetting for financial assets and financial liabilities. The amended guidance was intended to help investors and other financial statement users to better assess the effect or potential effect of offsetting arrangements on a company's financial position and provides for increased disclosures. The amended guidance is effective for the Partnership prospectively as of January 1, 2013. Except for the additional disclosures, the adoption of the amended guidance is not expected to have a material effect on the Partnership's consolidated financial statements.

3. Business Combination

On February 1, 2011, the Partnership acquired natural gas processing and NGL pipeline assets from EQT for a cash purchase price of approximately \$230.7 million. The assets acquired include natural gas processing facilities located near Langley, Kentucky, consisting of a cryogenic natural gas processing plant with a capacity of approximately 100 MMcf/d and a refrigeration natural gas processing plant with a capacity of approximately 75 MMcf/d, the partially constructed Ranger pipeline that extends through parts of Kentucky and West Virginia, and certain other related assets. The acquired assets do not include certain residue gas compression and transportation facilities at the same location as the Langley Processing Facilities. This acquisition is referred to as the Langley Acquisition. In connection with the Langley Acquisition, the Partnership completed the construction of the Ranger Pipeline to connect the Langley Processing Facilities to the Partnership's existing pipeline that transports NGLs to its Siloam fractionation facility in South Shore, Kentucky.

Concurrently with the closing of the Langley Acquisition, the Partnership entered into a long-term agreement to process certain natural gas owned or controlled by EQT at the Langley Processing Facilities. The processing agreement requires the Partnership to install an additional cryogenic natural gas processing plant with a capacity of at least 60 MMcf/d in 2012. The Partnership exchanges the NGLs produced at the Langley Processing Facilities for fractionated products from its Siloam facility and markets the fractionated products on behalf of EQT in accordance with a long-term NGL exchange and marketing agreement. As a result of the acquisition, the Partnership has significantly expanded its midstream operations in the liquids-rich gas areas of the Appalachian Basin.

The Langley Acquisition is accounted for as a business combination. The total purchase price is allocated to the identifiable assets acquired and liabilities assumed based on the estimated fair values at the acquisition date. The remaining purchase price in excess of the fair value of the identifiable assets and liabilities is recorded as goodwill. The acquired assets and the related results of operations are included in the Partnership's Northeast segment.

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

3. Business Combination (Continued)

The following table summarizes the purchase price allocation for the Langley Acquisition (in thousands):

Property, plant and equipment	\$136,525
Goodwill	58,497
Intangible asset	33,900
Inventory	1,806
Total	<u>\$230,728</u>

The goodwill recognized from the Langley Acquisition results primarily from the Partnership's ability to continue to grow its business in the liquids-rich gas areas of the Appalachian Basin and access additional markets in a competitive environment as a result of securing the processing rights for a large area of dedicated acreage and acquiring expanded midstream infrastructure in the acquisition. All of the goodwill is deductible for tax purposes.

The intangible asset consists of an identifiable customer contract. The acquired intangible will be amortized on a straight-line basis over the estimated remaining customer contract useful life of approximately twelve years.

The results of operations from the Langley Acquisition are included in the consolidated financial statements from the acquisition date. Revenue and income before provision for income tax related to the Langley Acquisition were approximately \$21.8 million and \$6.8 million, respectively, for the year ended December 31, 2011.

Pro forma financial results that give effect to the Langley Acquisition are not presented as it is impracticable to obtain the necessary information. EQT did not operate the acquired assets as a stand-alone business and, therefore, historical financial information that is consistent with the operations under the current agreements is not available.

4. Variable Interest Entities

MarkWest Liberty Midstream

On February 27, 2009, the Partnership entered into a joint venture with 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. Under the original joint venture agreement, MarkWest Liberty Midstream was owned 60% by the Partnership and 40% by M&R. Upon closing, the Partnership contributed its existing Marcellus Shale natural gas gathering and processing assets with an agreed to value of \$107.5 million and M&R contributed cash of \$50.0 million to MarkWest Liberty Midstream. M&R also committed to fund the next \$150 million of MarkWest Liberty Midstream's capital requirements after which time the Partnership agreed to fund the future capital requirements until each member's contributed capital was proportionate to its ownership interest ("Equalization"). Effective November 1, 2009, the Partnership and M&R executed the Second Amended and Restated Limited Liability Company Agreement of MarkWest Liberty Midstream & Resources L.L.C. pursuant to which M&R increased its participation in MarkWest Liberty Midstream.

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

4. Variable Interest Entities (Continued)

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 increased from 40% to 49%. In addition to its initial contribution of assets at closing, the Partnership contributed an additional \$252.4 million, \$171.1 million, and \$8.0 million during 2011, 2010, and 2009 respectively. In addition to its \$50 million contribution at closing, M&R contributed \$126.4 million, \$158.3 million, and \$150.0 million during 2011, 2010 and 2009, respectively.

The cumulative capital contributed by M&R exceeded its ownership interest until the third quarter of 2011. Under the terms of the joint venture agreement, M&R received a special \$1.3 million, \$11.4 million, and \$3.4 million allocation of net income from MarkWest Liberty Midstream during the years ended December 31, 2011, 2010 and 2009, respectively, due to its excess contributions. The allocation is recorded in *Net income attributable to non-controlling interest* in the Consolidated Statements of Operations.

The Partnership determined that MarkWest Liberty Midstream was a VIE until December 31, 2011, primarily due to the Partnership's disproportionate economic interests as compared to its voting interests in the entity. Additionally, MarkWest Liberty Midstream had insufficient equity at risk, as evidenced by the additional capital funding requirements discussed above. Although voting interests were shared equally between the respective members of MarkWest Liberty Midstream until December 31, 2011, the Partnership had concluded that it was 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 gave it the power to direct the activities that most significantly affected the economic performance of MarkWest Liberty Midstream. As the primary beneficiary of a VIE, the Partnership consolidated MarkWest Liberty Midstream for all periods presented in the accompanying financial statements.

Effective December 31, 2011, the Partnership acquired M&R's 49% non-controlling interest of MarkWest Liberty Midstream for total consideration of approximately \$1,746.5 million, which includes cash of \$994.0 million and approximately 19,954,000 Class B units valued at approximately \$752.5 million (see Note 17 for discussion of Class B units). The Partnership paid transaction fees of approximately \$3.6 million related to this transaction. As a result of the transaction, MarkWest Liberty Midstream is a wholly-owned subsidiary of the Partnership and is no longer a VIE. However, the Partnership continues to consolidate MarkWest Liberty Midstream.

In accordance with GAAP, a change in the Partnership's ownership interest in a subsidiary while it retains a controlling interest is recorded as an equity transaction. As such, the fair value of the consideration paid in excess of the \$500.3 million carrying amount of the non-controlling interest acquired and the related transaction costs of approximately \$3.6 million are recognized as a reduction of equity attributable to the Partnership's common units. See table below in this Note 4 for a summary of the impact on equity attributable to the Partnership's common units as of December 31, 2011.

As the accompanying *Consolidated Statements of Operations* include the historical results of MarkWest Liberty Midstream, pro forma results of operations are not presented for this acquisition of non-controlling interest. The primary impact of the transaction on the financial statements is that none of MarkWest Liberty Midstream's net income will be allocable to a non-controlling interest in future periods as 100% of MarkWest Liberty Midstream's net income will be attributable to the Partnership. During the years ended December 31, 2011, 2010 and 2009, the portion of MarkWest Liberty

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

4. Variable Interest Entities (Continued)

Midstream's net income attributable to non-controlling interest was \$44.0 million, \$27.9 million and \$6.3 million, respectively.

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. In 2009, the Partnership sold a 50% interest in MarkWest Pioneer to ArcLight Capital Partners, LLC. Under the terms of the sale, the Partnership was required to fund all of the capital expenditures required to complete construction of the Arkoma Connector Pipeline in excess of \$125 million, and as a result the Partnership has made capital contributions to MarkWest Pioneer in excess of its stated ownership and voting interests. A wholly-owned subsidiary of the Partnership serves as the operator and provides field operating and general and administrative services for fixed fees. 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. Although voting interests are shared equally between the respective members of MarkWest Pioneer, the Partnership has concluded that it is the primary beneficiary based on its 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 of December 31, 2011, MarkWest Pioneer is the only VIE included in the Partnership's consolidated financial statements. The assets and liabilities attributable to MarkWest Pioneer as of December 31, 2011 are disclosed parenthetically on the accompanying Consolidated Balance Sheets. As of December 31, 2010, MarkWest Pioneer and MarkWest Liberty Midstream were both consolidated

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

4. Variable Interest Entities (Continued)

VIEs. The following table shows the assets and liabilities attributable to VIEs reflected in the Consolidated Balance Sheets as of December 31, 2010 (in thousands):

	<u>MarkWest Liberty Midstream</u>	<u>MarkWest Pioneer</u>	<u>Total</u>
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	<u>\$743,943</u>	<u>\$151,657</u>	<u>\$895,600</u>
LIABILITIES			
Accounts payable	\$ 5,945	\$ —	\$ 5,945
Accrued liabilities	63,450	1,263	64,713
Other long-term liabilities	86	68	154
Total liabilities	<u>\$ 69,481</u>	<u>\$ 1,331</u>	<u>\$ 70,812</u>

The assets of MarkWest Pioneer are not available to the Partnership for any other purpose, including collateral for its secured debt (see Note 16 and Note 25). MarkWest Pioneer's asset balances can only be used to settle its own obligations and not those of the Partnership or any other subsidiaries of the Partnership. The liabilities of MarkWest Pioneer do not represent additional claims against the Partnership's general assets and the creditors or beneficial interest holders of MarkWest Pioneer do not have recourse to the general credit of the Partnership. The Partnership's maximum exposure to loss as a result of its involvement with the MarkWest Pioneer includes its equity investment and any operating expense incurred by the subsidiary operator in excess of its subsidiary's compensation for the performance of those services.

For the years ended December 31, 2011, 2010 and 2009, the results of operations and cash flow information of MarkWest Liberty Midstream and MarkWest Pioneer comprise substantially all of the results of operations and cash flow information of the non-guarantor subsidiaries (see Note 25). Individually, the results of operations and cash flow of MarkWest Pioneer, the remaining VIE, are not material to the Partnership. The Partnership did not provide any financial support to the MarkWest Liberty Midstream or MarkWest Pioneer that it was not contractually obligated to provide during the years ended December 31, 2011, 2010 and 2009.

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

4. Variable Interest Entities (Continued)

As discussed above, the Partnership's ownership interest in MarkWest Liberty Midstream and MarkWest Pioneer changed as a result of transactions completed in 2009 and 2011. The following table summarizes the effect of these changes of ownership interest on the equity attributable to the Partnership's common units (in thousands):

	<u>Year ended December 31,</u>		
	<u>2011</u>	<u>2010</u>	<u>2009</u>
Net income (loss) attributable to the Partnership	\$ 60,695	\$467	\$(118,668)
Transfers to the non-controlling interests:			
Decrease in common unit equity for 2011 acquisition of equity interest in MarkWest Liberty Midstream, net of \$51,321 income tax benefit	(1,194,865)	—	—
Decrease in common unit equity for transaction costs related to 2011 acquisition of equity interest in MarkWest Liberty Midstream	(3,600)	—	—
Decrease in common unit equity for transfer to non-controlling interest from 2009 sale of equity interest in MarkWest Pioneer, net of \$1,491 income tax benefit	—	—	(10,288)
Decrease in common unit equity for transaction costs related to 2009 sales of equity interests in MarkWest Liberty Midstream and MarkWest Pioneer	—	—	(7,310)
Net (loss) income attributable to the Partnership and transfers to the non-controlling interest	<u><u>\$(1,137,770)</u></u>	<u><u>\$467</u></u>	<u><u>\$(136,266)</u></u>

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

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 imputes interest on the SMR Liability at 9.35% annually, its incremental borrowing rate at transaction consummation. 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, 2011 and 2010, the following amounts related to the SMR are included in the accompanying Consolidated Balance Sheets (in thousands):

	<u>December 31, 2011</u>	<u>December 31, 2010</u>
ASSETS		
Property, plant and equipment, net of accumulated depreciation of \$9,658 and \$4,390, respectively	\$95,705	\$100,973
LIABILITIES		
Accrued liabilities	\$ 2,058	\$ 1,875
Other long-term liabilities	91,851	93,909

Sale of Starfish

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.

