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

# FORM 10-Q

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

**For the quarterly period ended September 30, 2009**

**OR**

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

**For the transition period from to**

**Commission File Number 001-31239**

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

| | |
|---|---|
| **Delaware** | **27-0005456** |
| (State or other jurisdiction of incorporation or organization) | (IRS Employer Identification No.) |

**1515 Arapahoe Street, Tower 2, Suite 700, Denver, Colorado 80202-2126**
(Address of principal executive offices)

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

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

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

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

The number of the registrant's common units outstanding as of November 2, 2009, was 66,265,782.

Throughout this document we make statements that are classified as "forward-looking." Please refer to the "Forward-Looking Statements" included in Part I, Item 2 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. References to "MarkWest Hydrocarbon" or the "Corporation" are intended to mean MarkWest Hydrocarbon, Inc. prior to the redemption and merger completed on February 21, 2008.

**Glossary of Terms**

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

| | |
|---|---|
| Bbl/d | Barrels of oil per day |
| Btu | One British thermal unit, an energy measurement |
| Dth/d | Dekatherms per day |
| EBITDA | Earnings Before Interest, Taxes, Depreciation and Amortization |
| FERC | Federal Energy Regulatory Commission |
| FASB | Financial Accounting Standards Board |
| GAAP | Accounting principles generally accepted in the United States of America |
| Gal | Gallon |
| Gal/d | Gallons per day |
| LIBOR | London Interbank Offered Rate |
| Mcf/d | One thousand cubic feet of natural gas per day |
| Merger | On February 21, 2008, the Partnership completed the transactions contemplated by its plan of redemption and merger with MarkWest Hydrocarbon, Inc. and MWEP, L.L.C., a wholly-owned subsidiary of the Partnership. Refer to Note 3 of the Partnership's December 31, 2008 Annual Report on Form 10-K as modified by the Current Report on Form 8-K as filed with the SEC on May 18, 2009. |
| MMBtu | One million British thermal units, an energy measurement |
| MMBtu/d | One million British thermal units per day |
| MMcf/d | One million cubic feet of natural gas per day |
| Net operating margin (a non-GAAP financial measure) | Revenue, excluding any derivative gain (loss), less purchased product costs, excluding any derivative gain (loss) |
| NGL | Natural gas liquids, such as ethane, propane, butanes and natural gasoline |
| N/A | Not applicable |
| OTC | Over-the-Counter |
| SEC | Securities and Exchange Commission |
| 1996 Hydrocarbon Plan | 1996 Hydrocarbon Stock Incentive Plan |
| 2002 LTIP | Long-Term Incentive Plan |
| 2006 Hydrocarbon Plan | 2006 Hydrocarbon Stock Incentive Plan |
| 2008 LTIP | 2008 Long-Term Incentive Plan |

## PART I—FINANCIAL INFORMATION

### Item 1. Financial Statements

**MARKWEST ENERGY PARTNERS, L.P.**

**Condensed Consolidated Balance Sheets**

**(unaudited, in thousands)**

| | September 30, 2009 | December 31, 2008 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 65,306 | $ 3,321 |
| Receivables and other current assets | 163,203 | 145,153 |
| Fair value of derivative instruments | 17,796 | 126,949 |
| Total current assets | 246,305 | 275,423 |
| Property, plant and equipment | 2,003,400 | 1,650,692 |
| Less: accumulated depreciation | (148,244) | (81,167) |
| Total property, plant and equipment, net | 1,855,156 | 1,569,525 |
| Other long-term assets: | | |
| Intangibles, net of accumulated amortization of $73,542 and $42,972, respectively | 664,605 | 695,917 |
| Fair value of derivative instruments | 30,634 | 55,389 |
| Other long-term assets | 99,563 | 76,800 |
| Total other long-term assets | 794,802 | 828,106 |
| Total assets | $2,896,263 | $2,673,054 |
| **LIABILITIES AND PARTNERS' CAPITAL** | | |
| Current liabilities: | | |
| Fair value of derivative instruments | $ 35,134 | $ 37,633 |
| Other current liabilities | 175,522 | 186,553 |
| Total current liabilities | 210,656 | 224,186 |
| Deferred income taxes | 11,623 | 47,465 |
| Fair value of derivative instruments | 33,663 | 14,801 |
| Long-term debt, net of discounts of $41,548 and $11,735, respectively | 1,160,498 | 1,172,965 |
| Other long-term liabilities | 82,378 | 5,878 |
| Commitments and contingencies (Note 18) | | |
| Partners' Capital: | | |
| MarkWest Energy Partners, L.P. partners' capital (66,266 and 56,640 common units outstanding, respectively) | 1,163,494 | 1,204,458 |
| Non-controlling interest in consolidated subsidiaries | 233,951 | 3,301 |
| Total partners' capital | 1,397,445 | 1,207,759 |
| Total liabilities and partners' capital | $2,896,263 | $2,673,054 |

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

## MARKWEST ENERGY PARTNERS, L.P.
## Condensed Consolidated Statements of Operations
## (unaudited, in thousands, except per unit amounts)

| | Three months ended September 30, 2009 | Three months ended September 30, 2008 | Nine months ended September 30, 2009 | Nine months ended September 30, 2008 |
|---|---|---|---|---|
| Revenue: | | | | |
| Revenue | $207,933 | $303,560 | $ 576,300 | $866,760 |
| Derivative gain (loss) | 9,758 | 262,811 | (65,173) | (96,030) |
| Total revenue | 217,691 | 566,371 | 511,127 | 770,730 |
| Operating expenses: | | | | |
| Purchased product costs | 91,086 | 171,539 | 274,052 | 479,747 |
| Derivative loss (gain) related to purchased product costs | 7,816 | 67,574 | 39,954 | (11,520) |
| Facility expenses | 30,165 | 28,213 | 93,945 | 75,641 |
| Derivative loss related to facility expenses | 1,347 | 1,748 | 122 | 1,395 |
| Selling, general and administrative expenses | 15,477 | 15,331 | 46,265 | 54,406 |
| Depreciation | 25,264 | 17,510 | 69,621 | 48,533 |
| Amortization of intangible assets | 10,193 | 10,732 | 30,638 | 28,050 |
| Other operating expenses | 689 | 38 | 1,579 | 106 |
| Impairment of long-lived assets | — | — | 5,855 | 5,009 |
| Total operating expenses | 182,037 | 312,685 | 562,031 | 681,367 |
| Income (loss) from operations | 35,654 | 253,686 | (50,904) | 89,363 |
| Other income (expense): | | | | |
| Earnings (loss) from unconsolidated affiliates | 169 | (196) | 1,260 | 1,932 |
| Interest expense | (23,440) | (18,928) | (63,964) | (47,527) |
| Amortization of deferred financing costs and discount (a component of interest expense) | (3,091) | (1,080) | (6,528) | (7,287) |
| Derivative gain related to interest expense | 2,265 | — | 2,265 | — |
| Other income, net | 925 | 1,322 | 2,747 | 4,640 |
| Income (loss) before provision for income tax | 12,482 | 234,804 | (115,124) | 41,121 |
| Provision for income tax (benefit) expense: | | | | |
| Current | (46) | 7,544 | 6,530 | 22,876 |
| Deferred | 624 | 40,592 | (34,693) | (6,414) |
| Total provision for income tax | 578 | 48,136 | (28,163) | 16,462 |
| Net income (loss) | 11,904 | 186,668 | (86,961) | 24,659 |
| Net (income) loss attributable to non-controlling interest | (3,624) | (122) | (1,914) | 3,271 |
| Net income (loss) attributable to the Partnership | $ 8,280 | $186,546 | $ (88,875) | $ 27,930 |
| Net income (loss) attributable to the Partnership's common unitholders (Note 16): | | | | |
| Basic | $ 0.13 | $ 3.24 | $ (1.52) | $ 0.55 |
| Diluted | $ 0.13 | $ 3.24 | $ (1.52) | $ 0.55 |
| Weighted average number of outstanding common units: | | | | |
| Basic | 63,026 | 56,635 | 59,168 | 49,123 |
| Diluted | 63,026 | 56,635 | 59,168 | 49,127 |
| Cash distribution declared per common unit(1) | $ 0.64 | $ 0.63 | $ 1.92 | $ 1.42 |

(1) Under the Merger, the shareholders of the Corporation exchanged each share of Corporation common stock for consideration equal to 1.9051 Partnership common units (the "Exchange Ratio"). The first quarter 2008 distribution represents MarkWest Hydrocarbon's dividend as adjusted to reflect the Exchange Ratio to give effect to the Merger.

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

## MARKWEST ENERGY PARTNERS, L.P.

**Condensed Consolidated Statement of Changes in Partners' Capital**

**(unaudited, in thousands)**

| | MarkWest Energy Partners, L.P. Unitholders | | | |
|---|---|---|---|---|
| | **Common Units** | **Partners' Capital** | **Non-controlling Interest** | **Total** |
| **December 31, 2008** | 56,640 | $1,204,458 | $ 3,301 | $1,207,759 |
| Common units issued for vested phantom units | 266 | 648 | — | 648 |
| Distributions paid | — | (112,525) | (80) | (112,605) |
| Share-based compensation related to equity awards | — | 3,395 | — | 3,395 |
| Issuance of units in public offerings, net of offering costs | 9,360 | 178,632 | — | 178,632 |
| Contributions to MarkWest Liberty Midstream joint venture, net | — | (5,464) | 150,000 | 144,536 |
| Proceeds from sale of equity interest in joint venture, net | — | (1,847) | 62,500 | 60,653 |
| Transfer to non-controlling interest from sale of equity interest in joint venture, net of tax | — | (14,928) | 16,316 | 1,388 |
| Net (loss) income | — | (88,875) | 1,914 | (86,961) |
| **September 30, 2009** | 66,266 | $1,163,494 | $233,951 | $1,397,445 |

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

## MARKWEST ENERGY PARTNERS, L.P.

## Condensed Consolidated Statements of Cash Flows

## (unaudited, in thousands)

| | Nine months ended September 30, 2009 | Nine months ended September 30, 2008 |
|---|---|---|
| **Net cash provided by operating activities** | $ 147,865 | $ 216,132 |
| **Cash flows from investing activities:** | | |
| Change in restricted cash | (10,025) | — |
| Acquisitions | — | (41,300) |
| Equity investments | (6,435) | (27,038) |
| Cash paid to acquire General Partnership's minority interest | — | (21,484) |
| Cash paid in Merger for MarkWest Hydrocarbon, Inc. stock | — | (248,395) |
| Proceeds from sale of available for sale securities | — | 6,226 |
| Capital expenditures | (388,502) | (316,881) |
| Proceeds from disposal of property, plant and equipment | 275 | 78 |
| Net cash flows used in investing activities | (404,687) | (648,794) |
| **Cash flows from financing activities:** | | |
| Proceeds from long-term debt | 685,000 | 958,234 |
| Payments of long-term debt | (700,900) | (515,001) |
| Payments for debt issuance costs, deferred financing costs and registration costs | (8,381) | (21,213) |
| Proceeds from SMR transaction | 73,129 | — |
| Proceeds from public offerings, net | 178,632 | 171,395 |
| Contributions to MarkWest Liberty Midstream joint venture, net | 144,536 | — |
| Proceeds from sale of equity interest in joint venture, net | 60,653 | — |
| Share-based payment activity | (1,257) | 1,031 |
| Payment of distributions and dividends | (112,605) | (74,915) |
| Distributions to MarkWest Energy unitholders prior to the Merger | — | (19,651) |
| Net cash flows provided by financing activities | 318,807 | 499,880 |
| Net increase in cash | 61,985 | 67,218 |
| Cash and cash equivalents at beginning of year | 3,321 | 37,695 |
| Cash and cash equivalents at end of period | $ 65,306 | $ 104,913 |
| **Supplemental disclosures of cash flow information:** | | |
| Cash paid for interest, net of amounts capitalized | $ 51,514 | $ 29,558 |
| Cash paid for income taxes | 4,529 | 17,814 |
| **Supplemental schedule of non-cash investing and financing activities:** | | |
| Accrued property, plant and equipment | $ 24,322 | $ 67,826 |
| Interest capitalized on construction in progress | 9,262 | 5,035 |
| Property, plant and equipment asset retirement obligation | 821 | 9 |
| Merger step-up of fair value | — | 605,100 |
| Issuance of common units for vesting of share-based payment awards | 9,088 | 2,492 |

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

## 1. Organization and Basis of Presentation

MarkWest Energy Partners, L.P. was formed on January 25, 2002, as a Delaware limited partnership. The Partnership is 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 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 is the largest natural gas processor in the Appalachian region.