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

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

6. Derivative Financial Instruments (Continued)

conditioning at its 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 the Partnership can meet its cash distribution objectives, debt service requirements and fund its capital expenditures, the Partnership executes a strategy governed by the risk management policy approved by 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 contracts utilized are swaps, options and fixed price forward contracts traded on the OTC market. The risk management policy does not allow for trading 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 manages 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 derivative positions outstanding on December 31, 2011, the Partnership has mitigated a portion of its expected commodity price risk through the fourth quarter of 2014. The Partnership would be exposed to additional commodity risk in certain situations that include, but are not limited to, when 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 will 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 other than MarkWest Liberty Midstream. 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

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

6. Derivative Financial Instruments (Continued)

cause volatility in the Statement of Operations as the Partnership recognizes in current earnings all unrealized gains and losses from the changes in the fair value of its derivatives.

Embedded Derivative in Debt Contract

On May 26, 2009, the Partnership completed the private placement of senior notes with contingent written put options as described in Note 16. 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 multiple embedded derivatives requiring separate accounting, the embedded derivatives must be aggregated and accounted for as a compound embedded derivative. 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

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

6. Derivative Financial Instruments (Continued)

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

<u>Derivative contracts not designated as hedging instruments and their balance sheet location</u>	Assets		Liabilities	
	Fair Value at December 31, 2011	Fair Value at December 31, 2010	Fair Value at December 31, 2011	Fair Value at December 31, 2010
<i>Commodity contracts(1)</i>				
Fair value of derivative instruments—current . . .	\$ 8,698	\$4,345	\$ (90,551)	\$ (65,489)
Fair value of derivative instruments—long-term	16,092	417	(65,403)	(66,290)
Total	\$24,790	\$4,762	\$(155,954)	\$(131,779)

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

<u>Derivative contracts not designated as hedging instruments and the location of gain or (loss) recognized in income</u>	Year ended December 31,		
	2011	2010	2009
<i>Revenue: Derivative loss</i>			
Realized (loss) gain	\$(48,093)	\$(33,560)	\$ 87,289
Unrealized gain (loss)	19,058	(20,372)	(207,641)
Total revenue: derivative loss	(29,035)	(53,932)	(120,352)
<i>Derivative loss related to purchased product costs</i>			
Realized loss	(27,711)	(21,909)	(53,052)
Unrealized loss	(25,249)	(5,804)	(15,831)
Total derivative loss related to purchase product costs	(52,960)	(27,713)	(68,883)
<i>Derivative gain related to facility expenses</i>			
Unrealized gain	6,480	1,295	373
<i>Derivative gain related to interest expense</i>			
Realized gain	—	2,380	2,000
Unrealized (loss) gain	—	(509)	509
Total derivative gain related to interest expense	—	1,871	2,509
<i>Miscellaneous income, net</i>			
Unrealized gain	—	190	336
Total loss	\$(75,515)	\$(78,289)	\$(186,017)

At December 31, 2011 and 2010, the fair value of the Partnership's commodity derivative contracts is inclusive of premium payments of zero and \$4.4 million, net of amortization, respectively. For 2011, 2010 and 2009, the *Realized (loss) gain—revenue* includes amortization of premium payments of \$4.4 million, \$3.3 million and \$5.7 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

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

6. Derivative Financial Instruments (Continued)

counterparties, and as such does not represent trading activity. The settlement was recorded as \$26.5 million of realized gains in *Revenue: Derivative loss* and \$11.3 million of loss included in *Derivative loss related to purchased product costs* in the accompanying Consolidated Statements of Operations.

Volume of Derivative Activity

As of December 31, 2011, the Partnership had the following outstanding commodity contracts that were executed to manage the cash flow risk associated with future sales of NGLs or future purchases of natural gas.

<u>Derivative contracts not designated as hedging instruments</u>	<u>Position</u>	<u>Notional Quantity (net)</u>
Crude Oil (bbl)	Short	8,244,902
Natural Gas (MMBtu)	Long	16,021,887
NGLs (gal)	Short	86,563,841

Embedded Derivatives in Commodity Contracts

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. This contract is accounted for as an embedded derivative and is recorded at fair value. The changes in fair value of this commodity contract are based on the difference between the contractual and index pricing and are recorded in earnings through *Derivative loss related to purchased product costs*. In February 2011, the Partnership executed agreements with the producer to extend the commodity contract and the related processing agreement from March 31, 2015 to December 31, 2022, with the producer's option to extend the agreement for successive five year terms through December 31, 2032. As of December 31, 2011, the estimated fair value of this contract was a liability of \$114.9 million and the recorded value was a liability of \$61.4 million. The recorded liability does not include the inception fair value of the commodity contract related to the extended period from April 1, 2015 to December 31, 2022. In accordance with GAAP for non-option embedded derivatives, the fair value of this extended portion of the commodity contract at its inception of February 1, 2011 is deemed to be allocable to the host processing contract and, therefore, not recorded as a derivative liability. See the following table for a reconciliation of the liability recorded for the embedded derivative as of December 31, 2011 (in thousands).

Fair value of commodity contract	\$114,928
Inception value for period from April 1, 2015 to December 31, 2022.	(53,507)
Derivative liability as of December 31, 2011	<u>\$ 61,421</u>

The Partnership has a commodity contract that gives it an option to fix a component of the utilities cost to an index price on electricity at its plant location in the Gulf Coast segment through the fourth quarter of 2014. Changes in the fair value of the derivative component of this contract are recognized as *Derivative gain related to facility expenses*. As of December 31, 2011 and 2010, the estimated fair value of this contract was an asset of \$7.5 million and \$1.0 million, respectively.

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

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, PEPL 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, 2011 and 2010, and by the valuation hierarchy (in thousands):

<u>As of December 31, 2011</u>	<u>Assets</u>	<u>Liabilities</u>
<i>Significant other observable inputs (Level 2)</i>		
Commodity contracts	\$ 5,063	\$ (79,358)
<i>Significant unobservable inputs (Level 3)</i>		
Commodity contracts	12,210	(15,175)
Embedded derivatives in commodity contracts	7,517	(61,421)
Total carrying value in Consolidated Balance Sheet	<u>\$24,790</u>	<u>\$(155,954)</u>
<u>As of December 31, 2010</u>	<u>Assets</u>	<u>Liabilities</u>
<i>Significant other observable inputs (Level 2)</i>		
Commodity contracts	\$ 52	\$ (77,776)
<i>Significant unobservable inputs (Level 3)</i>		
Commodity contracts	3,674	(18,031)
Embedded derivatives in commodity contracts	1,036	(35,972)
Total carrying value in Consolidated Balance Sheet	<u>\$4,762</u>	<u>\$(131,779)</u>

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

7. Fair Value (Continued)

Changes in Level 3 Fair Value Measurements

The tables below include a rollforward of the balance sheet amounts for the years ended December 31, 2011 and 2010 (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, 2011	
	Commodity Derivative Contracts (net)	Embedded Derivatives in Commodity Contracts (net)
Fair value at beginning of period	\$(14,357)	\$(34,936)
Total gain or loss (realized and unrealized) included in earnings(1)	3,182	(30,827)
Settlements	8,210	11,859
Fair value at end of period	\$ (2,965)	\$(53,904)
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 end of period . . .	\$ 6,241	\$(29,556)

	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)	\$ —	\$ —

(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* and *Derivative gain 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*.

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

7. Fair Value (Continued)

Assets and liabilities measured at fair value on a nonrecurring basis

Certain assets and liabilities are remeasured 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. During 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 in 2009. 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 2009 impairment. During the three years ended December 31, 2011, 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, 2011, 2010 and 2009, revenues from a single customer totaled \$297.8 million, \$198.6 million and \$134.8 million, representing 19.4%, 16.0% and 15.7% of *Revenue*, respectively. Revenues from this customer are for NGL sales made primarily in the Southwest segment. As of December 31, 2011 and 2010, the Partnership had \$8.0 million and \$5.1 million of accounts receivable from this customer, respectively.

For the years ended December 31, 2011, 2010 and 2009, revenues from another customer totaled \$203.3 million, \$115.0 million and \$81.6 million, representing 13.2%, 9.3% and 9.5% of *Revenue*, respectively. Revenues from this customer are for NGL sales made primarily from the Southwest segment. As of December 31, 2011 and 2010, the Partnership had \$21.9 million and \$13.1 million of accounts receivable from this customer, respectively.

9. Receivables

Receivables consist of the following (in thousands):

	<u>December 31, 2011</u>	<u>December 31, 2010</u>
Trade, net	\$221,343	\$174,216
Other	5,218	4,993
Total receivables	<u>\$226,561</u>	<u>\$179,209</u>

10. Inventories

Inventories consist of the following (in thousands):

	<u>December 31, 2011</u>	<u>December 31, 2010</u>
NGLs	\$32,352	\$15,930
Spare parts, materials and supplies	8,654	7,502
Total inventories	<u>\$41,006</u>	<u>\$23,432</u>

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

11. Property, Plant and Equipment

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

	<u>December 31, 2011</u>	<u>December 31, 2010</u>
Natural gas gathering and NGL transportation pipelines and facilities	\$2,039,524	\$1,625,170
Processing plants	660,928	584,886
Fractionation and storage facilities	120,474	81,317
Crude oil pipelines	16,678	16,810
Land, building, office equipment and other	185,462	155,437
Construction in progress	279,303	149,407
Property, plant and equipment	3,302,369	2,613,027
Less: accumulated depreciation	(438,062)	(294,003)
Total property, plant and equipment, net	<u>\$2,864,307</u>	<u>\$2,319,024</u>

12. Goodwill and Intangible Assets

Goodwill. The table below shows the gross amount of goodwill acquired and the cumulative impairment loss recognized as of December 31, 2011 (in thousands). There was no activity related to goodwill during 2009 or 2010.

	<u>Southwest</u>	<u>Northeast</u>	<u>Gulf Coast</u>	<u>Total</u>
Gross goodwill as of December 31, 2010	\$ 24,324	\$ 3,948	\$ 9,854	\$ 38,126
Acquisition(1)	—	58,497	—	58,497
Gross Goodwill as of December 31, 2011	24,324	62,445	9,854	96,623
Cumulative impairment(2)	(18,851)	—	(9,854)	(28,705)
Balance as of December 31, 2011	<u>\$ 5,473</u>	<u>\$62,445</u>	<u>\$ —</u>	<u>\$ 67,918</u>

(1) Represents goodwill associated with the Langley Acquisition (see Note 3).

(2) All impairments recorded in the fourth quarter of 2008.

Intangible Assets. The Partnership's intangible assets as of December 31, 2011 and 2010 are comprised of customer contracts and relationships, as follows (in thousands):

<u>Description</u>	<u>December 31, 2011</u>			<u>December 31, 2010</u>			<u>Useful Life</u>
	<u>Gross</u>	<u>Accumulated Amortization</u>	<u>Net</u>	<u>Gross</u>	<u>Accumulated Amortization</u>	<u>Net</u>	
Southwest	\$406,690	\$ (92,340)	\$314,350	\$406,801	\$ (69,655)	\$337,146	10 - 20 yrs
Northeast	102,473	(29,037)	73,436	68,573	(19,590)	48,983	12 yrs
Gulf Coast	262,772	(46,791)	215,981	262,772	(35,323)	227,449	20 - 25 yrs
Total	<u>\$771,935</u>	<u>\$(168,168)</u>	<u>\$603,767</u>	<u>\$738,146</u>	<u>\$(124,568)</u>	<u>\$613,578</u>	

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

12. Goodwill and Intangible Assets (Continued)

Estimated future amortization expense related to the intangible assets at December 31, 2011 is as follows (in thousands):

<u>Year ending December 31,</u>	
2012	\$ 43,940
2013	43,940
2014	43,940
2015	43,940
2016	43,940
Thereafter	<u>384,067</u>
	<u>\$603,767</u>

13. Impairment of 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 a segment level and at lower levels where cash flows for specific assets can be identified.

An analysis completed during 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 expense.

14. Accrued Liabilities and Other Long-Term Liabilities

Accrued liabilities as of December 31, 2011 and 2010 consist of the following (in thousands):

	<u>December 31, 2011</u>	<u>December 31, 2010</u>
Accrued property, plant and equipment	\$ 87,098	\$ 65,908
Interest	27,458	26,607
Product and operations	22,969	31,241
Employee compensation	12,600	9,167
Taxes (other than income tax)	9,914	8,670
Other	<u>11,412</u>	<u>12,276</u>
Total accrued liabilities	<u>\$171,451</u>	<u>\$153,869</u>

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

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

Other long-term liabilities as of December 31, 2011 and 2010 consist of the following (in thousands):

	<u>December 31, 2011</u>	<u>December 31, 2010</u>
SMR Liability (see Note 5)	\$ 91,851	\$ 93,909
Deferred revenue	19,383	4,018
Asset retirement obligation	6,818	4,029
Other	3,304	3,393
Total other long-term liabilities	<u>\$121,356</u>	<u>\$105,349</u>

15. 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, 2010 to December 31, 2011 (in thousands):

	<u>December 31, 2011</u>	<u>December 31, 2010</u>
Beginning asset retirement obligation	\$4,029	\$2,877
Liabilities incurred	1,599	915
Accretion expense	1,190	237
Ending asset retirement obligation	<u>\$6,818</u>	<u>\$4,029</u>

At December 31, 2011, 2010 and 2009, 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.

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

16. Long-Term Debt

Debt is summarized below (in thousands):

	<u>December 31, 2011</u>	<u>December 31, 2010</u>
Credit Facility		
Revolving credit facility, 4.0% interest due September 2016	\$ 66,000	\$ —
Senior Notes		
2016 Senior Notes, 8.5% interest, net of discount of \$0 and \$642, respectively, issued July 2006 and due July 2016	—	274,358
2018 Senior Notes, 8.75% interest, net of discount of \$129 and \$924, respectively, issued April and May 2008 and due April 2018	80,983	499,076
2020 Senior Notes, 6.75% interest, issued November 2010 and due November 2020	500,000	500,000
2021 Senior Notes, 6.5% interest, net of discount of \$921, issued February and March 2011 and due August 2021	499,079	—
2022 Senior Notes, 6.25% interest, issued October 2011 and due June 2022	700,000	—
Total long-term debt	<u>\$1,846,062</u>	<u>\$1,273,434</u>

Credit Facility

The Partnership's Credit Facility has a current lending capacity of \$900 million and provides for an uncommitted accordion feature whereby the Credit Facility may be increased from time to time by the Partnership upon the satisfaction of certain requirements by up to an aggregate of \$250 million. The Credit Facility matures on September 7, 2016. The Partnership incurred approximately \$2.1 million, \$11.2 million, and \$4.4 million of deferred financing costs associated with modifications of the Credit Facility during the years ended December 31, 2011, 2010 and 2009, respectively.

The borrowings under the Credit Facility bear interest at a variable interest rate, plus basis points. The variable interest rate is based either on the London interbank market rate ("LIBO Rate Loans"), or the higher of (a) the prime rate set by the Facility's administrative agent, (b) the Federal Funds Rate plus 0.50% and (c) the rate for LIBO Rate Loans for a one month interest period plus 1% ("Alternate Base Rate Loans"). The basis points correspond to the Partnership's Total Leverage Ratio (which is the ratio of the Partnership's consolidated funded debt to the Partnership's adjusted consolidated EBITDA), ranging from 0.75% to 1.75% for Alternate Base Rate Loans and from 1.75% to 2.75% for LIBO Rate 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.

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

16. Long-Term Debt (Continued)

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, 2011, 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 by the Partnership's wholly-owned subsidiaries other than MarkWest Liberty Midstream and collateralized by substantially all of the Partnership's assets and those of its wholly-owned subsidiaries other than MarkWest Liberty Midstream. As of December 31, 2011, the Partnership had \$66.0 million of borrowings outstanding and \$19.3 million of letters of credit outstanding under the Credit Facility, leaving approximately \$814.7 million available for borrowing.

Senior Notes

As of December 31, 2011, MarkWest Energy Partners, L.P. in conjunction with its wholly-owned subsidiary MarkWest Energy Finance Corporation (the "Issuers"), had the following series of senior notes outstanding: \$81.1 million aggregate principal issued in April and May 2008 and due in April 2018; \$500.0 million aggregate principal issued in November 2010 and due in November 2020; \$500.0 million aggregate principal issued in February and March 2011, due August 2021; and \$700.0 million of Senior aggregate principal issued in November 2011, due June 2022.

2014 Senior Notes. In October 2004, the Issuers completed a private placement, subsequently registered, of \$225 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. In May 2009, the Issuers completed an additional private placement, subsequently registered, of \$150 million in aggregate principal amount of 6.875% senior unsecured notes to qualified institutional buyers under Rule 144A under an indenture substantially similar to the indenture relating to the notes issued in October 2004. The 2014 Senior Notes were redeemed in the fourth quarter of 2010.

2016 Senior Notes. In July and October 2006, the Issuers completed a private placement, subsequently registered, of \$275 million in aggregate principal amount of 8.5% senior unsecured notes due 2016 ("2016 Senior Notes") to qualified institutional buyers. The 2016 Senior Notes were redeemed in the first and third quarters of 2011.

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 unsecured 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. In May 2008, the Partnership completed the placement of an additional \$100 million pursuant to the indenture to the 2018 Senior Notes. The notes issued in the April 2008 and May 2008 offerings are treated a single class of debt under this same indenture. The Partnership received combined proceeds of approximately \$488.5 million, after including initial purchasers' premium and deducting the underwriting fees and the other expenses of the offering. Approximately \$253.3 million and \$165.6 million of the 2018 Senior Notes were redeemed in the fourth quarter and first quarter of 2011, respectfully.

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

16. Long-Term Debt (Continued)

2020 Senior Notes. In November 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.

2021 Senior Notes. On February 24, 2011, the Issuers completed a public offering of \$300 million in aggregate principal amount of 6.5% senior unsecured notes, which were issued at par. On March 10, 2011, the Issuers completed a follow-on public offering of an additional \$200 million in aggregate principal amount of 2021 Senior Notes, which were issued at 99.5% of par and are treated as a single class of debt securities under the same indenture as the 2021 Senior Notes issued on February 24, 2011. 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 aggregate net proceeds of approximately \$492 million from the 2021 Senior Notes offerings after deducting the underwriting fees and other third-party expenses associated with the offerings.

2022 Senior Notes. On November 3, 2011, the Issuers completed a public offering of \$700 million in aggregate principal amount of 6.25% senior unsecured notes due June 2022. Interest on the 2022 Notes is payable semi-annually in arrears on June 15 and December 15, commencing June 15, 2012. The Partnership received aggregate net proceeds of approximately \$688 million from the 2022 Senior Notes offerings, after deducting the underwriting fees and other third-party expenses.

The proceeds from the issuance of the 2021 and 2022 Senior Notes were used to redeem \$275 million of 2016 Senior Notes and \$419 million of 2018 Senior Notes and to provide additional working capital for general partnership purposes. The proceeds from the issuance of the 2020 Senior Notes were used to redeem the 2014 Senior Notes, repay the Credit Facility and to provide additional working capital for general partnership purposes.

The Partnership recorded a total pre-tax loss of approximately \$79.0 million during 2011 related to the redemption of the 2016 Senior Notes and 2018 Senior Notes. The pre-tax loss consisted of approximately \$7.6 million related to the non-cash write-off of the unamortized discount and deferred finance costs and approximately \$71.4 million related to the payment of tender premiums and third party expenses. The loss is recorded in *Loss on redemption of debt* in the accompanying Consolidated Statements of Operations.

The Partnership recorded a total pre-tax loss of approximately \$46.3 million in the fourth quarter of 2010 related to the redemption of the senior notes issued in October 2004 and May 2009. The pre-tax loss consisted 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. The loss is recorded in *Loss on redemption of debt* in the accompanying Consolidated Statements of Operations.

The Issuers have no independent operating assets or operations. All wholly-owned subsidiaries, other than MarkWest Energy Finance Corporation and MarkWest Liberty Midstream, 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 25 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

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

16. Long-Term Debt (Continued)

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 Credit Facility.

The indentures governing the Senior Notes limit the activity of the Partnership and the restricted subsidiaries identified in the indentures. 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 terminate, in which case the Partnership and its subsidiaries will cease to be subject to such terminated covenants.

As of December 31, 2011, there are no minimum principal payments on Senior Notes due during the next five years. The full \$1,781 million principal amounts for Senior Notes are due between 2018 and 2022. The \$66 million of borrowings outstanding under the Credit Facility as of December 31, 2011 is due in 2016.

17. Equity

The Partnership Agreement stipulates the circumstances under which the Partnership is authorized to issue new capital, maintain capital accounts and distribute cash and 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 up to the next four quarters.

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

17. Equity (Continued)

The quarterly cash distributions applicable to 2011, 2010 and 2009 were as follows:

<u>Quarter Ended</u>	<u>Distribution Per Common Unit</u>	<u>Declaration Date</u>	<u>Record Date</u>	<u>Payment Date</u>
December 31, 2011	\$0.76	January 26, 2012	February 6, 2012	February 14, 2012
September 30, 2011	\$0.73	October 18, 2011	November 7, 2011	November 14, 2011
June 30, 2011	\$0.70	July 21, 2011	August 1, 2011	August 12, 2011
March 31, 2011	\$0.67	April 21, 2011	May 2, 2011	May 13, 2011
December 31, 2010	\$0.65	January 27, 2011	February 7, 2011	February 14, 2011
September 30, 2010	\$0.64	October 27, 2010	November 8, 2010	November 12, 2010
June 30, 2010	\$0.64	July 22, 2010	August 2, 2010	August 13, 2010
March 31, 2010	\$0.64	April 22, 2010	May 3, 2010	May 14, 2010
December 31, 2009	\$0.64	January 26, 2010	February 5, 2010	February 12, 2010
September 30, 2009	\$0.64	October 22, 2009	November 2, 2009	November 13, 2009
June 30, 2009	\$0.64	July 23, 2009	August 3, 2009	August 14, 2009
March 31, 2009	\$0.64	April 23, 2009	May 4, 2009	May 15, 2009

Equity Offerings

On June 10, 2009, the Partnership completed a public offering of approximately 3.34 million newly issued common units representing limited partner interests, which includes the full exercise of the underwriters' over-allotment option. Net proceeds after deducting underwriters' fees and other third-party expenses were approximately \$57.7 million.