These unaudited condensed consolidated financial statements have been prepared in accordance with the rules and regulations of the SEC for interim financial reporting. Accordingly, certain information and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted. These condensed consolidated financial statements should be read in the context of the consolidated financial statements accompanying notes included in the Partnership's December 31, 2008 Annual Report on Form 10-K as modified by the Current Report on Form 8-K as filed with the SEC on May 18, 2009 for the retrospective application of changes to GAAP related to the presentation of non-controlling interest and the calculation of earnings per share. The presentation of the condensed consolidated statements has been updated to conform to the new requirements of GAAP. In management's opinion, the Partnership has made all adjustments necessary for a fair presentation of its results of operations, financial position and cash flows for the periods shown. These adjustments are of a normal recurring nature. Finally, consider that results for the three and nine months ended September 30, 2009 are not necessarily indicative of results for the full year 2009, or any other future period.

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

## 2. Significant Accounting Policies

There have not been any material changes during the nine months ended September 30, 2009 to the significant accounting policies previously disclosed in the Partnership's 2008 Annual Report on Form 10-K as modified by the Current Report on Form 8-K as filed with the SEC on May 18, 2009 except for the following items related to the accounting for regulated operations, interest rate swaps, and embedded derivatives related to long-term debt.

*Property, Plant and Equipment for FERC Regulated Assets*

Depreciation is generally computed over the asset's estimated useful life using the straight-line method. The composite weighted-average depreciation rates will be 4% for 2009. When the Partnership retires its regulated property, plant and equipment, the Partnership charges the original cost plus the cost of retirement, less salvage value, to accumulated depreciation and amortization.

**2. Significant Accounting Policies (Continued)**

*Allowance for Funds Used During Construction*

Allowance for funds used during construction ("AFUDC"), which represents the estimated debt and equity costs of capital funds necessary to finance the construction and expansion of regulated facilities, consists of an equity component and an interest expense component. The equity component is a non-cash item. AFUDC is capitalized as a component of *Property, plant and equipment*, with offsetting credits to the Condensed Consolidated Statements of Operations included in *Other income, net* for the equity component and *Interest expense* for the interest component. After construction is completed, the Partnership is permitted to recover these costs through inclusion in the rate base and in the depreciation provision. The total amount of AFUDC included in the Condensed Consolidated Statements of Operations was $5.0 million for the nine months ended September 30, 2009 (an equity component of $2.8 million and an interest expense component of $2.2 million).

*Interest Rate Swaps*

The fair value of the Partnership's interest rate swaps is included as an asset or liability under the caption *Fair value of derivative instruments* in the Condensed Consolidated Balance Sheets. Changes in the fair value of interest rate swaps are recorded through *Derivative gain related to interest expense* in the Condensed Consolidated Statements of Operations.

*Embedded Derivatives Related to Long-Term Debt*

The fair value of derivatives related to long-term debt is included as a component of *Long-term debt* in the Condensed Consolidated Balance Sheet. Changes in the fair value of embedded derivatives related to long-term debt are recorded through *Other income, net* in the Condensed Consolidated Statements of Operations (see Note 12).

**3. Recent Accounting Pronouncements**

In May 2009, the FASB established guidance for the account and reporting of subsequent events, which are events occurring after the balance sheet date but before the financial statements are issued or available to be issued. The new principles describe the circumstances that would require the Partnership to recognize the impact of subsequent events in its financial statements, provides disclosure requirements for subsequent events, and defines the period through which subsequent events must be evaluated. The guidance became effective for the Partnership as of the period ended June 30, 2009, and did not have a material impact on the Partnership's financial statements upon adoption.

In June 2009, the FASB amended the guidance related to Variable Interest Entities ("VIEs"). The amended guidance changes the criteria for determining if a VIE exists and whether or not a VIE should be consolidated. When this guidance is adopted, the Partnership must reconsider its previous VIE conclusions and what types of financial statement disclosures are appropriate. The amended guidance is effective for the Partnership on January 1, 2010, and the Partnership is currently evaluating the impact on its financial statements.

In June 2009, the FASB issued guidance that identifies the FASB Accounting Standards Codification (the "FASB Codification") as the source of authoritative GAAP. All of the FASB Codification's content has the same level of authority. The FASB Codification became effective for the

**3. Recent Accounting Pronouncements (Continued)**

Partnership for the interim period beginning July 1, 2009. The adoption of the FASB Codification did not have a material impact on the Partnership's financial statements.

In September 2009, the FASB amended the accounting guidance for revenue recognition for multiple-deliverable arrangements. The amended guidance establishes a hierarchy for determining the selling price of each individual deliverable and eliminates the residual value method of allocating the selling price. The amended guidance is effective prospectively for all revenue arrangements entered into or materially modified in fiscal years beginning after June 15, 2010. The Partnership is currently evaluating the impact of the amended guidance on its financial statements.

**4. Variable Interest Entities**

*MarkWest Liberty Midstream*

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

The Partnership has determined that MarkWest Liberty Midstream is a variable interest entity primarily due to the insufficiency of equity, as defined in the generally accepted accounting principles for consolidation, at its inception as evidenced by the capital requirements outlined below. The Partnership is considered the primary beneficiary due mainly to its 60% share of profits and losses relative to the equal participation by both members in certain management decisions. The Partnership assumes additional variability based on its compensation as the operator of MarkWest Liberty Midstream. The Partnership's maximum exposure to loss as a result of its involvement with MarkWest Liberty Midstream includes its equity investment, the additional capital contribution commitments and any operating expense in excess of its compensation as the operator of MarkWest Liberty Midstream. MarkWest Liberty Midstream will be funded entirely by the Partnership and M&R and has no debt.

M&R has contributed an additional $100.0 million through the end of the third quarter of 2009 and will contribute at least an additional $50.0 million during the remainder of 2009 to fund the capital expenditures of MarkWest Liberty Midstream. If MarkWest Liberty Midstream capital expenditures during 2009 exceed M&R's quarterly contributions, the Partnership is required to fund the excess. The Partnership contributed approximately $8.0 million to MarkWest Liberty Midstream during the nine months ended September 30, 2009. As M&R contributed the majority of capital associated with 2009 capital expenditures, the capital contributed to MarkWest Liberty Midstream is disproportionate to each party's respective ownership interest. Under the terms of the joint venture agreement, M&R received a special $1.7 million non-cash allocation of net income from MarkWest Liberty Midstream for

**4. Variable Interest Entities (Continued)**

the three and nine months ended September 30, 2009 because its capital contributed exceeded its 40% ownership interest. The Partnership will make additional capital contributions to fund MarkWest Liberty Midstream's capital expenditures between January 1, 2010 and December 31, 2011 in order for the Partnership's share of contributed capital to be proportionate to its ownership interest. MarkWest Liberty Midstream's capital plan for 2010 and 2011 has not been finalized and the exact timing of these contributions is currently uncertain. If the Partnership has not contributed capital in proportion to its ownership interest by the end of 2011, M&R may require the Partnership to contribute the amount of the shortfall at December 31, 2011, or may allow the Partnership to continue to fund 100% of MarkWest Liberty Midstream's capital expenditures until its total contributed capital is proportionate to its 60% ownership interest. After the date at which each party's contributed capital is proportionate to its respective ownership interest, M&R will have the option to fund future capital expenditures in relation to its ownership interest or have its ownership interest diluted to the extent that it elects not to fund its proportionate share.

Effective November 1, 2009, the Partnership and M&R executed the Second Amended and Restated Limited Liability Company Agreement of MarkWest Liberty Midstream ("Amended Liberty Agreement"). Refer to Note 22 for further discussion of the Amended Liberty Agreement.

*MarkWest Pioneer*

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

On May 1, 2009, the Partnership entered into a joint venture with Arkoma Pipeline Partners, LLC ("ArcLight"), an affiliate of ArcLight Capital Partners, LLC which is an investment firm focused on opportunities throughout the energy industry. ArcLight acquired a 50% equity interest in MarkWest Pioneer for a total purchase price of $62.5 million. The Partnership retained a 50% equity interest and is obligated to fund all capital expenditures necessary to complete construction of the Arkoma Connector Pipeline in excess of $125.0 million (the "Excess Capital Expenditures").

The Partnership has determined that MarkWest Pioneer is a variable interest entity under generally accepted accounting principles for consolidation. This determination is based primarily on disproportionate economic interests as compared to voting interests. The Partnership has economic interests that do not match its 50% voting interest due to its obligation to fund the Excess Capital Expenditures.

*Financial Statement Impact of VIEs*

As the primary beneficiary of MarkWest Liberty Midstream and MarkWest Pioneer, the Partnership consolidates the entities and recognizes non-controlling interests. The Partnership has not provided any financial support that it was not contractually obligated to provide.

**4. Variable Interest Entities (Continued)**

The Partnership reflected the following amounts in its Condensed Consolidated Balance Sheet for MarkWest Liberty Midstream and MarkWest Pioneer (in thousands):

| | As of September 30, 2009 | |
|---|---|---|
| | MarkWest Liberty Midstream | MarkWest Pioneer |
| **ASSETS** | | |
| Cash and cash equivalents | $ 7,914 | $ 80 |
| Receivables and other current assets(1) | 20,189 | 1,247 |
| Property, plant and equipment, net of accumulated depreciation of $5,409 and $1,472, respectively | 257,202 | 153,721 |
| Other long-term assets | 10,656 | — |
| Total assets | $295,961 | $155,048 |
| **LIABILITIES** | | |
| Other current liabilities | $ 21,126 | $ 2,298 |
| Other long-term liabilities | 77 | 275 |
| Total liabilities | $ 21,203 | $ 2,573 |

(1) Includes $10.0 million of cash which is restricted for the approved use of MarkWest Liberty Midstream and is not available to the Partnership for any other purpose.

The assets of MarkWest Liberty Midstream and MarkWest Pioneer are the property of the respective ventures and are not available to the Partnership for any other purpose, including collateral for its secured debt (see Note 12 and Note 20). The liabilities of MarkWest Liberty Midstream and MarkWest Pioneer do not represent additional claims against the Partnership's general assets. The Partnership's Liberty segment includes the results of operations of MarkWest Liberty Midstream (see Note 19). The Partnership's Southwest segment includes the results of operations of MarkWest Pioneer (see Note 19). The cash flow information for MarkWest Liberty Midstream and MarkWest Pioneer comprise substantially all of the cash flow information of non-guarantors (see Note 20).

**4. Variable Interest Entities (Continued)**

The following table shows the net income (loss) attributable to the Partnership and transfers to the non-controlling interests for the three and nine months ended September 30, 2009 (in thousands).

| | Three Months Ended September 30, 2009 | Nine Months Ended September 30, 2009 |
|---|---|---|
| Net income (loss) attributable to the Partnership | $ 8,280 | $ (88,875) |
| Transfers to the non-controlling interests: | | |
| Decrease in Partners' Capital for transaction costs related to sale of equity interest in MarkWest Liberty Midstream and MarkWest Pioneer | — | (7,311) |
| Decrease to Partners' Capital for transfer to non-controlling interest from sale of equity interest in MarkWest Pioneer(1) | (9,039) | (14,928) |
| Net loss attributable to the Partnership and transfers to the non-controlling interests | $ (759) | $(111,114) |

(1) Decrease to Partners' Capital for transfer to non-controlling interest is determined based on the total amount of Excess Capital Expenditures funded by the Partnership. As of September 30, 2009, the decrease reflects an estimate shown net of tax benefit, and is subject to further adjustment.