On August 18, 2009, the Partnership completed a public offering of approximately 6.03 million newly issued common units representing limited partner interests, which includes the full exercise of the underwriters' over-allotment option. Net proceeds after deducting underwriters' fees and other third-party expenses were approximately \$120.9 million.

On April 6, 2010, the Partnership 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. Net proceeds after deducting underwriters' fees and other third-party expenses were approximately \$142.3 million.

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 underwriter's over-allotment option. Net proceeds after deducting underwriter's fees and other third-party expenses were approximately \$138.2 million and were used to partially fund the ongoing capital expenditure program, including a portion of the costs associated with the Langley Acquisition.

On July 13, 2011, the Partnership completed a public offering of approximately 4.0 million newly issued common units representing limited partner interests, which includes the full exercise of the underwriters' over-allotment option. Net proceeds after deducting underwriters' fees and other third-party expenses were approximately \$185.1 million.

On October 13, 2011, the Partnership completed a public offering of approximately 5.75 million newly issued common units representing limited partner interests, which includes the full exercise of the

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

17. Equity (Continued)

underwriters' over-allotment option. Net proceeds after deducting underwriters' fees and other third-party expenses were approximately \$251 million.

On December 19, 2011, we completed a public offering of 10.0 million newly issued common units representing limited partner interests. Total net proceeds of approximately \$521 million were used to partially fund the cash consideration to acquire the remaining 49% interest in MarkWest Liberty Midstream. On January 13, 2012, we issued an additional 0.7 million units to cover the exercise of the underwriters' over-allotment option. Total net proceeds of approximately \$38 million were used to fund our growth capital program.

Net proceeds from equity offerings, unless specifically identified otherwise, were used to repay borrowings under the Credit Facility and to provide working capital for general partnership purposes.

Class B Units Issuance

The Partnership issued approximately 19,954,000 Class B units to M&R as part of our acquisition of the non-controlling interest in MarkWest Liberty Midstream which was effective December 31, 2011. See Note 4 for further discussion of the acquisition. The Class B units will convert to common units on a one-for-one basis in five equal installments beginning on July 1, 2013 and each of the first four anniversaries of such date. Class B units (i) are not entitled to participate in any distributions of available cash prior to their conversion and (ii) 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) other than those matters that disproportionately and adversely affect the rights and preferences of the Class B units. Upon conversion of the Class B units, M&R's right to vote as a common unitholder of the Partnership will be limited to a maximum of 5% of the Partnership's outstanding Common Units. Once converted, M&R has the right to participate in underwritten offerings undertaken by the Partnership up to 20% of the total number of common units offered. M&R also has limited rights to distribute an aggregate of 2,500,000 common units to its members and their limited partners beginning in 2016, and EMG Liberty and certain of its affiliates will have the right to demand that we conduct up to three underwritten offerings beginning in 2017, but restricted to no more than one offering in any twelve-month period. Except as described above, M&R is not permitted to transfer its Class B units or Converted Units without the prior written consent of the Board.

18. 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

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

18. Commitments and Contingencies (Continued)

financial statements and that none of these actions, either individually or in the aggregate, will have a material adverse effect on our financial condition, liquidity or results of operation.

In June 2006, the Pipeline and Hazardous Materials Safety Administration 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. In March 2011, MarkWest received an order assessing a penalty solely against Equitable for count one of the NOPV in the amount of \$0.5 million and assessing a penalty jointly and severally against MarkWest and Equitable for four of the other counts in the NOPV in the amount of \$0.2 million. In March 2011, the parties filed separate petitions for reconsideration. In January 2012, the Agency issued an order that dismissed the penalty assessed solely against Equitable but retained the \$0.2 million penalty assessed jointly and severally against MarkWest and Equitable. MarkWest did not appeal the Agency’s decision and paid the entire penalty.

Contract Contingencies

Certain natural gas processing arrangements in our Liberty and Northeast segments require the Partnership to construct new natural gas processing plants and NGL pipelines and contain certain fees and charges if specified construction milestones are not achieved for reasons other than force majeure. The Partnership has experienced a couple of months’ delays in the construction of one processing facility in our Liberty Segment due to inabilities or delays in obtaining requisite permits, as well as due to extreme weather events. The requisite permits have subsequently been issued and construction has re-commenced. Delay charges could be up to \$1.0 million for each month (pro-rated for partial months) that the Partnership does not achieve certain intermediate and final completion construction milestones, other than delays due to force majeure. The Partnership currently estimates the construction completion dates of the processing plant will occur approximately two months after the milestone dates specified in the applicable agreement, but the Partnership has made a force majeure claim as the delays were a direct result of permit delays and weather which are force majeure events under the applicable contract. The customer has reserved its rights to dispute the claim, but the Partnership’s management believes it has a convincing legal position and believes that it is unlikely that its force majeure claim would not prevail if contested.

Lease and Other Contractual Obligations

The Partnership has various non-cancellable operating lease agreements and a long-term propane storage agreement expiring at various times through fiscal year 2040. Annual expense under these agreements was \$15.0 million, \$18.4 million and \$18.6 million for the years ended December 31, 2011,

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

18. Commitments and Contingencies (Continued)

2010 and 2009, respectively. The minimum future payments under these agreements as of December 31, 2011 are as follows (in thousands):

<u>Year ending December 31,</u>	
2012	\$10,299
2013	8,688
2014	7,793
2015	7,606
2016	7,334
2017 and thereafter	<u>17,663</u>
	<u>\$59,383</u>

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 is 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):

<u>Year ending December 31,</u>	
2012	\$ 17,412
2013	17,412
2014	17,412
2015	17,412
2016	17,412
2017 and thereafter	<u>230,029</u>
Total minimum payments	317,089
Less: Services element	121,295
Less: Interest	<u>101,885</u>
Total SMR liability	93,909
Less: Current portion of SMR Liability	<u>2,058</u>
Long-term portion of SMR Liability	<u>\$ 91,851</u>

19. Lease Operations

Based on the terms of certain natural gas gathering, transportation, and processing 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.

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

19. Lease Operations (Continued)

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. Another significant implicit lease relates to natural gas processing agreement in the Northeast segment for which the Partnership earns a minimum monthly fee for providing processing services to a single producer using a dedicated processing plant. The primary term of the natural gas processing agreement expires in 2022 and may be extended at the option of the producer for up to two successive five year terms.

The Partnership's revenue from its implicit lease arrangements, excluding executory costs, totaled approximately \$67.4 million, \$32.2 million and \$14.9 million for the years ended December 31, 2011, 2010 and 2009, respectively. The Partnership's implicit lease arrangements do not contain any significant contingent rental provisions. The following is a schedule of minimum future rentals on the non-cancellable operating leases as of December 31, 2011 (in thousands):

<u>Year ending December 31,</u>	
2012	\$ 61,081
2013	61,081
2014	61,081
2015	59,794
2016	59,794
2017 and thereafter	<u>352,760</u>
Total minimum future rentals	<u>\$655,591</u>

The following schedule provides an analysis of the Partnership's investment in assets held for operating lease by major classes as of December 31, 2011 and 2010 (in thousands):

	<u>December 31, 2011</u>	<u>December 31, 2010</u>
Natural gas gathering and NGL transportation pipelines and facilities	\$479,567	\$264,669
Construction in progress	<u>38,386</u>	<u>60,170</u>
Property, plant and equipment	517,953	324,839
Less: accumulated depreciation	<u>(46,006)</u>	<u>(21,742)</u>
Total property, plant and equipment, net	<u>\$471,947</u>	<u>\$303,097</u>

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

20. Incentive Compensation Plans

The following table summarizes the share-based compensation plans administered by the Compensation Committee of the Board (“Compensation Committee”) that were active during the periods presented in the accompanying Consolidated Statements of Operations:

<u>Share-based compensation plan</u>	<u>Award Classification</u>	<u>Further awards authorized for issuance under plan as of December 31, 2011</u>	<u>Awards outstanding under the plan as of December 31, 2011</u>	<u>Final Year of Activity</u>
2008 Long-Term Incentive Plan (“2008 LTIP”)	Equity	Yes	Yes	N/A
2006 Hydrocarbon Stock Incentive Plan (“2006 Hydrocarbon Plan”)	Equity	No	No	2010
Long-Term Incentive Plan (“2002 LTIP”)	Liability	No	No	2011
1996 Hydrocarbon Stock Incentive Plan (“1996 Hydrocarbon Plan”)	Equity	No	No	2009

Compensation Expense

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

	<u>Year ended December 31,</u>		
	<u>2011</u>	<u>2010</u>	<u>2009</u>
Phantom units	\$13,479	\$15,319	\$7,448
Distribution equivalent rights(1)	446	1,465	1,324
Total compensation expense	<u>\$13,925</u>	<u>\$16,784</u>	<u>\$8,772</u>

(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.

As of December 31, 2011, total compensation expense not yet recognized related to the unvested awards under the 2008 LTIP was approximately \$12.1 million, with a weighted average remaining vesting period of approximately 0.8 years. Total compensation expense not yet recognized includes approximately \$0.2 million related to the TSR Performance Units (see discussion of TSR Performance Units below).

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

20. Incentive Compensation Plans (Continued)

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.

TSR Performance Units. In April 2010, the Board granted 282,000 performance phantom units ("TSR Performance Units") under the 2008 LTIP to senior executives and other key employees. The TSR Performance Units are classified as equity awards and do not contain distribution equivalent rights. The TSR Performance Units were scheduled to vest in 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 ("Market Criteria"). Zero TSR Performance Units vest if the Partnership's relative ranking is less than the 40th percentile; 50% of the TSR Performance Units vest if the Partnership's relative ranking is in the 40th to 60th percentile; 75% of the TSR Performance Units vest if the Partnership's relative ranking is in the 60th to 80th percentile; and 100% of the TSR Performance Units 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 on the Performance Criteria. In January 2011 and 2012, 141,000 TSR performance vested based on the Market Criteria and the Board exercised its discretion to issue and immediately vest an additional 35,250 units.

The effect of vesting conditions is that 75% of the TSR Performance Units vested based solely on the Partnership's actual performance with regards to the Market Criteria. The remaining 25% of the TSR Performance Units vested based on a combination of the Market Criteria and the Performance Criteria. Compensation expense related to the TSR Performance Units that vested solely based on the Market Criteria was 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, was not established for the TSR Performance Units that vest based on a combination of the Market Criteria and Performance Criteria until the Board exercised its discretion because the Performance Criteria prevents a mutual understanding of the key terms of the award. Therefore, compensation expense related to this portion of the TSR Performance Units was recognized over the requisite service period based on the fair value of the units as of each reporting date. The requisite service period for all TSR Performance Units began in April 2010 when the Board approved the awards. TSR Compensation expense recognized related to TSR Performance Units was approximately \$4.8 million and \$4.5 million for the years ended December 31, 2011 and 2010, respectively.

The fair value of the TSR Performance Units was measured at each appropriate measurement date using a Monte Carlo simulation model that estimated 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

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

20. Incentive Compensation Plans (Continued)

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.

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") were granted to senior executives and other key employees under the 2008 LTIP in 2008 and 2009. The Performance Units vest on a performance-based schedule over a three-year period, and vesting of these units occurs if the Partnership achieves established financial performance goals determined by the Compensation Committee. Management conducts an analysis on an ongoing basis to assess the probability of meeting the established performance goals and records compensation expense as required. As of December 31, 2011, there are 141,000 Performance Units outstanding with a grant date fair value of \$1.2 million. The outstanding Performance Units did not vest. Compensation expense recorded for the Performance Units expected to vest was zero for the years ended December 31, 2011 and 2010, and approximately \$0.5 million year ended December 31, 2009.