**5. Sale of Steam Methane Reformer**

On September 1, 2009, the Partnership completed the sale of the Steam Methane Reformer ("SMR") currently being constructed 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 will complete the construction of the SMR. The Partnership and the purchaser also executed a related hydrogen supply agreement under which the Partnership will receive all of the hydrogen produced by the SMR for the next 20 years in exchange for processing fees and the reimbursement of certain other expenses. The processing fee payments will begin when the SMR commences operations, which is expected to occur in March 2010. In accordance with generally accepted accounting principles, 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, not an asset sale. The Partnership will continue to report an asset, and the related depreciation, for the capitalized costs of constructing the SMR prior to the transaction closing date and will record the proceeds from the transaction as a liability ("SMR Liability"). The Partnership will impute interest on the SMR Liability at 9.35% annually, its incremental borrowing rate at the time of the transaction. Until the SMR is placed into service and the Partnership begins payment of the processing fee under the hydrogen supply agreement, the accrued interest on the SMR Liability will be capitalized. Each processing fee payment will have multiple elements: reduction of principal of the SMR Liability, interest expense associated with the SMR Liability, and facility expense related to the

**5. Sale of Steam Methane Reformer (Continued)**

operation of the SMR. As of September 30, 2009, the following amounts related to the SMR are included in the accompanying Condensed Consolidated Balance Sheets (in thousands).

| | |
|---|---|
| **ASSETS** | |
| Property, plant and equipment, net of accumulated depreciation of $0 | $82,159 |
| **LIABILITIES** | |
| Other current liabilities | $ 786 |
| Other long-term liabilities | 72,912 |

**6. Derivative Financial Instruments**

*Commodity Contracts*

The Partnership's primary risk management objective is to reduce downside volatility in its cash flows arising from changes in commodity prices related to future sales or purchases of natural gas, NGLs and crude oil. Swaps, options and fixed-price forward contracts may allow the Partnership to reduce downside volatility in its realized margins as realized losses or gains on the derivative instruments generally are offset by corresponding gains or losses in the Partnership's sales or purchases of physical product. While management largely expects realized derivative gains and losses to be offset by increases or decreases in the value of physical sales and purchases, the Partnership will experience volatility in reported earnings due to the recording of unrealized gains and losses on derivative positions that will have no offset. The Partnership's commodity derivative instruments are recorded at fair value in the Condensed Consolidated Balance Sheets and Condensed Consolidated Statements of Operations. Accordingly, the volatility in any given period related to unrealized gains or losses can be significant to the overall financial results of the Partnership; however, management generally expects those gains and losses to be offset when they become realized. The Partnership does not have any trading derivative financial instruments.

To mitigate its cash flow exposure to fluctuations in the price of NGLs, the Partnership has primarily entered into derivative financial instruments relating to the future price of crude oil. 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. As a result of these transactions, the Partnership has mitigated a significant portion of its expected commodity price risk with agreements expiring at various times through the fourth quarter of 2012. The Partnership has a committee comprised of the senior management team that oversees all of the risk management activity and continually monitors the risk management program and expects to continue to adjust its financial positions as conditions warrant.

To manage its commodity price risk, the Partnership utilizes a combination of fixed-price forward contracts, fixed-for-floating price swaps and options available in the OTC market. The Partnership enters into OTC derivatives with financial institutions and other energy company counterparties. Management conducts a standard credit review on counterparties and has agreements containing collateral requirements where deemed necessary. The Partnership uses standardized agreements that allow for offset of positive and negative exposures (master netting arrangements). Due to the timing of

**6. Derivative Financial Instruments (Continued)**

purchases and sales, direct exposure to price volatility may result because there is no longer an offsetting purchase or sale that remains exposed to market pricing. Through marketing and derivative activities, direct price exposure may occur naturally or the Partnership may choose direct exposure when it is favorable as compared to the keep-whole risk.

The use of derivative instruments may create exposure to the risk of financial loss in certain circumstances, including instances when (i) NGLs do not trade at historical levels relative to crude oil, (ii) sales volumes are less than expected, requiring market purchases to meet commitments, or (iii) OTC counterparties fail to purchase or deliver the contracted quantities of natural gas, NGLs or crude oil or otherwise fail to perform. To the extent that the Partnership engages in derivative activities, it may be prevented from realizing the benefits of favorable price changes in the physical market; however, it may be similarly insulated against unfavorable changes in such prices.

The Partnership's Credit Agreement limits its ability to enter into transactions with parties that require margin calls under certain derivative instruments and prevents members of the participating bank group from requiring margin calls. As of September 30, 2009 approximately 6% of the Partnership's derivative positions, measured volumetrically, are with non-bank group counterparties and are subject to margin deposit requirements under OTC agreements that it meets with letters of credit, if necessary. In the unlikely event that the Partnership were unable to meet these margin calls with letters of credit, it would be forced to terminate the corresponding contracts.

*Interest Rate Contracts*

In order to maintain a cost effective capital structure, the Partnership borrows funds using a combination of fixed and variable rate debt. The Partnership uses 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.

*Other Contracts—Embedded Derivatives Related to Long-Term Debt*

On May 26, 2009, the Partnership completed the private placement of senior notes with two contingent written put options as described in Note 12. The written put options are considered embedded derivatives and are not considered clearly and closely related to the indenture. In accordance with generally accepted accounting principles, when a hybrid contract contains more than one embedded derivative requiring separate accounting, the embedded derivatives must be aggregated and accounted for as one compound embedded derivative. The initial fair value of the compound embedded derivative in the indenture (the "Compound Derivative") was recorded as a component of *Long-term debt* in the Condensed Consolidated Balance Sheets with a corresponding increase in the recorded balance of the original issue discount related to the senior notes issued in May 2009.

The Partnership values its derivative instruments and estimates fair value as discussed in Note 7. The Partnership has not designated any of its instruments as cash flow or fair value hedges. The Partnership did not designate any contracts as normal purchase or sales contracts.

**6. Derivative Financial Instruments (Continued)**

The impact of the Partnership's derivative instruments on its Condensed Consolidated Balance Sheets and Condensed Consolidated Statements of Operations are summarized below (in thousands):

| Derivative contracts not designated as hedging instruments and their balance sheet location | Asset Derivatives: Fair Value at September 30, 2009 | Asset Derivatives: Fair Value at December 31, 2008 | Liability Derivatives: Fair Value at September 30, 2009 | Liability Derivatives: Fair Value at December 31, 2008 |
|---|---|---|---|---|
| *Commodity Contracts* | | | | |
| Fair value of derivative instruments—current | $16,397 | $126,949 | $(35,134) | $(37,633) |
| Fair value of derivative instruments—long-term | 29,768 | 55,389 | (33,663) | (14,801) |
| *Interest rate contracts* | | | | |
| Fair value of derivative instruments—current | 1,399 | — | — | — |
| Fair value of derivative instruments—long-term | 866 | — | — | — |
| *Other Contracts* | | | | |
| Long-term debt | — | — | (246) | — |
| Total | $48,430 | $182,338 | $(69,043) | $(52,434) |

| Derivative contracts not designated as hedging instruments and the location of gain or (loss) recognized in income | Three months ended September 30, 2009 | Three months ended September 30, 2008 | Nine months ended September 30, 2009 | Nine months ended September 30, 2008 |
|---|---|---|---|---|
| *Revenue: Derivative gain (loss)* | | | | |
| Realized gain (loss) | $ 9,254 | $(22,197) | $ 85,667 | $(64,961) |
| Unrealized gain (loss) | 504 | 285,008 | (150,840) | (31,069) |
| Total Revenue: derivative gain (loss) | 9,758 | 262,811 | (65,173) | (96,030) |
| *Derivative (loss) gain related to purchased product costs* | | | | |
| Realized (loss) gain | (15,271) | 7,419 | (42,530) | 15,858 |
| Unrealized gain (loss) | 7,455 | (74,993) | 2,576 | (4,338) |
| Total derivative (loss) gain related to purchased product costs | (7,816) | (67,574) | (39,954) | 11,520 |
| *Derivative loss related to facility expenses* | | | | |
| Unrealized loss | (1,347) | (1,748) | (122) | (1,395) |
| *Derivative gain related to interest expense* | | | | |
| Unrealized gain | 2,265 | — | 2,265 | — |
| *Other income, net* | | | | |
| Unrealized gain | 189 | — | 280 | — |
| Total gain (loss) | $ 3,049 | $193,489 | $(102,704) | $(85,905) |

**6. Derivative Financial Instruments (Continued)**

The change in fair value of commodity and interest rate contracts, realized and unrealized, are recorded in separate line items *Derivative gain or loss* related to either revenue, purchased product costs, facility expenses, or interest expense in the accompanying Condensed Consolidated Statements of Operations. Revenue gains and losses relate to contracts utilized to economically hedge the cash flow for the sale of a product. Purchased product costs gains and losses relate to contracts utilized to economically hedge costs, typically in a keep-whole arrangement. Facility expenses gains and losses relate to a contract utilized to economically hedge electricity costs for a facility. Interest expense gains relate to interest rate swaps. The unrealized gain or loss related to changes in the fair value of the Compound Derivative is recorded in *Other income, net* in the accompanying Condensed Consolidated Statements of Operations.

At September 30, 2009, the fair value of the Partnership's commodity derivative contracts is inclusive of premium payments of $9.2 million, net of amortization. The Partnership amortizes the premium payments over the effective term of the underlying derivative commodity option contracts through realized gain (loss). For the three months ended September 30, 2009 and 2008, the Realized gain (loss)—revenue includes amortization of premium payments of $1.5 million and $0.7 million, respectively. For the nine months ended September 30, 2009 and 2008, the Realized gain (loss)—revenue includes amortization of premium payments of $4.2 million and $1.1 million, respectively.

*Credit Risk Contingent Feature*

The Partnership has a contractual arrangement with one non-bank group counterparty that contains a credit risk contingent feature. The Partnership has OTC swap and put positions with this counterparty. This arrangement contains provisions that if the Partnership's credit rating for its long-term senior unsecured debt, as announced by Moody's Investors Service, Inc. and Standard and Poor's Corporation were to decline below B3 or B-, respectively, the Partnership would be required to post additional collateral in the amount of 15% of all outstanding transactions if the contract value of all outstanding transactions was in a net liability position. The Partnership has a standard master netting arrangement with this counterparty. The aggregate fair value of all derivative contracts with a credit risk related contingent feature that are in a liability position at September 30, 2009 is $3.1 million; however, for all outstanding transactions with this counterparty, the Partnership has a net asset position of $6.7 million. If the credit risk contingent feature was triggered as of September 30, 2009, the Partnership would not be required to post additional collateral as collateral is not required when the net position is an asset. If the Partnership's net position became a liability and collateral was required to be posted, it would be accomplished through a letter of credit due to a restriction in the credit agreement which does not allow cash collateral.