2006 Hydrocarbon Plan and 1996 Hydrocarbon Plan

On February 21, 2008, the 25,897 outstanding shares of restricted stock granted under the 2006 Hydrocarbon Plan and 1996 Hydrocarbon Plan were converted to 49,354 phantom units in connection with the Merger. The converted phantom unit awards remained outstanding under the terms of the 2006 Hydrocarbon Plan and 1996 Hydrocarbon Plan until their respective settlement dates. The last converted phantom units outstanding under the 2006 Hydrocarbon Plan or the 1996 Hydrocarbon Plan vested on January 31, 2010 and 2009, respectively.

Summary of Equity Awards

Awards under the 2008 LTIP, and historically the 2006 Hydrocarbon Plan and the 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. Phantom unit awards generally vest in equal tranches over a three-year period. For service-based awards, compensation expense related to each tranche is recognized over its requisite service period, reduced for an estimate of expected forfeitures. 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 assumes 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 \$6.0 million, \$3.4 million, and \$1.1 million during the years ended December 31, 2011, 2010 and 2009, 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.

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

20. Incentive Compensation Plans (Continued)

The following is a summary of all phantom unit activity under the 2008 LTIP, 2006 Hydrocarbon Plan and 1996 Hydrocarbon Plan for the years ended December 31, 2011, 2010 and 2009:

	Number of Units	Weighted-average Grant-date Fair Value(1)
Unvested at January 1, 2009	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 (includes 282,000 TSR units)	736,688	30.25
Vested	(363,502)	26.85
Forfeited	(21,267)	19.28
Unvested at December 31, 2010 (includes 282,000 TSR units)	1,329,160	25.29
Granted (includes 35,250 TSR units)	309,629	42.75
Vested (includes 176,250 TSR units)	(396,934)	27.04
Forfeited	(306,346)	31.66
Unvested at December 31, 2011 (includes 141,000 TSR units)(2)	<u>935,509</u>	28.50

(1) The calculation of the weighted average grant-date fair value for units granted during the year ended December 31, 2010 and unvested as of December 2010 and December 2011 is recalculated to include the fair value as of December 31, 2011 for 35,250 TSR Performance Units. A grant date, as defined by GAAP, has not been established for these units.

(2) Includes 141,000 Performance Units that did not vest and were forfeited in January 2012.

The total fair value and intrinsic value of the phantom units vested under the 2008 LTIP was \$10.7 million, \$9.8 million, and \$9.9 million during the years ended December 31, 2011, 2010, and 2009, respectively. The total fair value and intrinsic value of the TSR Performance Units vested during the year ended December 31, 2011 was \$4.9 million.

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 assumes the income tax withholding obligations related to the vesting. The Partnership

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

20. Incentive Compensation Plans (Continued)

received no proceeds 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, \$0.4 million and \$0.2 million for the years ended December 31, 2011, 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, 2009	145,927	\$31.45
Vested	(69,652)	29.94
Forfeited	(6,720)	33.64
Unvested at December 31, 2009	69,555	32.75
Vested	(44,942)	32.15
Forfeited	(968)	34.00
Unvested at December 31, 2010	23,645	33.83
Vested	(23,645)	33.83
Unvested at December 31, 2011	—	—

The total fair value and intrinsic value of the phantom units vested under the 2002 LTIP was \$1.0 million, \$1.3 million, and \$0.9 million during the years ended December 31, 2011, 2010, and 2009, respectively.

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 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. Additional paid-in capital 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.

21. 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 \$2.7 million, \$2.3 million and \$1.8 million for the years ended December 31, 2011, 2010 and 2009, respectively.

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

22. Income Tax

As discussed in Note 2, all changes in the tax bases of assets and liabilities are allocated among continued operations and items charged or credited directly to equity. During the fourth quarter of 2011, the Partnership determined it had understated its deferred tax liability related to its investment in consolidated subsidiaries for timing differences created as a result of items charged or credited directly to equity. The Partnership evaluated the materiality of the error from a qualitative and quantitative perspective and concluded that the error was not material to any prior period.

In the accompanying *Consolidated Balance Sheet* as of December 31, 2010, the correction of the error discussed above results in an increase in long-term deferred tax liabilities and a corresponding decrease in equity of \$77.5 million as compared to the amounts previously reported. In the accompanying *Consolidated Statement of Changes in Equity*, the correction resulted in a cumulative decrease in the balances associated with common units and total equity of \$77.5 million, \$69.8 million, and \$59.6 million as of December 31, 2010, 2009, and 2008, respectively. This cumulative adjustment gives effect to the *Deferred tax impact of equity transactions*, which was previously not reported, of \$7.6 million and \$10.2 million for the years ended December 31, 2010 and 2009, respectively.

The components of the provision for income tax expense (benefit) are as follows (in thousands):

	Year ended December 31,		
	2011	2010	2009
Current income tax expense:			
Federal	\$15,039	\$ 5,850	\$ 6,525
State	2,539	1,805	1,547
Total current	<u>17,578</u>	<u>7,655</u>	<u>8,072</u>
Deferred income tax (benefit) expense:			
Federal	(4,732)	(3,870)	(43,409)
State	803	(596)	(6,679)
Total deferred	<u>(3,929)</u>	<u>(4,466)</u>	<u>(50,088)</u>
Provision for income tax	<u>\$13,649</u>	<u>\$ 3,189</u>	<u>\$(42,016)</u>

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

22. 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, 2011, 2010 and 2009 is as follows (in thousands):

Year ended December 31, 2011:

	<u>Corporation</u>	<u>Partnership</u>	<u>Eliminations</u>	<u>Consolidated</u>
Income before provision for income tax. . .	\$ 3,813	\$124,087	\$(8,006)	<u>\$119,894</u>
Federal statutory rate	35%	0%	0%	
Federal income tax at statutory rate	1,335	—	—	1,335
Permanent items	36	—	—	36
State income taxes net of federal benefit . .	102	2,742	—	2,844
Current year change in valuation allowance .	(64)	—	—	(64)
Prior period adjustments and tax rate changes	163	—	—	163
Provision on income from Class A units(1) .	9,323	—	—	9,323
Other	12	—	—	12
Provision for income tax	<u>\$10,907</u>	<u>\$ 2,742</u>	<u>\$ —</u>	<u>\$ 13,649</u>

Year ended December 31, 2010:

	<u>Corporation</u>	<u>Partnership</u>	<u>Eliminations</u>	<u>Consolidated</u>
(Loss) income before provision for income tax	\$(8,120)	\$47,761	\$(5,350)	<u>\$34,291</u>
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	<u>\$ 1,890</u>	<u>\$ 1,299</u>	<u>\$ —</u>	<u>\$ 3,189</u>

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

22. Income Tax (Continued)

Year ended December 31, 2009:

	<u>Corporation</u>	<u>Partnership</u>	<u>Eliminations</u>	<u>Consolidated</u>
Loss before provision for income tax	\$(112,506)	\$(32,800)	\$(10,064)	<u>\$(155,370)</u>
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	<u>\$ (40,577)</u>	<u>\$ (1,439)</u>	<u>\$ —</u>	<u>\$ (42,016)</u>

(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. This amount includes intra period allocations to continued operations and excludes allocations to equity.

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

22. Income Tax (Continued)

The deferred tax assets and liabilities resulting from temporary book-tax differences are comprised of the following (in thousands):

	<u>December 31,</u>	
	<u>2011</u>	<u>2010</u>
Current deferred tax assets:		
Accruals and reserves	\$ 78	\$ 64
Derivative instruments	14,807	16,031
Current deferred tax assets	<u>14,885</u>	<u>16,095</u>
Current deferred tax liabilities:		
Derivative instruments	—	16
Current deferred tax liabilities	—	16
Current subtotal	<u>14,885</u>	<u>16,079</u>
Long-term deferred tax assets:		
Accruals and reserves	48	34
Derivative instruments	20,301	14,241
Phantom unit compensation	2,103	1,684
Capital loss carryforward	971	975
State net operating loss carryforward	101	156
Long-term deferred tax assets	<u>23,524</u>	<u>17,090</u>
Valuation allowance	(977)	(1,036)
Net long-term deferred tax assets	<u>22,547</u>	<u>16,054</u>
Long-term deferred tax liabilities:		
Property, plant and equipment and intangibles	2,123	3,529
Phantom unit compensation	—	31
Investment in affiliated groups	114,088	100,345
Derivative instruments	—	30
Long-term deferred tax liabilities	<u>116,211</u>	<u>103,935</u>
Long-term subtotal	<u>(93,664)</u>	<u>(87,881)</u>
Net deferred tax liability	<u><u>\$ (78,779)</u></u>	<u><u>\$ (71,802)</u></u>

Significant judgment is required in evaluating tax positions and determining the Corporation's provision for income taxes. During the ordinary course of business, there may be transactions and calculations for which the ultimate tax determination is uncertain. However, the Corporation did not have any material uncertain tax positions for the years ended December 31, 2011, 2010 or 2009. As of December 31, 2011, the Corporation had state net operating loss carryforwards of approximately \$0.1 million that expire between 2024 and 2027. 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

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

22. Income Tax (Continued)

December 31, 2011, 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 2010 remain open to examination by the major taxing jurisdictions to which the Corporation is subject.

23. Earnings (Loss) 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, 2011, 2010 and 2009, respectively, and the weighted average units used to compute diluted net (loss) income per common unit (in thousands, except per unit data):

	<u>Year ended December 31,</u>		
	<u>2011(2)</u>	<u>2010</u>	<u>2009</u>
Net income (loss) attributable to the Partnership . . .	\$60,695	\$ 467	\$(118,668)
Less: Income allocable to phantom units	1,749	1,308	1,518
Income (loss) available for common unitholders	<u>\$58,946</u>	<u>\$ (841)</u>	<u>\$(120,186)</u>
Weighted average common units outstanding—basic .	78,466	70,128	60,957
Effect of dilutive instruments(1)	153	—	—
Weighted average common units outstanding— diluted	<u>78,619</u>	<u>70,128</u>	<u>60,957</u>
Net income (loss) attributable to the Partnership's common unitholders per common unit:			
Basic	<u>\$ 0.75</u>	<u>\$ (0.01)</u>	<u>\$ (1.97)</u>
Diluted	<u>\$ 0.75</u>	<u>\$ (0.01)</u>	<u>\$ (1.97)</u>

- (1) For the years ended December 31, 2011 and 2010, dilutive instruments include TSR Phantom Units and are based on the number of units, if any, that would be issuable at the end of the respective reporting 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 20 for further discussion of TSR Phantom Units.
- (2) The Class B units had no impact to the earnings per unit calculation as they were issued on December 31, 2011 and as such were not outstanding for any portion of the fiscal year and were not allocated any of the *Net income (loss) attributable to the Partnership*.

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

24. 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 the following 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 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. Segment results are also adjusted to exclude the portion of operating income attributable to the non-controlling interests.

The tables below present information about operating income and capital expenditures for the reported segments for the years ended December 31, 2011, 2010 and 2009 (in thousands).

Year ended December 31, 2011:

	<u>Southwest</u>	<u>Northeast</u>	<u>Liberty</u>	<u>Gulf Coast</u>	<u>Total</u>
Segment revenue	\$935,513	\$268,884	\$248,949	\$96,473	\$1,549,819
Purchased product costs	<u>506,911</u>	<u>91,612</u>	<u>83,847</u>	<u>—</u>	<u>682,370</u>
Net operating margin	428,602	177,272	165,102	96,473	867,449
Facility expenses	82,761	27,126	34,913	38,436	183,236
Portion of operating income attributable to non-controlling interests	<u>5,431</u>	<u>—</u>	<u>63,731</u>	<u>—</u>	<u>69,162</u>
Operating income before items not allocated to segments	<u>\$340,410</u>	<u>\$150,146</u>	<u>\$ 66,458</u>	<u>\$58,037</u>	<u>\$ 615,051</u>
Capital expenditures	\$103,968	\$ 51,280	\$388,850	\$ 2,093	\$ 546,191
Capital expenditures not allocated to segment					5,090
Total capital expenditures					<u>\$ 551,281</u>

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

24. Segment Information (Continued)

Year ended December 31, 2010:

	<u>Southwest</u>	<u>Northeast</u>	<u>Liberty</u>	<u>Gulf Coast</u>	<u>Total</u>
Segment 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	<u>\$268,596</u>	<u>\$112,384</u>	<u>\$ 38,917</u>	<u>\$51,823</u>	<u>\$ 471,720</u>
Capital expenditures	\$114,109	\$ 2,179	\$332,793	\$ 3,947	\$ 453,028
Capital expenditures not allocated to segments					5,640
Total capital expenditures					<u>\$ 458,668</u>

Year ended December 31, 2009:

	<u>Southwest</u>	<u>Northeast</u>	<u>Liberty</u>	<u>Gulf Coast</u>	<u>Total</u>
Segment 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	<u>\$195,114</u>	<u>\$ 64,864</u>	<u>\$ 12,584</u>	<u>\$41,675</u>	<u>\$314,237</u>
Capital expenditures	\$236,705	\$ 21,538	\$181,142	\$40,606	\$479,991
Capital expenditures not allocated to segments					6,632
Total capital expenditures					<u>\$486,623</u>

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

24. 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, 2011, 2010 and 2009 (in thousands):

	Year ended December 31,		
	2011	2010	2009
Total segment revenue	\$1,549,819	\$1,241,563	\$ 858,635
Derivative loss not allocated to segments	(29,035)	(53,932)	(120,352)
Revenue deferral adjustment(1)	(15,385)	—	—
Total revenue	<u>\$1,505,399</u>	<u>\$1,187,631</u>	<u>\$ 738,283</u>
Operating income before items not allocated to segments	\$ 615,051	\$ 471,720	\$ 314,237
Portion of operating income attributable to non-controlling interests	69,162	32,566	9,250
Derivative loss not allocated to segments	(75,515)	(80,350)	(188,862)
Revenue deferral adjustment(1)	(15,385)	—	—
Compensation expense included in facility expenses not allocated to segments	(1,781)	(1,890)	(1,032)
Facility expenses adjustments(2)	11,419	9,091	377
Selling, general and administrative expenses	(81,229)	(75,258)	(63,728)
Depreciation	(149,954)	(123,198)	(95,537)
Amortization of intangible assets	(43,617)	(40,833)	(40,831)
Loss on disposal of property, plant and equipment	(8,797)	(3,149)	(1,677)
Accretion of asset retirement obligations	(1,190)	(237)	(198)
Impairment of goodwill and long-lived assets	—	—	(5,855)
Income (loss) from operations	318,164	188,462	(73,856)
(Loss) earnings from unconsolidated affiliates	(1,095)	1,562	3,505
Gain on sale of unconsolidated affiliate	—	—	6,801
Interest income	422	1,670	349
Interest expense	(113,631)	(103,873)	(87,419)
Amortization of deferred financing costs and discount (a component of interest expense)	(5,114)	(10,264)	(9,718)
Derivative gain related to interest expense	—	1,871	2,509
Loss on redemption of debt	(78,996)	(46,326)	—
Miscellaneous income, net	144	1,189	2,459
Income (loss) before provision for income tax	<u>\$ 119,894</u>	<u>\$ 34,291</u>	<u>\$(155,370)</u>

(1) Amount relates to certain contracts in which the cash consideration that the Partnership receives for providing service is greater during the initial years of the contract compared to the later years. In accordance with GAAP, the revenue is recognized evenly over the term of the contract as the Partnership expects to perform a similar level of service for the entire term; therefore, the revenue recognized in the current reporting period is less than the cash received. However, the chief operating decision maker and management evaluate the segment performance based on the cash consideration received and, therefore, the impact of the revenue deferrals is excluded for segment reporting purposes. For the year ended December 31, 2011, approximately \$7.2 million and

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

24. Segment Information (Continued)

\$8.2 million of the revenue deferral adjustment is attributable to the Southwest segment and Northeast segment, respectively. Beginning in 2015, the cash consideration received from these contracts is expected to decline and the reported segment revenue will be less than the revenue recognized for GAAP purposes.

- (2) 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. The increase is due to a full year of interest expense related to the SMR in 2011 compared to approximately nine months of SMR interest expense in 2010.

The tables below present information about segment assets as of December 31, 2011, 2010, and 2009 (in thousands):

	<u>December 31, 2011</u>	<u>December 31, 2010</u>	<u>December 31, 2009</u>
Southwest	\$1,701,919	\$1,646,607	\$1,637,749
Northeast	533,591	244,219	249,804
Liberty	1,114,654	743,943	373,127
Gulf Coast	553,043	573,456	587,830
Total segment assets	<u>3,903,207</u>	<u>3,208,225</u>	<u>2,848,510</u>
Assets not allocated to segments:			
Certain cash and cash equivalents	66,212	49,776	73,184
Fair value of derivatives	24,790	4,762	24,631
Investment in unconsolidated affiliate	27,853	28,688	29,633
Other(1)	48,363	41,911	38,779
Total assets	<u>\$4,070,425</u>	<u>\$3,333,362</u>	<u>\$3,014,737</u>

- (1) As of December 31, 2011, includes corporate fixed assets, deferred financing costs, income tax receivable, deferred tax asset and other corporate assets not allocated to segments. As of December 31, 2010 and 2009, includes corporate fixed assets, deferred financing costs, income tax receivable, receivables and other corporate assets not allocated to segments.

25. Supplemental Condensed Consolidating Financial Information

MarkWest Energy Partners has no significant operations independent of its subsidiaries. As of December 31, 2011, the Partnership's obligations under the outstanding Senior Notes (see Note 16) were fully, jointly and severally guaranteed, by all of its wholly-owned subsidiaries other than MarkWest Liberty Midstream. The guarantees are unconditional except for certain customary circumstances in which a subsidiary would be released from the guarantee under the indentures. 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

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

25. Supplemental Condensed Consolidating Financial Information (Continued)

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. Condensed consolidating financial information for MarkWest Energy Partners and its combined guarantor and combined non-guarantor subsidiaries as of

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

25. Supplemental Condensed Consolidating Financial Information (Continued)

December 31, 2011 and 2010 and for the years ended December 31, 2011, 2010 and 2009 is as follows (in thousands):

Condensed Consolidating Balance Sheets

	As of December 31, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	\$ 22	\$ 99,580	\$ 17,414	\$ —	\$ 117,016
Restricted cash	—	—	26,193	—	26,193
Receivables and other current assets	7,097	232,010	55,098	(5)	294,200
Intercompany receivables	19,981	40,519	22,193	(82,693)	—
Fair value of derivative instruments	—	8,015	683	—	8,698
Total current assets	27,100	380,124	121,581	(82,698)	446,107
Total property, plant and equipment, net	4,012	1,714,857	1,163,226	(17,788)	2,864,307
Other long-term assets:					
Investment in unconsolidated affiliate	—	27,853	—	—	27,853
Investment in consolidated affiliates	3,071,124	1,097,350	—	(4,168,474)	—
Intangibles, net of accumulated amortization	—	603,224	543	—	603,767
Fair value of derivative instruments	—	16,092	—	—	16,092
Intercompany notes receivable	235,700	—	—	(235,700)	—
Other long-term assets	41,492	70,434	373	—	112,299
Total assets(1)	<u>\$3,379,428</u>	<u>\$3,909,934</u>	<u>\$1,285,723</u>	<u>\$(4,504,660)</u>	<u>\$4,070,425</u>
LIABILITIES AND EQUITY					
Current liabilities:					
Intercompany payables	\$ 40,503	\$ 40,374	\$ 1,816	\$ (82,693)	\$ —
Fair value of derivative instruments	—	90,551	—	—	90,551
Other current liabilities	38,775	219,622	92,930	(5)	351,322
Total current liabilities	79,278	350,547	94,746	(82,698)	441,873
Deferred income taxes	1,228	92,436	—	—	93,664
Intercompany notes payable	—	212,700	23,000	(235,700)	—
Fair value of derivative instruments	—	65,403	—	—	65,403
Long-term debt, net of discounts	1,846,062	—	—	—	1,846,062
Other long-term liabilities	3,232	117,724	400	—	121,356
Equity:					
Common Units	697,097	3,071,124	1,167,577	(4,256,489)	679,309
Class B Units	752,531	—	—	—	752,531
Non-controlling interest in consolidated subsidiaries	—	—	—	70,227	70,227
Total equity	<u>1,449,628</u>	<u>3,071,124</u>	<u>1,167,577</u>	<u>(4,186,262)</u>	<u>1,502,067</u>
Total liabilities and equity	<u>\$3,379,428</u>	<u>\$3,909,934</u>	<u>\$1,285,723</u>	<u>\$(4,504,660)</u>	<u>\$4,070,425</u>

(1) In accordance with the December 2011 amendment to the Partnership's Credit Facility, certain assets in the Liberty segment included in *Total property, plant, and equipment, net* are expected to be contributed from a non-guarantor subsidiary to a guarantor subsidiary by April 2012. The contributed assets would include only the natural gas processing facilities at the Partnership's Houston Complex and any other equipment related solely to these processing facilities.