## 6. Derivative Financial Instruments (Continued)

*Outstanding Derivative Contracts*

The following tables provide information on the volume of the Partnership's derivative activity for positions related to long liquids and keep-whole price risk and interest rate risk at September 30, 2009, including the weighted average prices ("WAVG"):

| WTI Crude Collars | Volumes (Bbl/d) | WAVG Floor (Per Bbl) | WAVG Cap (Per Bbl) | Fair Value (in thousands) |
|---|---|---|---|---|
| 2009 | 3,425 | $67.50 | $77.83 | $ (5) |
| 2010 (Apr - Dec) | 1,297 | 66.48 | 74.49 | (1,385) |
| 2011 | 822 | 60.00 | 80.13 | (1,675) |
| 2012 | 822 | 60.00 | 85.87 | (1,648) |

| WTI Crude Puts | Volumes (Bbl/d) | WAVG Floor (Per Bbl) | Fair Value (in thousands) |
|---|---|---|---|
| 2009 | 2,150 | $80.00 | $2,026 |
| 2010 | 1,191 | 80.00 | 5,893 |
| 2011 | 1,818 | 80.00 | 9,804 |

| WTI Crude Swaps | Volumes (Bbl/d) | WAVG Price (Per Bbl) | Fair Value (in thousands) |
|---|---|---|---|
| 2009 | 1,585 | $119.54 | $ 6,890 |
| 2010 | 3,513 | 69.21 | (6,025) |
| 2011 | 535 | 68.20 | (1,692) |
| 2012 | 529 | 70.30 | (1,598) |

| Natural Gas Swaps | Volumes (MMBtu/d) | WAVG Price (Per MMBtu) | Fair Value (in thousands) |
|---|---|---|---|
| 2009 | 10,667 | $8.54 | $(3,863) |

| Interest Rate Swaps | Principal Notional Amount (in thousands) | WAVG LIBOR Spread | Fair Value (in thousands) |
|---|---|---|---|
| 2014 (Settlement Dates May 1st & Nov 1st) | $275,000 | 3.83% | $2,265 |

The following tables provide information on the volume of the Partnership's taxable subsidiary's commodity derivative activity for positions related to keep-whole price risk at September 30, 2009, including the WAVG:

| WTI Crude Collars | Volumes (Bbl/d) | WAVG Floor (Per Bbl) | WAVG Cap (Per Bbl) | Fair Value (in thousands) |
|---|---|---|---|---|
| 2012 | 648 | $70.00 | $91.85 | $(31) |

**6. Derivative Financial Instruments (Continued)**

| WTI Crude Swaps | Volumes (Bbl/d) | WAVG Price (Per Bbl) | Fair Value (in thousands) |
|---|---|---|---|
| 2009 | 4,735 | $69.53 | $ (619) |
| 2010 | 2,906 | 71.27 | (2,872) |
| 2011 | 3,150 | 87.27 | 11,024 |
| 2012 (Jan) | 2,142 | 91.50 | 819 |

| Natural Gas Swaps | Volumes (MMBtu/d) | WAVG Price (Per MMBtu) | Fair Value (in thousands) |
|---|---|---|---|
| 2009 | 18,212 | $7.66 | $ (5,175) |
| 2010 | 10,577 | 9.44 | (10,864) |
| 2011 | 15,429 | 8.79 | (9,440) |
| 2012 | 4,225 | 7.08 | 109 |

The Partnership has a commodity contract with a producer in the Appalachia region which creates a floor on the frac spread for gas purchases of 9,000 Dth/d. The primary term of the commodity contract, a component of a broader regional arrangement, expires on December 31, 2009 but the producer has an option to extend certain contracts through the first quarter of 2015. In October 2009, the producer exercised its right to extend the processing agreement and the commodity contract. The fair value of the commodity contract is marked based on an index price through *Derivative loss (gain) related to purchased product costs*. As of September 30, 2009, the estimated fair value of this contract was $(11.6) million.

The Partnership has a commodity contract which gives it an option to fix a component of the utilities cost to an index price on electricity at one of its plant locations. The value of the derivative component of this contract is marked to market through *Derivative gain related to facility expenses*. As of September 30, 2009, the estimated fair value of this contract was $(0.8) million.

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

## 7. Fair Value

The following table presents the Partnership's financial instruments carried at fair value as of September 30, 2009 and December 31, 2008, in accordance with the hierarchy defined in generally accepted accounting principles for fair value measurements (in thousands):

| | Assets | | Liabilities |
|---|---|---|---|
| **As of September 30, 2009** | **Trading Securities** | **Derivatives** | **Derivatives** |
| Quoted prices in active markets for identical assets (Level 1) | $— | $ — | $ — |
| Significant other observable inputs (Level 2) | — | 24,042 | (47,348) |
| Significant unobservable inputs (Level 3) | — | 24,388 | (21,695) |
| Total carrying value in Condensed Consolidated Balance Sheet | $— | $48,430 | $(69,043) |

| | Assets | | Liabilities |
|---|---|---|---|
| **As of December 31, 2008** | **Trading Securities** | **Derivatives** | **Derivatives** |
| Quoted prices in active markets for identical assets (Level 1) | $ — | $ — | $ — |
| Significant other observable inputs (Level 2) | — | 106,826 | (49,378) |
| Significant unobservable inputs (Level 3) | 512 | 75,512 | (3,056) |
| Total carrying value in Condensed Consolidated Balance Sheet | $512 | $182,338 | $(52,434) |

*Changes in Level 3 Fair Value Measurements*

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 transactions and the Compound Derivative as they have significant unobservable market parameters. Depending on the Level 3 financial instrument significant unobservable inputs include volatilities associated with option contracts, commodity prices interpolated and extrapolated due to inactive markets, and for the Compound Derivative assumptions about the probability of specific events occurring in the future.

The tables below include a rollforward of the balance sheet amounts for the three and nine months ended September 30, 2009 and 2008 (including the change in fair value) for financial instruments classified by the Partnership within Level 3 of the valuation hierarchy (in thousands). For the period ended September 30, 2008 the Partnership considered options to be Level 2. After further

**7. Fair Value (Continued)**

consideration, options are considered Level 3 due to significant unobservable inputs. Therefore, the rollforwards presented below for the three and nine months ended September 30, 2009 include options.

| | Three Months Ended | | | |
|---|---|---|---|---|
| | September 30, 2009 | | September 30, 2008 | |
| | Trading Securities | Derivatives (net) | Trading Securities | Derivatives (net) |
| Fair Value at Beginning of Period | $— | $10,034 | $1,198 | $(187,353) |
| Total gain or loss (realized and unrealized) included in earnings(a)(b) | — | (3,913) | — | 105,864 |
| Purchases, sales, issuances and settlements (net) | — | (3,428) | — | 17,543 |
| Transfers in or out of Level 3 (net) | — | — | — | — |
| Fair Value at End of Period | $— | $ 2,693 | $1,198 | $ (63,946) |
| The amount of total gains or losses for the period included in earnings (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets still held at September 30, 2009 and 2008, respectively(a) | $— | $ (5,237) | $ — | $ 109,455 |

| | Nine Months Ended | | | |
|---|---|---|---|---|
| | September 30, 2009 | | September 30, 2008 | |
| | Trading Securities | Derivatives (net) | Trading Securities | Derivatives (net) |
| Fair Value at Beginning of Period | $ 512 | $ 72,456 | $ 3,674 | $(84,367) |
| Total gain or loss (realized and unrealized) included in earnings(a)(b) | 40 | (36,915) | (76) | (46,219) |
| Purchases, sales, issuances and settlements (net) | (552) | (32,848) | (2,400) | 66,640 |
| Transfers in or out of Level 3 (net) | — | — | — | — |
| Fair Value at End of Period | $ — | $ 2,693 | $ 1,198 | $(63,946) |
| The amount of total gains or losses for the period included in earnings (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets still held at September 30, 2009 and 2008, respectively(a) | $ — | $(42,471) | $ (76) | $ (4,367) |

(a) See Note 6 for the financial statement presentation of gains and losses on derivatives.

(b) Gains and losses on trading securities are realized and recorded in *Other income, net*.

**7. Fair Value (Continued)**

*Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis*

Certain assets and liabilities are measured at fair value on a nonrecurring basis; that is, the instruments are not measured at fair value on an ongoing basis but are subject to fair value adjustments in certain circumstances. As of June 30, 2009, certain long-lived assets of Wirth Gathering Partnership ("Wirth"), a consolidated subsidiary, were required to be measured at fair value in conjunction with the Partnership's impairment evaluation for long-lived assets. Property, plant and equipment and intangible assets with a net book value of $5.2 million and $0.7 million, respectively, were written down to an estimated fair value of zero, resulting in an impairment charge of $5.9 million. The Partnership estimated the fair value of these assets based on an income approach using significant unobservable inputs (Level 3). See Note 10 for further discussion of the impairment. As of September 30, 2009, there were no assets or liabilities to be measured at fair value on a nonrecurring basis.

**8. Inventories**

Inventories are included in *Receivables and other current assets* in the Condensed Consolidated Balance Sheet. Inventories consist of the following (in thousands):

| | September 30, 2009 | December 31, 2008 |
|---|---|---|
| Natural gas and natural gas liquids | $22,660 | $29,171 |
| Spare parts | 7,766 | 2,385 |
| Total inventories | $30,426 | $31,556 |

**9. Goodwill**

The Partnership's $9.4 million goodwill balance as of September 30, 2009 and December 31, 2008 consisted of $3.9 million allocated to the Northeast segment and $5.5 million allocated to the Southwest segment. The goodwill balance is included in *Other long-term assets* in the Condensed Consolidated Balance Sheet. Goodwill is not amortized but instead tested for impairment annually on November 30, or more frequently when events and circumstances occur indicating that the recorded goodwill may not be recoverable. As of September 30, 2009, the Partnership did not test goodwill for impairment as there were no indicators that the goodwill balance may not be recoverable.

**10. 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.

## 10. Impairment of Long-Lived Assets (Continued)

An analysis completed during the second quarter of 2009 indicated that the future estimated operating cash flows could be at or below zero for Wirth, which operates a small natural gas gathering system included in the Partnership's Southwest segment. The Partnership owns a 50% interest in Wirth and consolidates its assets, liabilities, and results of operations in the accompanying Condensed Consolidated Financial Statements. Wirth'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 the nine months ended September 30, 2009. After considering the impact of the non-controlling interest, the impairment increased the net loss attributable to the Partnership for the nine months ended September 30, 2009 by approximately $2.9 million, before provision for income tax.

## 11. Investments in Unconsolidated Affiliates

The Partnership's investment in its unconsolidated affiliates, Starfish Pipeline Company, L.L.C. ("Starfish") and Centrahoma Processing L.L.C. ("Centrahoma"), is included in *Other long-term assets* in the accompanying Condensed Consolidated Balance Sheet. The Partnership's share of income from its investments in unconsolidated affiliates is included in *Earnings (loss) from unconsolidated affiliates* in the accompanying Condensed Consolidated Statements of Operations.

Summarized financial information for 100% of Starfish and the Partnership's share of Starfish's net income (loss) is as follows (unaudited, in thousands):

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2009 | 2008 | 2009 | 2008 |
| Revenue | $8,566 | $5,247 | $22,636 | $19,624 |
| Operating income (loss) | 4,102 | (399) | 12,389 | 3,800 |
| Net income (loss) | 806 | (355) | 3,780 | 4,188 |
| Partnership's share of net income (loss) | $ 403 | $ (248) | $ 1,848 | $ 1,878 |

In addition, the Partnership settled certain insurance claims related to damage and business interruption caused by Hurricane Ike in 2008. Total insurance proceeds of $0.7 million are included in *Other income, net* in the Condensed Consolidated Statements of Operations.

## 11. Investments in Unconsolidated Affiliates (Continued)

Summarized financial information for 100% of Centrahoma and the Partnership's share of Centrahoma's net income (loss) is as follows (unaudited, in thousands):

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2009 | 2008 | 2009 | 2008 |
| Revenue | $2,369 | $2,410 | $ 6,568 | $4,455 |
| Operating income | 556 | 138 | 2,324 | 134 |
| Net (loss) income | (585) | 138 | (1,471) | 134 |
| Partnership's share of net (loss) income | $ (234) | $ 52 | $ (588) | $ 54 |

The table below shows the carrying value of the Partnership's investments in unconsolidated affiliates (in thousands):

| | September 30, 2009 | December 31, 2008 |
|---|---|---|
| Investment in Starfish | $24,291 | $17,181 |
| Investment in Centrahoma | 29,496 | 28,911 |
| Total investment in unconsolidated affiliates | $53,787 | $46,092 |

## 12. Long-Term Debt

Long-term debt is summarized below (in thousands):

| | September 30, 2009 | December 31, 2008 |
|---|---|---|
| **Credit Facility** | | |
| Revolver facility, 5.0% and 2.51% interest at September 30, 2009 and December 31, 2008, respectively, due February 2012 | $ 51,800 | $ 184,700 |
| **Senior Notes** (collectively the "Senior Notes") | | |
| Senior Notes, 6.875% interest, net of discount of $8,501 and $9,676, respectively, issued October 2004 and due November 2014 | 216,499 | 215,324 |
| Senior Notes, 6.875% interest, net of discount of $31,172 and $0, respectively, issued May 2009 and due November 2014(1) | 119,074 | — |
| Senior Notes, 8.5% interest, net of discount of $792 and $882, respectively, issued July 2006 and due July 2016 | 274,208 | 274,118 |
| Senior Notes, 8.75% interest, net of discount of $1,083 and $1,177, respectively, issued April 2008 and due April 2018 | 498,917 | 498,823 |
| Total long-term debt | $1,160,498 | $1,172,965 |

(1) Includes fair value of approximately $0.2 million of written put options as discussed below.