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

25. Supplemental Condensed Consolidating Financial Information (Continued)

	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	639,219	368,864	—	(1,008,083)	—
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	<u>\$2,316,149</u>	<u>\$2,777,374</u>	<u>\$905,928</u>	<u>\$(2,666,089)</u>	<u>\$3,333,362</u>
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	85,348	—	—	87,881
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:					
Common Units	1,004,309	639,219	834,381	(1,484,860)	993,049
Non-controlling interest in consolidated subsidiaries	—	—	—	465,517	465,517
Total equity	1,004,309	639,219	834,381	(1,019,343)	1,458,566
Total liabilities and equity	<u>\$2,316,149</u>	<u>\$2,777,374</u>	<u>\$905,928</u>	<u>\$(2,666,089)</u>	<u>\$3,333,362</u>

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

25. Supplemental Condensed Consolidating Financial Information (Continued)

Condensed Consolidating Statements of Operations

	Year ended December 31, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue	\$ —	\$1,240,004	\$265,395	\$ —	\$1,505,399
Operating expenses:					
Purchased product costs	—	651,132	84,198	—	735,330
Facility expenses	—	128,612	39,171	(665)	167,118
Selling, general and administrative expenses	46,903	31,015	9,011	(5,700)	81,229
Depreciation and amortization	719	151,362	42,198	(708)	193,571
Other operating expenses	673	9,030	284	—	9,987
Total operating expenses	<u>48,295</u>	<u>971,151</u>	<u>174,862</u>	<u>(7,073)</u>	<u>1,187,235</u>
(Loss) income from operations	(48,295)	268,853	90,533	7,073	318,164
Earnings from consolidated affiliates	288,870	44,425	—	(333,295)	—
Loss on redemption of debt	(78,996)	—	—	—	(78,996)
Other expense, net	<u>(91,612)</u>	<u>(13,501)</u>	<u>(558)</u>	<u>(13,603)</u>	<u>(119,274)</u>
Income before provision for income tax	69,967	299,777	89,975	(339,825)	119,894
Provision for income tax expense	<u>2,742</u>	<u>10,907</u>	<u>—</u>	<u>—</u>	<u>13,649</u>
Net income	67,225	288,870	89,975	(339,825)	106,245
Net income attributable to non-controlling interest	<u>—</u>	<u>—</u>	<u>—</u>	<u>(45,550)</u>	<u>(45,550)</u>
Net income attributable to the Partnership	<u>\$ 67,225</u>	<u>\$ 288,870</u>	<u>\$ 89,975</u>	<u>\$(385,375)</u>	<u>\$ 60,695</u>

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

25. Supplemental Condensed Consolidating Financial Information (Continued)

	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	<u>47,896</u>	<u>878,105</u>	<u>79,165</u>	<u>(5,997)</u>	<u>999,169</u>
(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	<u>(82,000)</u>	<u>(16,032)</u>	<u>1,753</u>	<u>(11,566)</u>	<u>(107,845)</u>
Income before provision for income tax	7,335	185,447	46,598	(205,089)	34,291
Provision for income tax expense	<u>1,299</u>	<u>1,890</u>	<u>—</u>	<u>—</u>	<u>3,189</u>
Net income	6,036	183,557	46,598	(205,089)	31,102
Net income attributable to non-controlling interest	<u>—</u>	<u>—</u>	<u>—</u>	<u>(30,635)</u>	<u>(30,635)</u>
Net income attributable to the Partnership	<u>\$ 6,036</u>	<u>\$ 183,557</u>	<u>\$ 46,598</u>	<u>\$(235,724)</u>	<u>\$ 467</u>

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

25. 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	<u>46,715</u>	<u>720,284</u>	<u>49,125</u>	<u>(3,985)</u>	<u>812,139</u>
(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	<u>(69,951)</u>	<u>(12,692)</u>	<u>3,997</u>	<u>(9,669)</u>	<u>(88,315)</u>
(Loss) income before provision for income tax	(114,423)	(38,334)	6,815	(9,428)	(155,370)
Provision for income tax benefit	<u>(1,439)</u>	<u>(40,577)</u>	<u>—</u>	<u>—</u>	<u>(42,016)</u>
Net (loss) income	(112,984)	2,243	6,815	(9,428)	(113,354)
Net income attributable to non-controlling interest	<u>—</u>	<u>—</u>	<u>—</u>	<u>(5,314)</u>	<u>(5,314)</u>
Net (loss) income attributable to the Partnership	<u>\$ (112,984)</u>	<u>\$ 2,243</u>	<u>\$ 6,815</u>	<u>\$ (14,742)</u>	<u>\$ (118,668)</u>

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

25. Supplemental Condensed Consolidating Financial Information (Continued)

Condensed Consolidating Statements of Cash Flows

	Year ended December 31, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net cash (used in) provided by operating activities	\$ (126,782)	\$ 410,762	\$ 137,961	\$ (7,243)	\$ 414,698
Cash flows from investing activities:					
Restricted cash	—	—	2,006	—	2,006
Capital expenditures	(789)	(162,517)	(399,992)	12,017	(551,281)
Acquisitions	—	(230,728)	—	—	(230,728)
Equity investments	(47,295)	(252,367)	—	299,662	—
Distributions from consolidated affiliates	50,718	68,651	—	(119,369)	—
Investment in intercompany notes, net	(37,990)	—	—	37,990	—
Proceeds from disposal of property, plant and equipment	—	606	7,617	(4,773)	3,450
Net cash flows used in investing activities	(35,356)	(576,355)	(390,369)	225,527	(776,553)
Cash flows from financing activities:					
Proceeds from revolving credit facility	1,182,200	—	—	—	1,182,200
Payments of revolving credit facility	(1,116,200)	—	—	—	(1,116,200)
Proceeds from long-term debt	1,199,000	—	—	—	1,199,000
Payments of long-term debt	(693,888)	—	—	—	(693,888)
Payments of premiums on redemption of long-term debt	(71,377)	—	—	—	(71,377)
Proceeds from intercompany notes, net	—	14,990	23,000	(37,990)	—
Payments for debt issuance costs, deferred financing costs and registration costs	(20,163)	—	—	—	(20,163)
Acquisition of non-controlling interest, including transaction costs	(997,601)	—	—	—	(997,601)
Contributions from parent, net	—	47,295	—	(47,295)	—
Contributions to joint ventures, net	—	—	378,759	(252,367)	126,392
Payments of SMR Liability	—	(1,875)	—	—	(1,875)
Proceeds from public equity offerings, net	1,095,488	—	—	—	1,095,488
Share-based payment activity	(6,354)	1,084	—	—	(5,270)
Payment of distributions	(218,398)	(50,718)	(135,537)	119,368	(285,285)
Intercompany advances, net	(190,547)	190,547	—	—	—
Net cash flows provided by financing activities	162,160	201,323	266,222	(218,284)	411,421
Net increase in cash	22	35,730	13,814	—	49,566
Cash and cash equivalents at beginning of year	—	63,850	3,600	—	67,450
Cash and cash equivalents at end of period	<u>\$ 22</u>	<u>\$ 99,580</u>	<u>\$ 17,414</u>	<u>\$ —</u>	<u>\$ 117,016</u>

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

25. Supplemental Condensed Consolidating Financial Information (Continued)

	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 equity 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

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

25. 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	<u>(18,722)</u>	<u>(218,289)</u>	<u>(281,285)</u>	<u>56,543</u>	<u>(461,753)</u>
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	<u>117,575</u>	<u>(29,803)</u>	<u>296,019</u>	<u>(50,708)</u>	<u>333,083</u>
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	<u>\$ —</u>	<u>\$ 74,448</u>	<u>\$ 23,304</u>	<u>\$ —</u>	<u>\$ 97,752</u>

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

26. Supplemental Cash Flow Information

The following table provides information regarding supplemental cash flow information (in thousands):

	<u>Year ended December 31,</u>		
	<u>2011</u>	<u>2010</u>	<u>2009</u>
Supplemental disclosures of cash flow information:			
Cash paid for interest, net of amounts capitalized	\$112,780	\$101,459	\$85,817
Cash paid for income taxes, net of refunds	10,115	8,683	4,609
Supplemental schedule of non-cash investing and financing activities:			
Accrued property, plant and equipment	\$ 87,098	\$ 65,908	\$60,738
Interest capitalized on construction in progress	1,121	2,766	12,228
Issuance of common units for vesting of share-based payment awards	5,412	7,238	9,402
Issuance of Class B units for acquisition of non-controlling interest	752,531	—	—

27. Valuation and Qualifying Accounts

Activity in the Partnership's allowance for doubtful accounts and deferred tax asset valuation allowance is as follows (in thousands):

	<u>Year ended December 31,</u>		
	<u>2011</u>	<u>2010</u>	<u>2009</u>
<i>Allowance for Doubtful Accounts</i>			
Balance at beginning of period	\$ 162	\$ 162	\$ 175
Charged to costs and expenses	—	134	12
Other charges(1)	(2)	(134)	(25)
Balance at end of period	<u>\$ 160</u>	<u>\$ 162</u>	<u>\$ 162</u>
<i>Deferred Tax Asset Valuation Allowance</i>			
Balance at beginning of period	\$1,036	\$1,688	\$ 30
Charged to costs and expenses	(59)	(652)	1,667
Other charges	—	—	(9)
Balance at end of period	<u>\$ 977</u>	<u>\$1,036</u>	<u>\$1,688</u>

(1) Bad debts written-off (net of recoveries).

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

28. Quarterly Results of Operations (Unaudited)

The following summarizes the Partnership's quarterly results of operations for 2011 and 2010 (in thousands, except per unit data):

	Three months ended			
	March 31(1)	June 30	September 30	December 31(2)
2011				
Total revenue	\$263,221	\$400,439	\$507,826	\$333,913
(Loss) income from operations	(15,294)	133,214	207,801	(7,557)
Net (loss) income	(74,671)	89,205	153,454	(61,743)
Net (loss) income attributable to the Partnership	(84,029)	78,497	140,312	(74,085)
Net (loss) income attributable to the Partnership's common unitholders per common unit(4):				
Basic	\$ (1.13)	\$ 1.03	\$ 1.77	\$ (0.87)
Diluted	\$ (1.13)	\$ 1.03	\$ 1.77	\$ (0.87)
	Three months ended			
	March 31	June 30	September 30	December 31(3)
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(4):				
Basic	\$ 0.32	\$ 0.84	\$ (0.39)	\$ (0.76)
Diluted	\$ 0.32	\$ 0.84	\$ (0.39)	\$ (0.76)

- (1) During the first quarter of 2011, the Partnership recorded a loss on redemption of debt of approximately \$43.3 million related to the repurchase of the 2016 Senior Notes and a portion of 2018 Senior Notes. See Note 16 for further details.
- (2) During the fourth quarter of 2011, the Partnership recorded a loss on redemption of debt of approximately \$35.5 million related to the repurchase of a portion of the 2018 Senior Notes. See Note 16 for further details.
- (3) 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 the 2014 Senior Notes. See Note 16 for further details.
- (4) 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.

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

29. Subsequent Events

Utica Shale Joint Venture

Effective January 1, 2012, the Partnership and EMG Utica entered into the Utica Joint Venture to develop significant natural gas processing and NGL fractionation, transportation and marketing infrastructure in the Utica Shale in eastern Ohio beginning in 2012. Under the terms of the Utica Joint Venture, EMG will fund a majority of the initial capital expenditures required to develop the Utica midstream infrastructure. The Partnership has a 60% ownership in the Utica Joint Venture. A wholly-owned subsidiary of the Partnership serves as the operator of MarkWest Utica EMG and provides field operating and general and administrative services. A portion of the fee for providing these services is fixed.

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, 2011. Based on this evaluation, the Partnership's management, including our Chief Executive Officer and Chief Financial Officer, concluded that as of December 31, 2011, 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, 2011 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, 2011, 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, 2011 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, 2011 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, 2011, 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, 2011 of the Partnership and our report dated February 28, 2012 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 28, 2012

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 April 29, 2012.

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 2012 Annual Meeting of Unitholders expected to be filed no later than April 29, 2012.

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 April 29, 2012.

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 April 29, 2012.

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 2012 Annual Meeting of Unitholders expected to be filed no later than April 29, 2012.

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(6)	Agreement and Plan of Redemption and Merger dated September 5, 2007 by and among MarkWest Hydrocarbon, Inc., MarkWest Energy Partners, L.P. and MWERP, 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(10)	Third Amended and Restated Agreement of Limited Partnership of MarkWest Energy Partners, L.P., dated as of February 21, 2008.
3.7(20)	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(20)	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(20)	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(20)	Amendment No. 4 to Amended and Restated Limited Liability Company Agreement MarkWest Energy GP, L.L.C., dated as of March 31, 2008.
3.11(27)	Amendment No. 1 to the Third Amended and Restated Agreement of Limited Partnership of MarkWest Energy Partners, L.P., dated December 29, 2011.
4.1(12)	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.
4.2(12)	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 4.1 hereto).
4.3(12)	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.
4.4(13)	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.
4.5(16)	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.