**12. Long-Term Debt (Continued)**

*Credit Facility*

On January 28, 2009, the Partnership entered into the first amendment to its Partnership Credit Agreement which became effective March 2, 2009. The amendment expands the Partnership's borrowing capacity under the revolving facility by $85.6 million from $350.0 million to $435.6 million. Pursuant to the amendment, the term of the original credit agreement has been reduced by one year and is now due on February 20, 2012. The accordion feature established under the original credit agreement was reset to $200.0 million of uncommitted funds. The borrowings under the revolving credit facility of the Partnership Credit Agreement continue to bear interest at a variable interest rate, plus basis points. The variable interest rate typically is based on LIBOR; however, in certain borrowing circumstances the rate would be based on the higher of a) the Federal Funds Rate plus 0.5%, and b) a rate set by the Partnership Credit Agreement's administrative agent, based on the U.S. prime rate. The basis points correspond to the ratio of the Partnership's Consolidated Funded Debt (as defined in the Partnership Credit Agreement) to Adjusted Consolidated EBITDA (as defined in the Partnership Credit Agreement). Under the original agreement, the basis points ranged from 50 to 125 for Base Rate loans, and 150 to 225 for LIBOR loans. Under the terms of the amendment, the basis points range from 150 to 225 for Base Rate loans and 250 to 325 for LIBOR loans. The amendment also established a floor of 2% for the LIBOR rate used to determine the interest rate on the LIBOR loans. The Partnership incurred and capitalized approximately $4.3 million of debt modification fees and other professional services as a result of the amendment. The amendment also resulted in the write-off of approximately $0.3 million of previously capitalized deferred finance costs during the first quarter of 2009, which is included in *Amortization of deferred financing costs and discount* in the accompanying Condensed Consolidated Statements of Operations.

Under the provisions of the Partnership Credit Agreement, the Partnership is subject to a number of restrictions and covenants as defined by the agreement. These covenants are used to calculate the available borrowing capacity on a quarterly basis. The credit facility is guaranteed and collateralized by substantially all of the Partnership's assets and those of its wholly-owned subsidiaries. As of September 30, 2009, the Partnership had $51.8 million of borrowings outstanding and $31.5 million of letters of credit outstanding under the revolving credit facility, leaving approximately $352.3 million available for borrowing.

The recorded value of the amounts outstanding under the revolving credit facility as of September 30, 2009 approximates fair value due to the short-term nature of the borrowings and the variable interest rate that reflects current market conditions.

*Senior Notes*

As of September 30, 2009, MarkWest Energy Partners, L.P. in conjunction with its wholly-owned subsidiary MarkWest Energy Finance Corporation (the "Issuers") had four series of Senior Notes outstanding. On May 26, 2009, the Issuers completed a private placement of $150.0 million in aggregate principal amount of 6.875% senior unsecured notes due 2014 to qualified institutional buyers under Rule 144A. The Partnership received proceeds of approximately $113.8 million, after deducting the initial purchasers' discounts and other expenses of the private placement. The proceeds were primarily used to repay borrowings under the Partnership's revolving credit facility. Interest on these senior notes is payable on each May 1 and November 1 and will accrue from May 26, 2009.

**12. Long-Term Debt (Continued)**

On July 2, 2009, the Partnership filed an exchange offer registration statement, pursuant to the registration rights agreement for the senior notes issued in May 2009. The exchange offering was initiated in the fourth quarter of 2009 and is currently in process.

The indenture for the senior notes issued in May 2009 contains the following two contingent written put options exercisable by the debt holders (see Note 6 for more information on the separate accounting for the written put options and Note 7 for more information on the determination of the fair value):

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

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

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

The estimated fair value of all outstanding Senior Notes was approximately $1,121.5 million and $627.1 million at September 30, 2009 and December 31, 2008, respectively, based on quoted market prices.

The Issuers have no independent operating assets or operations. All wholly-owned subsidiaries, other than MarkWest Energy Finance Corporation, guarantee the Senior Notes, jointly and severally and fully and unconditionally. The Partnership's less than wholly-owned subsidiaries do not guarantee the Senior Notes (see Note 20 for required condensed consolidating financial information). The notes are senior unsecured obligations equal in right of payment with all of the Partnership's existing and future senior debt. These notes are senior in right of payment to all of the Partnership's future subordinated debt but effectively junior in right of payment to its secured debt to the extent of the assets securing the debt, including the Partnership's obligations in respect of the Partnership Credit Agreement.

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

## 13. Income Taxes

A reconciliation of the provision for income tax and the amount computed by applying the federal statutory rate of 35% to the income (loss) before provision for income tax for the nine months ended September 30, 2009 and 2008 is as follows (in thousands):

| | Nine months ended September 30, 2009 | | | |
|---|---|---|---|---|
| | Corporation | Partnership | Eliminations | Consolidated |
| Loss before provision for income tax | $(72,819) | $(32,505) | $(9,800) | $(115,124) |
| Federal statutory rate | 35% | 0% | 0% | |
| Federal income tax at statutory rate | $(25,486) | $ — | $ — | $ (25,486) |
| Permanent items | (6) | — | — | (6) |
| State income taxes net of federal benefit | (1,794) | (216) | — | (2,010) |
| Provision on income from Class A units | (1,072) | — | — | (1,072) |
| Excess book deduction related to equity compensation | 408 | 3 | — | 411 |
| Provision for income tax | $(27,950) | $ (213) | $ — | $ (28,163) |
| Effective tax rate | | | | 24.5% |

| | Nine months ended September 30, 2008 | | | |
|---|---|---|---|---|
| | Corporation | Partnership | Eliminations | Consolidated |
| Income before provision for income tax | $ 1,876 | $48,020 | $(8,775) | $41,121 |
| Federal statutory rate | 35% | 0% | 0% | |
| Federal income tax at statutory rate | $ 657 | $ — | $ — | $ 657 |
| Permanent items | 8 | — | — | 8 |
| State income taxes net of federal benefit | 47 | 302 | — | 349 |
| Provision on income from Class A units | 8,188 | — | — | 8,188 |
| Write-off of deferred income tax assets | 7,471 | — | — | 7,471 |
| Other | (211) | — | — | (211) |
| Provision for income tax | $16,160 | $ 302 | $ — | $16,462 |
| Effective tax rate | | | | 40.0% |

## 14. Incentive Compensation Plans

*Compensation Expense*

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

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2009 | 2008 | 2009 | 2008 |
| Phantom units | $1,583 | $3,087 | $5,755 | $ 9,261 |
| Distribution equivalent rights | 328 | 230 | 996 | 468 |
| Restricted stock | — | — | — | 75 |
| General partner interests under Participation Plan | — | — | — | 5,470 |
| Total compensation expense | $1,911 | $3,317 | $6,751 | $15,274 |

The interests in the Partnership's General Partner sold by the Corporation to certain directors and employees were sold under an arrangement referred to as the Participation Plan which was considered a compensatory arrangement. In conjunction with the Merger, all of the outstanding interests in the General Partner were acquired for a combination of 0.9 million common units with a fair value of approximately $30.1 million and approximately $21.5 million in cash.

As of September 30, 2009, total compensation expense not yet recognized related to the unvested awards under the 2008 LTIP and 2006 Hydrocarbon Plan was approximately $16.2 million, with a weighted average remaining vesting period of approximately 1.3 years. Total compensation expense not yet recognized related to unvested awards under the 2002 LTIP was approximately $0.5 million, with a weighted-average remaining vesting period of approximately 0.7 years. The actual compensation expense recognized for awards under the 2002 LTIP may differ as they qualify as liability awards. The compensation expense recognized for liability awards is affected by changes in the fair value of the awards.

*2008 LTIP, 2006 Hydrocarbon Plan and 1996 Hydrocarbon Plan*

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

| | Number of Units | Weighted-average Grant-date Fair Value |
|---|---|---|
| Unvested at December 31, 2008 | 909,306 | $31.80 |
| Granted(1) | 437,535 | 8.47 |
| Vested(2) | (296,818) | 31.93 |
| Forfeited(3) | (30,233) | 20.45 |
| Unvested at September 30, 2009(4) | 1,019,790 | 22.08 |

(1) Includes 154,500 phantom units granted to senior executives and other key employees which contain performance vesting criteria ("performance units").

(2) Includes 139,050 performance units.

(3) Includes 13,950 performance units.

(4) Includes 465,000 performance units. Compensation expense recorded for the performance units expected to vest was approximately $0.3 million and $2.9 million for the nine months ended September 30, 2009 and 2008, respectively.

## 14. Incentive Compensation Plans (Continued)

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2009 | 2008 | 2009 | 2008 |
| | (in thousands) | | | |
| Total grant-date fair value of phantom units granted during the period | $ 47 | $198 | $3,705 | $29,351 |
| Total fair value of phantom units vested during the period and total intrinsic value of phantom units settled during the period | $414 | $424 | $9,478 | $ 549 |

*2002 LTIP*

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

| | Number of Units | Weighted-average Grant-date Fair Value |
|---|---|---|
| Unvested at December 31, 2008 | 145,927 | $31.45 |
| Vested | (67,818) | 29.86 |
| Forfeited | (5,482) | 33.56 |
| Unvested at September 30, 2009 | 72,627 | 32.78 |

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2009 | 2008 | 2009 | 2008 |
| | (in thousands) | | | |
| Total grant-date fair value of phantom units granted during the period | $— | $— | $ — | $2,670 |
| Total fair value of phantom units vested during the period and total intrinsic value of phantom units settled during the period | $49 | $72 | $867 | $1,943 |

## 15. Equity Offerings

On August 18, 2009, the Partnership completed a public offering of approximately 6.03 million newly issued common units, which included the exercise of the overallotment option by the underwriters, representing limited partner interests at a purchase price of $20.95 per common unit. Net proceeds of approximately $121.0 million were used to partially fund the Partnership's 2009 capital expenditure requirements, and the remainder was used to pay down borrowings under its revolving credit facility of the Partnership Credit Agreement.

**15. Equity Offerings (Continued)**

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

**16. Earnings Per Unit**

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

The following table shows the computation of basic and diluted net income (loss) attributable to the Partnership per common unit, for the three and nine months ended September 30, 2009 and 2008,

### 16. Earnings Per Unit (Continued)

and the weighted-average units used to compute diluted net income (loss) attributable to the Partnership per common unit (in thousands, except per unit data):

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2009 | 2008 | 2009 | 2008 |
| Net income (loss) attributable to the Partnership | $ 8,280 | $186,546 | $(88,875) | $27,930 |
| Less: Income allocable to phantom units | 374 | 3,174 | 1,146 | 918 |
| Income (loss) available for common unitholders | $ 7,906 | $183,372 | $(90,021) | $27,012 |
| Weighted average common units outstanding—basic | 63,026 | 56,635 | 59,168 | 49,123 |
| Effect of dilutive instruments | — | — | — | 4 |
| Weighted average common units outstanding—diluted | 63,026 | 56,635 | 59,168 | 49,127 |
| Net income (loss) attributable to the Partnership's common unitholders | | | | |
| Basic | $ 0.13 | $ 3.24 | $ (1.52) | $ 0.55 |
| Diluted | $ 0.13 | $ 3.24 | $ (1.52) | $ 0.55 |

### 17. Distributions to Unitholders

| Quarter Ended | Distribution Per Common Unit | Declaration Date | Ex-dividend Date | Record Date | Payment Date |
|---|---|---|---|---|---|
| September 30, 2009 | $0.64 | October 22, 2009 | October 29, 2009 | November 2, 2009 | November 13, 2009 |
| June 30, 2009 | $0.64 | July 23, 2009 | July 30, 2009 | August 3, 2009 | August 14, 2009 |
| March 31, 2009 | $0.64 | April 23, 2009 | April 30, 2009 | May 4, 2009 | May 15, 2009 |
| December 31, 2008 | $0.64 | January 27, 2009 | February 4, 2009 | February 6, 2009 | February 13, 2009 |

### 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 condensed consolidated financial statements.

**18. Commitments and Contingencies (Continued)**

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. 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 Production Company and leased and operated by a subsidiary, MarkWest Energy Appalachia, L.L.C. The NOPV sets forth six counts of violations of applicable regulations, and a proposed civil penalty in the aggregate amount of $1.1 million. An administrative hearing on the matter, previously set for the last week of March 2007, was postponed to allow the administrative record to be produced and to allow OPS an opportunity to respond to MarkWest's and Equitable's motions to dismiss count one of the NOPV, which involves $0.8 million of the $1.1 million proposed penalty. This count arises out of alleged activity in 1982 and 1987, which predates MarkWest's leasing and operation of the pipeline. The administrative hearing request was withdrawn by MarkWest and Equitable in October 2009, and the case will proceed to initial resolution on the briefs, exhibits and other documents filed or submitted by the parties in the matter. MarkWest believes it has viable and mitigating defenses to the remaining counts and will vigorously defend all applicable assertions of violations at the hearing.

MarkWest Javelina Company, L.L.C. is a party to an action styled *Esmerejilda G. Valasquez, et al. v. Occidental Chemical Corp., et al.,* Case No. A-060352-C, 128th Judicial District, Orange County, Texas, original petition filed July 10, 2006; as refiled from previously dismissed petition captioned *Jesus Villarreal v. Koch Refining Co. et al*., Cause No. 05-01977-F, 214th Judicial Dist. Ct., County of Nueces, Texas, originally filed April 27, 2005), which sets forth claims for wrongful death, personal injury or property damage, and nuisance type claims, allegedly incurred as a result of operations and emissions from MarkWest Javelina's gas processing plant and from various petroleum, petrochemical and metal processing and refining operations located in the area, which were also named as defendants in the action. The action has been and is being vigorously defended, and based on initial evaluation and consultations, it appears at this time that this action should not have a material adverse impact on the Partnership's financial position or results of operations.

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

*SMR Transaction*

On September 1, 2009, the Partnership entered into a hydrogen supply agreement creating a long-term contractual obligation for the payment of processing fees in exchange for all of the hydrogen processed by the SMR (see Note 5 for further discussion of this agreement and the related SMR transaction). The hydrogen received under this agreement will be sold to a refinery customer pursuant to a corresponding long-term agreement. The minimum amounts payable annually under the hydrogen

## 18. Commitments and Contingencies (Continued)

supply agreement, excluding the potential impact of inflation adjustments per the agreement, are as follows (in thousands):

| Year ending December 31, | |
|---|---|
| 2009 | $ — |
| 2010 | 14,510 |
| 2011 | 17,412 |
| 2012 | 17,412 |
| 2013 | 17,412 |
| 2014 and thereafter | 281,494 |
| | $348,240 |

## 19. 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 geographic basis. The Partnership has four segments: Southwest, Northeast, Gulf Coast and Liberty. The Southwest segment provides gathering, processing, transportation, and storage services. The Northeast segment provides gathering, processing, transportation, fractionation and storage services. The Gulf Coast segment provides processing, transportation, fractionation and storage services. The Liberty segment provides gathering, processing, and transportation services. The Liberty segment is a new segment beginning in 2009 and consists primarily of the operations in the Marcellus Shale region of western Pennsylvania and northern West Virginia. For the year ended December 31, 2008, the results of operations in the Liberty segment were included in the Northeast segment because all of the aggregation criteria under the generally accepted accounting principles for segment reporting were satisfied and the results of the Liberty segment were immaterial. However, because the Liberty operations may grow to become a larger portion of the Partnership's business, management believes that transparency to the Liberty segment will provide useful information to investors.

The Partnership prepares segment information in accordance with generally accepted accounting principles. Certain items below *Income (loss) from operations* in the accompanying Condensed 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 segments. Management does not consider these items allocable to or controllable by any individual segment and therefore excludes these items when evaluating segment performance. The segment results are also adjusted to exclude the portion of operating income attributable to the non-controlling interests.

**19. Segment Information (Continued)**

The tables below present information about operating income for the three and nine months ended September 30, 2009 and 2008 and capital expenditures for the reported segments for the nine months ended September 30, 2009 and 2008 (in thousands).

***Three months ended September 30, 2009 and 2008***

| | Southwest | Northeast | Liberty | Gulf Coast | Total |
|---|---|---|---|---|---|
| **Three months ended September 30, 2009:** | | | | | |
| Revenue | $123,792 | $55,554 | $12,790 | $15,797 | $207,933 |
| Operating expenses: | | | | | |
| Purchased product costs | 53,425 | 34,506 | 3,155 | — | 91,086 |
| Facility expenses | 17,893 | 4,832 | 3,435 | 3,869 | 30,029 |
| Total operating expenses before items not allocated to segments | 71,318 | 39,338 | 6,590 | 3,869 | 121,115 |
| Portion of operating income attributable to non-controlling interests | 980 | — | 2,470 | — | 3,450 |
| Operating income before items not allocated to segments | $ 51,494 | $16,216 | $ 3,730 | $11,928 | $ 83,368 |

| | Southwest | Northeast | Liberty(1) | Gulf Coast | Total |
|---|---|---|---|---|---|
| **Three months ended September 30, 2008:** | | | | | |
| Revenue | $192,675 | $82,418 | $— | $28,467 | $303,560 |
| Operating expenses: | | | | | |
| Purchased product costs | 120,208 | 51,331 | — | — | 171,539 |
| Facility expenses | 16,670 | 6,172 | — | 5,085 | 27,927 |
| Operating income before items not allocated to segments | $ 55,797 | $24,915 | $— | $23,382 | $104,094 |

(1) The Partnership began construction in the Liberty segment in May 2008 and operations commenced in October 2008.

**19. 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 months ended September 30, 2009 and 2008 (in thousands).

| | Three months ended September 30, | |
|---|---|---|
| | 2009 | 2008 |
| Total segment revenue | $207,933 | $303,560 |
| Derivative gain not allocated to segments | 9,758 | 262,811 |
| Total revenue | $217,691 | $566,371 |
| Operating income before items not allocated to segments | $ 83,368 | $104,094 |
| Portion of operating income attributable to non-controlling interests | 3,450 | — |
| Derivative gain not allocated to segments | 595 | 193,489 |
| Compensation expense included in facility expenses not allocated to segments | (243) | (286) |
| Facility expenses elimination | 107 | — |
| Selling, general and administrative expenses | (15,477) | (15,331) |
| Depreciation | (25,264) | (17,510) |
| Amortization of intangible assets | (10,193) | (10,732) |
| Other operating expenses | (689) | (38) |
| Income from operations | 35,654 | 253,686 |
| Earnings (loss) from unconsolidated affiliates | 169 | (196) |
| Interest expense | (23,440) | (18,928) |
| Amortization of deferred financing costs and discount (a component of interest expense) | (3,091) | (1,080) |
| Derivative gain related to interest expense | 2,265 | — |
| Other income, net | 925 | 1,322 |
| Income before provision for income tax | $ 12,482 | $234,804 |

**19. Segment Information (Continued)**

***Nine months ended September 30, 2009 and 2008***

| | Southwest | Northeast | Liberty | Gulf Coast | Total |
|---|---|---|---|---|---|
| **Nine months ended September 30, 2009:** | | | | | |
| Revenue | $339,967 | $165,765 | $ 29,510 | $41,058 | $576,300 |
| Operating expenses: | | | | | |
| Purchased product costs | 150,456 | 117,540 | 6,056 | — | 274,052 |
| Facility expenses | 55,703 | 14,796 | 10,557 | 12,303 | 93,359 |
| Total operating expenses before items not allocated to segments | 206,159 | 132,336 | 16,613 | 12,303 | 367,411 |
| Portion of operating income attributable to non-controlling interests | 1,007 | — | 4,113 | — | 5,120 |
| Operating income before items not allocated to segments | $132,801 | $ 33,429 | $ 8,784 | $28,755 | $203,769 |
| Capital expenditures | $197,977 | $ 20,447 | $131,315 | $36,227 | $385,966 |
| Capital expenditures not allocated to segments | | | | | 2,536 |
| Total capital expenditures | | | | | $388,502 |

| | Southwest | Northeast | Liberty(1) | Gulf Coast | Total |
|---|---|---|---|---|---|
| **Nine months ended September 30, 2008:** | | | | | |
| Revenue | $536,563 | $251,115 | $ — | $79,082 | $866,760 |
| Operating expenses: | | | | | |
| Purchased product costs | 322,370 | 157,377 | — | — | 479,747 |
| Facility expenses | 45,189 | 16,161 | — | 13,341 | 74,691 |
| Operating income before items not allocated to segments | $169,004 | $ 77,577 | $ — | $65,741 | $312,322 |
| Capital expenditures | $217,574 | $ 30,157 | $13,880 | $51,388 | $312,999 |
| Capital expenditures not allocated to segments | | | | | 3,882 |
| Total capital expenditures | | | | | $316,881 |

(1) The Partnership began construction in the Liberty segment in May 2008 and operations commenced in October 2008.

**19. Segment Information (Continued)**

The following is a reconciliation of segment revenue to total revenue and operating income before items not allocated to segments to (loss) income before provision for income tax for the nine months ended September 30, 2009 and 2008 (in thousands).

| | Nine months ended September 30, | |
|---|---|---|
| | 2009 | 2008 |
| Total segment revenue | $ 576,300 | $866,760 |
| Derivative loss not allocated to segments | (65,173) | (96,030) |
| Total revenue | $ 511,127 | $770,730 |
| Operating income before items not allocated to segments | $ 203,769 | $312,322 |
| Portion of operating income attributable to non-controlling interests | 5,120 | — |
| Derivative loss not allocated to segments | (105,249) | (85,905) |
| Compensation expense included in facility expenses not allocated to segments | (801) | (950) |
| Facility expenses elimination | 215 | — |
| Selling, general and administrative expenses | (46,265) | (54,406) |
| Depreciation | (69,621) | (48,533) |
| Amortization of intangible assets | (30,638) | (28,050) |
| Other operating expenses | (1,579) | (106) |
| Impairment of long-lived assets | (5,855) | (5,009) |
| (Loss) income from operations | (50,904) | 89,363 |
| Earnings from unconsolidated affiliates | 1,260 | 1,932 |
| Interest expense | (63,964) | (47,527) |
| Amortization of deferred financing costs and discount (a component of interest expense) | (6,528) | (7,287) |
| Derivative gain related to interest expense | 2,265 | — |
| Other income, net | 2,747 | 4,640 |
| (Loss) income before provision for income tax | $(115,124) | $ 41,121 |

**19. Segment Information (Continued)**

The tables below present information about segment assets as of September 30, 2009 and December 31, 2008 (in thousands):

| | Southwest | Northeast | Liberty | Gulf Coast | Total |
|---|---|---|---|---|---|
| **As of September 30, 2009:** | | | | | |
| Total segment assets | $1,598,975 | $230,294 | $295,962 | $571,153 | $2,696,384 |
| Assets not allocated to segments: | | | | | |
| Certain cash and cash equivalents | | | | | 54,015 |
| Fair value of derivative instruments | | | | | 48,430 |
| Investment in unconsolidated affiliates(1) | | | | | 53,787 |
| Other(2) | | | | | 43,647 |
| Total assets | | | | | $2,896,263 |

(1) Included in *Other long-term assets* in the Condensed Consolidated Balance Sheets.

(2) Includes corporate fixed assets, deferred financing costs, income tax receivable, and other corporate assets not allocated to segments.

| | Southwest | Northeast | Liberty | Gulf Coast | Total |
|---|---|---|---|---|---|
| **As of December 31, 2008:** | | | | | |
| Total segment assets | $1,487,205 | $233,403 | $127,785 | $548,503 | $2,396,896 |
| Assets not allocated to segments: | | | | | |
| Certain cash and cash equivalents | | | | | 137 |
| Fair value of derivative instruments | | | | | 182,338 |
| Investment in unconsolidated affiliates(1) | | | | | 46,092 |
| Other(2) | | | | | 47,591 |
| Total assets | | | | | $2,673,054 |

(1) Included in *Other long-term assets* in the Condensed Consolidated Balance Sheets.

(2) Includes corporate fixed assets, deferred financing costs, income tax receivable and other corporate assets not allocated to segments.