Exhibit Number	Description
4.6(16)	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.
4.7(16)	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.
4.8(17)	Indenture Release of Subsidiary Guarantor dated as of May 1, 2009, among MarkWest Energy Partners, L.P., and Wells Fargo Bank, N.A.
4.9(18)	Indenture Release of Subsidiary Guarantor dated as of October 31, 2009, among MarkWest Energy Partners, L.P. and Wells Fargo Bank, N.A.
4.10(28)	Fourth Supplemental Indenture dated as of March 10, 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.
4.11(32)	Fifth Supplemental Indenture dated as of October 21, 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.
4.12(34)	Sixth Supplemental Indenture, dated as of November 10, 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.
4.13(22)	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.
4.14(22)	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.
4.15(22)	Form of 6¾% Senior Notes due 2020 with attached notation of Guarantees (incorporated by reference to Exhibits A and B of Exhibit 4.14 hereto).
4.16(26)	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.
4.17(26)	Form of 6.5% Senior Notes due 2021 with attached notation of Guarantees (incorporated by reference to Exhibits A and B of Exhibit 4.16 hereto).
4.18(28)	Third Supplemental Indenture dated as of March 10, 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.
4.19(32)	Fourth Supplemental Indenture dated as of October 21, 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.
4.20(33)	Fifth Supplemental Indenture, dated as of November 3, 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.

Exhibit Number	Description
4.21(33)	Form of 6.25% Senior Notes due 2022 with attached notation of Guarantees (incorporated by reference to Exhibits A and B of Exhibit 4.20 hereto).
4.22*	Sixth Supplemental Indenture, dated as of December 27, 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.
4.23*	Registration Rights Agreement dated December 29, 2011 between MarkWest Energy Partners, L.P. and M&R MWE Liberty, LLC.
10.1(24)	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 Lender, 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(25)	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(29)	Joinder Agreement dated as of June 15, 2011 among MarkWest Energy Partners, L.P., Wells Fargo Bank, National Association, individually and as Administrative Agent, Issuing Bank and Swingline Lender and Citibank, N.A.
10.4(31)	First Amendment to Amended and Restated Credit Agreement dated as of September 7, 2011 among MarkWest Energy Partners, L.P., Wells Fargo Bank, National Association, as Administrative Agent, and the other agents and lenders party thereto.
10.5(27)	Second Amendment to Amended and Restated Credit Agreement dated as of December 29, 2011, among MarkWest Energy Partners, L.P., Wells Fargo Bank, National Association, as Administrative Agent, and the other agents and lenders party thereto.
10.6(3)	Services Agreement dated January 1, 2004 between MarkWest Energy GP, L.L.C. and MarkWest Hydrocarbon, Inc.
10.7(5)+	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.
10.8(7)+	Hydrogen Supply Agreement dated September 28, 2007, by and between MarkWest Blackhawk, L.P. and CITGO Refining and Chemicals Company L.P.
10.9(9)+	Gas Processing Agreement dated as of November 1, 2007, by and between MarkWest Javelina Company and CITGO Refining and Chemicals Company, L.P.
10.10(8)+	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.
10.11(15)+	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.
10.12(16)+	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.

Exhibit Number	Description
10.13(16)+	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.
10.14(16)+	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.
10.15(23)+	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.
10.16(19)+	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.
10.17(19)+	Amended and Restated Limited Liability Company Agreement of MarkWest Liberty Midstream & Resources, L.L.C. dated as of February 27, 2009.
10.18(21)+	Letter Agreement dated August 10, 2009 between MarkWest Liberty Gas Gathering, L.L.C. and M&R MWE Liberty, LLC.
10.19(23)+	Second Amended and Restated Limited Liability Company Agreement of MarkWest Liberty Midstream & Resources, L.L.C. dated as of November 1, 2009.
10.20(23)	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.
10.21(6)	Exchange Agreement dated September 5, 2007 by and among MarkWest Energy Partners, L.P., MarkWest Hydrocarbon, Inc., and MarkWest Energy, GP L.L.C.
10.22(14)	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.
10.23(2)	MarkWest Energy Partners, L.P. Long-Term Incentive Plan.
10.24(2)	First Amendment to MarkWest Energy Partners, L.P. Long-Term Incentive Plan.
10.25(14)	1996 Stock Incentive Plan for MarkWest Hydrocarbon, Inc.
10.26(14)	2006 Stock Incentive Plan for MarkWest Hydrocarbon, Inc.
10.27(11)	MarkWest Energy Partners, L.P. 2008 Long-Term Incentive Plan.
10.28(4)Δ	Executive Employment Agreement effective September 5, 2007 between MarkWest Hydrocarbon, Inc. and Frank Semple.

Exhibit Number	Description
10.29(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.
10.30(30)+	Amendment No. 2 to Second Amended and Restated Limited Liability Company Agreement of MarkWest Liberty Midstream & Resources, L.L.C. dated as of April 28, 2011.
10.31(28)+	Purchase and Sale Agreement dated as of January 3, 2011 by and between EQT Gathering, LLC and MarkWest Energy Appalachia, L.L.C.
10.32(28)+	Letter Agreement dated February 1, 2011 between EQT Gathering, LLC and MarkWest Energy Appalachia, L.L.C.
10.33*+	Amendment No. 3 to Second Amended and Restated Limited Liability Company Agreement of MarkWest Liberty Midstream & Resources, L.L.C. dated as of December 19, 2011, among MarkWest Liberty Midstream & Resources, L.L.C., MarkWest Liberty Gas Gathering, L.L.C. and M&R MWE Liberty, LLC.
10.34*+	Contribution Agreement dated December 29, 2011 among M&R MWE Liberty, LLC, MarkWest Energy Partners, L.P. and MarkWest Liberty Gas Gathering L.L.C.
10.35*+	Limited Liability Company Agreement of MarkWest Utica EMG, L.L.C., dated December 29, 2011 and effective January 1, 2012, between MarkWest Utica Operating Company, L.L.C. and EMG Utica, LLC.
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
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 Quarterly Report on Form 10-Q filed November 7, 2006.
 - (6) Incorporated by reference to the Current Report on Form 8-K filed September 6, 2007.
 - (7) Incorporated by reference to the Quarterly Report on Form 10-Q filed November 8, 2007.
 - (8) Incorporated by reference to the Annual Report on Form 10-K filed February 29, 2008.
 - (9) Incorporated by reference to the Annual Report on Form 10-K/A filed May 8, 2008.
 - (10) Incorporated by reference to the Current Report on Form 8-K filed February 21, 2008.
 - (11) Incorporated by reference to the Form S-4/A Registration Statement filed December 21, 2007.
 - (12) Incorporated by reference to the Current Report on Form 8-K filed April 15, 2008.
 - (13) Incorporated by reference to the Current Report on Form 8-K filed May 1, 2008.
 - (14) Incorporated by reference to the Quarterly Report on Form 10-Q filed August 11, 2008.
 - (15) Incorporated by reference to the Quarterly Report on Form 10-Q filed November 10, 2008.
 - (16) Incorporated by reference to the Annual Report on Form 10-K filed March 2, 2009.
 - (17) Incorporated by reference to the Quarterly Report on Form 10-Q filed August 10, 2009.
 - (18) Incorporated by reference to the Registration Statement on Form S-3 filed January 13, 2010.
 - (19) Incorporated by reference to the Quarterly Report on Form 10-Q/A filed October 16, 2009.
 - (20) Incorporated by reference to the Form S-4 Registration Statement filed July 2, 2009.
 - (21) Incorporated by reference to the Quarterly Report on Form 10-Q filed November 9, 2009.
 - (22) Incorporated by reference to the Current Report on Form 8-K filed November 3, 2010.
 - (23) Incorporated by reference to the Annual Report on Form 10-K filed March 1, 2010.
 - (24) Incorporated by reference to the Current Report on Form 8-K filed July 7, 2010.
 - (25) Incorporated by reference to the Current Report on Form 8-K filed August 4, 2010.
 - (26) Incorporated by reference to the Current Report on Form 8-K filed February 24, 2011.
 - (27) Incorporated by reference to the Current Report on Form 8-K filed December 30, 2011.
 - (28) Incorporated by reference to the Quarterly Report on Form 10-Q filed May 9, 2011.
 - (29) Incorporated by reference to the Current Report on Form 8-K filed June 17, 2011.
 - (30) Incorporated by reference to the Quarterly Report on Form 10-Q filed August 8, 2011.
 - (31) Incorporated by reference to the Current Report on Form 8-K filed September 13, 2011.
 - (32) Incorporated by reference to the Quarterly Report on Form 10-Q filed November 7, 2011.
 - (33) Incorporated by reference to the Current Report on Form 8-K filed November 7, 2011.
 - (34) Incorporated by reference to the Current Report on Form 8-K filed November 15, 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, 2012

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, 2012

By: /s/ FRANK M. SEMPLE
Frank M. Semple
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

Date: February 28, 2012

By: /s/ NANCY K. BUESE
Nancy K. Buese
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: February 28, 2012

By: /s/ PAULA L. ROSSON
Paula L. Rosson
Vice President and Chief Accounting Officer
(Principal Accounting Officer)

Date: February 28, 2012

By: /s/ DONALD D. WOLF
Donald D. Wolf
Lead Director

Date: February 28, 2012

By: /s/ KEITH E. BAILEY
Keith E. Bailey
Director

Date: February 28, 2012

By: /s/ MICHAEL L. BEATTY
 Michael L. Beatty
 Director

Date: February 28, 2012

By: /s/ CHARLES K. DEMPSTER
 Charles K. Dempster
 Director

Date: February 28, 2012

By: /s/ ANNE E. FOX MOUNSEY
 Anne E. Fox Mounsey
 Director

Date: February 28, 2012

By: /s/ DONALD C. HEPPERMAN
 Donald C. Heppermann
 Director

Date: February 28, 2012

By: /s/ WILLIAM A. KELLSTROM
 William A. Kellstrom
 Director

Date: February 28, 2012

By: /s/ WILLIAM P. NICOLETTI
 William P. Nicoletti
 Director

Date: February 28, 2012

By: /s/ RANDALL J. LARSON
 Randall J. Larson
 Director

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CORPORATE INFORMATION

BOARD OF DIRECTORS OF MARKWEST ENERGY GP, LLC

Frank M. Semple

Chairman of the Board, President and
Chief Executive Officer
MarkWest Energy GP, LLC

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 Finance Committee

Donald C. Heppermann

Chairman of the Finance Committee
Member of the Audit Committee

William A. Kellstrom

Member of the Nominating and
Corporate Governance Committee
Member of the Finance Committee

Randall J. Larson

Member of the Audit Committee
Member of the Compensation
Committee

Anne E. Fox Mounsey

Member of the Audit 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, LLC

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, LP
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 June 28, 2011.

MarkWest's Chief Executive Officer
and Chief Financial Officer have
provided certifications to the U.S.
Securities and Exchange Commission
as required by Sections 302 and 906
of the Sarbanes-Oxley Act of 2002.
These certifications are included as
Exhibits 31.1, 31.2, 32.1, and 32.2 to
the Partnership's Form 10-K for the
year ended December 31, 2011.

Our Core Principles

MarkWest believes that 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-in-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.

MarkWest Energy Partners' 2011 Annual Report saved the following resources by printing on paper containing recyclable fibers.



100 trees
preserved for
the future



32 million BTUs
of energy
not consumed



46,062 gallons
of wastewater
flow saved



2,797 pounds
of solid waste
not generated



9,564 pounds
net of greenhouse
gases prevented

FSC® is not responsible for any calculations on saving resources by choosing this paper.

1515 Arapahoe Street, Tower 1, Suite 1600
Denver, Colorado 80202-2137

www.markwest.com