## 20. Supplemental Condensed Consolidating Financial Information

MarkWest Energy Partners has no significant operations independent of its subsidiaries. As of September 30, 2009, the Partnership's obligations under the outstanding Senior Notes (see Note 12) were fully and unconditionally guaranteed, jointly and severally, by all of its wholly-owned subsidiaries. Separate financial statements for each of the Partnership's guarantor subsidiaries are not provided because such information would not be material to its investors or lenders. As of February 2009, following the closing of the joint venture with M&R, and May 2009, following the closing of the joint venture with ArcLight (see Note 4), MarkWest Liberty Midstream and MarkWest Pioneer together with certain of the Partnership's other subsidiaries that do not guarantee the outstanding Senior Notes have significant assets and operations in aggregate. For the purpose of the following financial information, the Partnership's investments in its subsidiaries and the guarantor subsidiaries' investments in their subsidiaries are presented in accordance with the equity method of accounting. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had the subsidiaries operated as independent entities. The operations, cash flows, and financial position of the Co-Issuer, MarkWest Energy Finance Corporation, are not material and therefore have been included with the Parent's financial information. Comparative financial statements have not been provided because the non-guarantor subsidiaries as of December 31, 2008 were minor subsidiaries individually and in the aggregate. Condensed consolidating financial information for MarkWest Energy

## 20. Supplemental Condensed Consolidating Financial Information (Continued)

Partners and its combined guarantor and combined non-guarantor subsidiaries as of September 30, 2009 and for the three and nine months ended September 30, 2009 is as follows (in thousands):

### Condensed Consolidating Balance Sheet

| | As of September 30, 2009 | | | | |
|---|---|---|---|---|---|
| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| **ASSETS** | | | | | |
| Current assets: | | | | | |
| Cash and cash equivalents | $ — | $ 54,745 | $ 10,561 | $ — | $ 65,306 |
| Receivables and other current assets | 1,708 | 139,707 | 21,788 | — | 163,203 |
| Intercompany receivables | 1,612,499 | 301,424 | — | (1,913,923) | — |
| Fair value of derivative instruments | 281 | 17,515 | — | — | 17,796 |
| Total current assets | 1,614,488 | 513,391 | 32,349 | (1,913,923) | 246,305 |
| Total property, plant and equipment, net | 3,054 | 1,444,480 | 412,136 | (4,514) | 1,855,156 |
| Other long-term assets: | | | | | |
| Investment in consolidated affiliates | 512,508 | 195,349 | — | (707,857) | — |
| Intangibles, net of accumulated amortization | — | 663,982 | 623 | — | 664,605 |
| Fair value of derivative instruments | 311 | 30,323 | — | — | 30,634 |
| Intercompany notes receivable | 223,610 | — | — | (223,610) | — |
| Other long-term assets | 21,457 | 67,449 | 10,657 | — | 99,563 |
| Total other long-term assets | 757,886 | 957,103 | 11,280 | (931,467) | 794,802 |
| Total assets | $2,375,428 | $2,914,974 | $455,765 | $(2,849,904) | $2,896,263 |
| **LIABILITIES AND PARTNERS' CAPITAL** | | | | | |
| Current liabilities: | | | | | |
| Intercompany payables | $ — | $1,911,498 | $ 2,425 | $(1,913,923) | $ — |
| Fair value of derivative instruments | — | 35,134 | — | — | 35,134 |
| Other current liabilities | 41,074 | 110,784 | 23,664 | — | 175,522 |
| Total current liabilities | 41,074 | 2,057,416 | 26,089 | (1,913,923) | 210,656 |
| Deferred income taxes | 3,489 | 8,134 | — | — | 11,623 |
| Intercompany notes payable | — | 223,610 | — | (223,610) | — |
| Fair value of derivative instruments | — | 33,663 | — | — | 33,663 |
| Long-term debt, net of discounts | 1,160,498 | — | — | — | 1,160,498 |
| Other long-term liabilities | 2,359 | 79,643 | 376 | — | 82,378 |
| Partners' Capital: | | | | | |
| MarkWest Energy Partners, L.P. partners' capital | 1,168,008 | 512,508 | 429,300 | (946,322) | 1,163,494 |
| Non-controlling interest in consolidated subsidiaries | — | — | — | 233,951 | 233,951 |
| Total partners' capital | 1,168,008 | 512,508 | 429,300 | (712,371) | 1,397,445 |
| Total liabilities and partners' capital | $2,375,428 | $2,914,974 | $455,765 | $(2,849,904) | $2,896,263 |

## 20. Supplemental Condensed Consolidating Financial Information (Continued)

### Condensed Consolidating Statement of Operations

| | Three months ended September 30, 2009 | | | | |
|---|---|---|---|---|---|
| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| Total revenue | $ — | $202,183 | $15,508 | $ — | $217,691 |
| Operating expenses: | | | | | |
| Purchased product costs | — | 95,726 | 3,176 | — | 98,902 |
| Facility expenses | — | 27,570 | 4,049 | (107) | 31,512 |
| Selling, general and administrative expenses | 10,732 | 5,102 | 700 | (1,057) | 15,477 |
| Depreciation and amortization | 137 | 31,579 | 3,793 | (52) | 35,457 |
| Other operating expenses | — | 687 | 2 | — | 689 |
| Impairment of long-lived assets | — | — | — | — | — |
| Total operating expenses | 10,869 | 160,664 | 11,720 | (1,216) | 182,037 |
| (Loss) income from operations | (10,869) | 41,519 | 3,788 | 1,216 | 35,654 |
| Earnings from consolidated affiliates | 39,900 | 877 | — | (40,777) | — |
| Other (expense) income | (20,186) | (2,049) | 713 | (1,650) | (23,172) |
| Net income (loss) before provision for income tax | 8,845 | 40,347 | 4,501 | (41,211) | 12,482 |
| Provision for income tax expense | 131 | 447 | — | — | 578 |
| Net income (loss) | 8,714 | 39,900 | 4,501 | (41,211) | 11,904 |
| Net income attributable to non-controlling interest | — | — | — | (3,624) | (3,624) |
| Net income (loss) attributable to the Partnership | $ 8,714 | $ 39,900 | $ 4,501 | $(44,835) | $ 8,280 |

## 20. Supplemental Condensed Consolidating Financial Information (Continued)

| | Nine months ended September 30, 2009 | | | | |
|---|---|---|---|---|---|
| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| Total revenue | $ — | $482,222 | $28,905 | $ — | $ 511,127 |
| Operating expenses: | | | | | |
| Purchased product costs | — | 307,901 | 6,105 | — | 314,006 |
| Facility expenses | — | 83,783 | 10,499 | (215) | 94,067 |
| Selling, general and administrative expenses | 33,861 | 13,076 | 1,697 | (2,369) | 46,265 |
| Depreciation and amortization | 423 | 93,432 | 6,498 | (94) | 100,259 |
| Other operating expenses | — | 1,576 | 3 | — | 1,579 |
| Impairment of long-lived assets | — | — | 5,855 | — | 5,855 |
| Total operating expenses | 34,284 | 499,768 | 30,657 | (2,678) | 562,031 |
| (Loss) income from operations | (34,284) | (17,546) | (1,752) | 2,678 | (50,904) |
| Earnings from consolidated affiliates | (313) | 186 | — | 127 | — |
| Other (expense) income | (49,976) | (10,904) | 3,852 | (7,192) | (64,220) |
| Net (loss) income before provision for income tax | (84,573) | (28,264) | 2,100 | (4,387) | (115,124) |
| Provision for income tax benefit | (212) | (27,951) | — | — | (28,163) |
| Net (loss) income | (84,361) | (313) | 2,100 | (4,387) | (86,961) |
| Net income attributable to non-controlling interest | — | — | — | (1,914) | (1,914) |
| Net (loss) income attributable to the Partnership | $(84,361) | $ (313) | $ 2,100 | $(6,301) | $ (88,875) |

## 20. Supplemental Condensed Consolidating Financial Information (Continued)

### Condensed Consolidating Statement of Cash Flows

| | Nine months ended September 30, 2009 | | | | |
|---|---|---|---|---|---|
| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
| Net cash (used in) provided by operating activities | $ (61,492) | $ 210,814 | $ 3,151 | $ (4,608) | $ 147,865 |
| Cash flows from investing activities: | | | | | |
| Change in restricted cash | — | — | (10,025) | — | (10,025) |
| Equity investments | (39,038) | (129,871) | — | 162,474 | (6,435) |
| Distributions from consolidated affiliates | 10,803 | 31,152 | — | (41,955) | — |
| Collection of notes receivable | 7,790 | — | — | (7,790) | — |
| Capital expenditures | (738) | (164,282) | (228,090) | 4,608 | (388,502) |
| 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) provided by investing activities | (21,183) | (200,226) | (238,115) | 54,837 | (404,687) |
| Cash flows from financing activities: | | | | | |
| Proceeds from long-term debt | 685,000 | — | — | — | 685,000 |
| Payments of long-term debt | (700,900) | — | — | — | (700,900) |
| Payments of intercompany notes receivable, net | — | (7,790) | — | 7,790 | — |
| Payments for debt issuance costs, deferred financing costs and registration costs | (7,881) | (500) | — | — | (8,381) |
| Proceeds from SMR transaction | — | 73,129 | — | — | 73,129 |
| Proceeds from public offerings, net | 178,632 | — | — | — | 178,632 |
| Contributions to joint ventures, net | (5,464) | 39,038 | 273,436 | (162,474) | 144,536 |
| Proceeds from sale of equity interest in joint venture, net | (1,847) | — | — | 62,500 | 60,653 |
| Share-based payment activity | (1,257) | — | — | — | (1,257) |
| Payment of distributions | (112,525) | (10,803) | (31,232) | 41,955 | (112,605) |
| Intercompany advances, net | 48,917 | (48,917) | — | — | — |
| Net cash flows provided by (used in) financing activities | 82,675 | 44,157 | 242,204 | (50,229) | 318,807 |
| Net increase in cash | — | 54,745 | 7,240 | — | 61,985 |
| Cash and cash equivalents at beginning of year | — | — | 3,321 | — | 3,321 |
| Cash and cash equivalents at end of period | $ — | $ 54,745 | $ 10,561 | $ — | $ 65,306 |

## 21. Supplemental Disclosure of Changes in Partners' Capital

The following table provides a reconciliation of total partners' capital attributable to MarkWest Energy Partners, L.P. and total partners' capital attributable to the non-controlling interest for the nine months ended September 30, 2008 (in thousands).

| | MarkWest Energy Partners, L.P. Unitholders | | | | |
|---|---|---|---|---|---|
| | Common Units | Partners' Capital | Accumulated Other Comprehensive Income (loss) | Non-controlling Interest | Total |
| **December 31, 2007** | 22,861 | $ 38,463 | $ 928 | $ 524,583 | $ 563,974 |
| Option exercises | 98 | 375 | — | — | 375 |
| Common units issued for vested phantom units | 14 | 63 | — | — | 63 |
| Dividends paid | — | (4,338) | — | — | (4,338) |
| Distributions paid | — | (70,577) | — | — | (70,577) |
| Distributions to non-controlling interest holders | — | — | — | (19,651) | (19,651) |
| Share-based compensation related to equity awards | — | 8,251 | — | — | 8,251 |
| APIC pool for excess tax benefits related to share-based compensation | — | 717 | — | — | 717 |
| Acquisition of equity interest in Wirth Gathering Partnership | — | — | — | 2,924 | 2,924 |
| Other | — | — | — | 881 | 881 |
| *Merger and Redemption:* | | | | | |
| Redemption of MarkWest Hydrocarbon, Inc. Common Stock | (7,458) | (240,513) | — | — | (240,513) |
| Conversion of restricted stock to phantom units in connection with the Merger of MarkWest Hydrocarbon, Inc. and MarkWest Energy Partners, L.P. | (45) | — | — | — | — |
| Participation Plan liability settlement associated with the Merger of MarkWest Hydrocarbon, Inc. and MarkWest Energy Partners, L.P. | 946 | 30,078 | — | — | 30,078 |
| Purchase of non-controlling interest of MarkWest Energy Partners, L.P. | 34,474 | 1,095,917 | — | (502,297) | 593,620 |
| Issuance of units in public offering, net of offering costs | 5,750 | 171,395 | — | — | 171,395 |
| Net income (loss) | — | 27,930 | — | (3,271) | 24,659 |
| Realized loss on marketable securities | — | — | (928) | — | (928) |
| Comprehensive income | | | | | 23,731 |
| **September 30, 2008** | 56,640 | $1,057,761 | $ — | $ 3,169 | $1,060,930 |

**22. Subsequent Events**

The Partnership has evaluated subsequent events through November 9, 2009, the date the financial statements were issued, and identified the events disclosed below.

In January 2008, MarkWest Pioneer was granted the option to purchase a 10% membership interest in Midcontinent Express Pipeline LLC (“MEP”). MEP, owned by Energy Transfer Partners, L.P. and Kinder Morgan Energy Partners, L.P., is the owner and operator of the Midcontinent Express Pipeline, which runs from Bennington, Oklahoma to Perryville, Louisiana. On October 1, 2009, MarkWest Pioneer elected to forego the option to acquire the equity interest in MEP.

Effective November 1, 2009, the Partnership and M&R executed the Amended Liberty Agreement pursuant to which M&R will increase its participation in MarkWest Liberty Midstream by at least an additional $150.0 million. Additionally, the Partnership and M&R will maintain a 60%/40% respective ownership interest in MarkWest Liberty Midstream until January 1, 2011, at which time M&R’s ownership interest will increase from 40% to 49%. The Partnership and M&R will jointly fund the capital requirements of MarkWest Liberty Midstream at agreed upon levels until the Partnership’s contributed capital is proportionate to its 51% ownership interest (the “Equalization Date”), which is expected to occur on or before December 31, 2012. Following the Equalization Date, M&R will have pre-emptive rights to maintain its ownership interest in MarkWest Liberty Midstream in a range of between 45% and 49%. As a result of the execution of the Amended Liberty Agreement, the Partnership reconsidered the accounting treatment for MarkWest Liberty Midstream as a VIE and determined that the conclusions as discussed in Note 4 remain unchanged. The unexecuted form of the Amended Liberty Agreement is attached as Exhibit A to Exhibit 10.1 hereto.

Effective November 1, 2009, the Partnership sold its interest in Basin Pipeline, LLC (“Basin”) for nominal consideration. Basin owns a natural gas pipeline in Manistee, Mason and Oceana Counties in Michigan. The Partnership ceased its operations in western Michigan, including Basin, in July 2009. The Partnership’s loss on the disposal of Basin was immaterial.

## Item 2. 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 our condensed consolidated financial statements and accompanying notes included elsewhere in this report and our December 31, 2008 Annual Report on Form 10-K as modified by our Current Report on Form 8-K as filed with the SEC on May 18, 2009 for the retrospective applications of changes to the generally accepted accounting principles for the presentation of non-controlling interest and the calculation of earnings per share. These statements are based on current expectations and assumptions that are subject to risks and uncertainties. Actual results could differ materially from those expressed or implied in the forward-looking statements as a result of a number of factors.*

### 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 in the Appalachian region.

#### *Significant Financial and Other Highlights*

Significant financial and other highlights for the three months ended September 30, 2009 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 decreased approximately $20.7 million, or 20%, for the three months ended September 30, 2009 compared to the same period in 2008. The decrease is due primarily to significantly lower NGL and natural gas prices in 2009. The decrease related to commodity prices was partially offset by the following:
  - increased gathered and processed volumes in the Southwest segment due to the 2008 acquisition of the Stiles Ranch gathering system, the continued expansion of the Woodford gathering system including the start of operations for the Arkoma Connector Pipeline, and the expansion of the processing facilities in western Oklahoma and East Texas.
  - increased contracted volumes from a large producer and expansion of the processing facilities in the Northeast segment.
  - continued expansion of our Marcellus Shale operations in the Liberty segment which commenced in October 2008.
- During the three months ended September 30, 2009, the prices of NGLs relative to the price of crude oil have been significantly below the historical averages. This has reduced the effectiveness of our hedging program and has adversely impacted our cash flows and results of operations.
- In July 2009, we received the remaining $31.3 million in proceeds from the sale of a 50% equity interest in MarkWest Pioneer.
- In July 2009, we received an additional $50.0 million of contributions to MarkWest Liberty Midstream from M&R.
- In August 2009, we received net proceeds of $121.0 million from a public offering of approximately 6.03 million newly issued common units.
- In September 2009, we sold the SMR for proceeds of approximately $73.1 million.

***Net Operating Margin (a non-GAAP financial 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 usage of net operating margin and the underlying methodology in excluding certain charges is not necessarily an indication of the results of operations expected in the future, or that we will not, in fact, incur such charges in future periods.

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

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | **2009** | **2008** | **2009** | **2008** |
| Revenue | $207,933 | $ 303,560 | $576,300 | $866,760 |
| Purchased product costs | 91,086 | 171,539 | 274,052 | 479,747 |
| Net operating margin | 116,847 | 132,021 | 302,248 | 387,013 |
| Facility expenses | 30,165 | 28,213 | 93,945 | 75,641 |
| Total derivative (income) loss | (595) | (193,489) | 105,249 | 85,905 |
| Selling, general and administrative expenses | 15,477 | 15,331 | 46,265 | 54,406 |
| Depreciation | 25,264 | 17,510 | 69,621 | 48,533 |
| Amortization of intangible assets | 10,193 | 10,732 | 30,638 | 28,050 |
| Other operating expenses | 689 | 38 | 1,579 | 106 |
| Impairment of long-lived assets | — | — | 5,855 | 5,009 |
| Income (loss) from operations | $ 35,654 | $ 253,686 | $(50,904) | $ 89,363 |

***Our Contracts***

We generate the majority of our revenue and net operating margin (a non-GAAP measure, see above for discussion and reconciliation of net operating margin) from natural gas gathering, transportation and processing; NGL transportation, fractionation, marketing and storage; and crude oil gathering and transportation. We enter into a variety of contract types. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described below. We provide services under the following different 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 transmission of natural gas; transportation, fractionation and storage of NGLs; and gathering and transportation of crude oil. The revenue we earn from these arrangements is 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. In certain cases, our arrangements provide for minimum annual payments or fixed demand charges. If a sustained decline in commodity prices were to result in a decline in volumes, however, our revenues from these arrangements would be reduced.

- *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. Due to current market and financial conditions, we have seen decreases in natural gas, condensate and NGL prices, and it is uncertain if prices will remain at these lower levels in the future.

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

- *Keep-whole arrangements:* Under keep-whole arrangements, we gather natural gas from the producer, process the natural gas and sell 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, 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. Accordingly, under these arrangements our revenues and net operating margins increase as the price of condensate and NGLs increases relative to the price of natural gas, and decrease as the price of natural gas increases relative to the price of condensate and NGLs.

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

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

The following table is prepared as if we did not have an active commodity risk management program in place. 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 Condensed Consolidated Financial Statements. For the nine months ended September 30, 2009, we calculated the following approximate percentages of our revenue and net operating margin from the following types of contracts:

| | Fee-Based | Percent-of-Proceeds(1) | Percent-of-Index(2) | Keep-Whole(3) | Total |
|---|---|---|---|---|---|
| Revenue | 22% | 37% | 7% | 34% | 100% |
| Net operating margin | 41% | 27% | 3% | 29% | 100% |

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

(2) Includes settlement margin and other types of arrangements tied to natural gas prices.

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

While the percentages in the table above accurately reflect the percentages by contract type, we manage our business by taking into account the partial offset of short natural gas positions by long positions primarily in our Southwest segment, required levels of operational flexibility and the fact that our hedge plan is implemented on this basis. When the partial offset of our natural gas positions is considered, the calculated percentages for the net operating margin in the table above for percent-of-proceeds, percent-of-index and keep-whole contracts change to 43%, 0% and 16%, respectively.

### *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 the Appalachia area, 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.

## Results of Operations

### *Segment Reporting*

We classify our business in four reportable segments: Southwest, Northeast, Liberty and Gulf Coast. We capture information in this MD&A by segment. The segment information appearing in Note 19 of the accompanying Notes to the Condensed Consolidated Financial Statements is presented on a basis consistent with our internal management reporting.

### *Southwest*

- *East Texas.* Our East Texas system 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, which collectively form one of the largest natural gas producing regions in the United States. For natural gas that is processed in this segment, we purchase the NGLs from the producers primarily under percent-of-proceeds arrangements, or we transport volumes for a fee.
- *Oklahoma.* We own the Foss Lake natural gas gathering system and the Arapaho I and II natural gas processing plants, all located in Roger Mills, Custer and Ellis Counties of western Oklahoma. The gathering portion consists of a pipeline system that is connected to natural gas

wells and associated compression facilities. All of the gathered gas ultimately is compressed and delivered to the processing plant. We also own and operate a gathering system in the Granite Wash formation in the Texas panhandle that is connected to our Foss Lake processing plants and our Grimes gathering system that is located in Roger Mills and Beckham Counties in western Oklahoma. In addition, we own a natural gas gathering system in the Woodford Shale play in the Arkoma Basin of southeast Oklahoma. In July 2008, we acquired a subsidiary of PetroQuest Energy, L.L.C. ("PetroQuest") that owns natural gas gathering assets located primarily in Pittsburg County in southeast Oklahoma as part of our expansion of the Woodford gathering system.

On May 1, 2009, we entered into a joint venture with ArcLight in which ArcLight acquired a 50% equity interest in MarkWest Pioneer for a total purchase price of $62.5 million. MarkWest Pioneer is the owner and operator of the Arkoma Connector Pipeline, a 50-mile interstate pipeline that provides approximately 638,000 Dth/d of Woodford Shale takeaway capacity and interconnects with the Midcontinent Express Pipeline and the Gulf Crossing Pipeline. A complete discussion of the formation of and accounting treatment for MarkWest Pioneer appears in Note 4 of the accompanying Notes to the Condensed Consolidated Financial Statements.

- *Other Southwest.* We own a number of natural gas gathering systems in Texas, Louisiana, Mississippi and New Mexico, including the Appleby gathering system in Nacogdoches County, Texas. We gather a significant portion of the natural gas produced from fields adjacent to our gathering systems. 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.

***Northeast***

- *Appalachia.* We are the largest processor of natural gas in the Appalachian Basin, with fully integrated processing, fractionation, storage and marketing operations. The Appalachian Basin is a large natural gas producing region characterized by long-lived reserves and modest decline rates. Our Appalachian assets include the Kenova, Boldman, Cobb and Kermit natural gas processing plants, an NGL pipeline, the Siloam NGL fractionation plant and two caverns for storing propane.
- *Michigan.* We own and operate a crude oil pipeline in Michigan as well as a natural gas gathering system in Manistee County, Michigan.

***Liberty***

- *MarkWest Liberty Gas Gathering, L.L.C. and MarkWest Liberty Midstream & Resources, L.L.C.* We operate natural gas gathering systems and processing facilities located primarily in western Pennsylvania and northern West Virginia. Prior to February 27, 2009, we owned a 100% interest in these assets through MarkWest Liberty Gas Gathering, L.L.C., a wholly-owned subsidiary. On February 27, 2009, we contributed these assets to a newly-formed entity, MarkWest Liberty Midstream, and sold a 40% interest in MarkWest Liberty Midstream to M&R. Effective November 1, 2009, we and M&R executed the Amended Liberty Agreement that will increase M&R's ownership interest to 49% by January 1, 2011. A complete discussion of the formation of and accounting treatment for MarkWest Liberty Midstream appears in Note 4 of the accompanying Notes to the Condensed Consolidated Financial Statements. MarkWest Liberty Midstream currently operates a mechanical refrigeration plant with a design capacity of 60 MMcf/d and a cryogenic processing facility with a design capacity of 30 MMcf/d that was placed into service in the second quarter of 2009. We plan on adding a second cryogenic facility with a capacity of 120 MMcf/d by late 2009 or early 2010.

***Gulf Coast***

- *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.

The following summarizes the percentage of our revenue and net operating margin (a non-GAAP financial measure, see above) generated by our assets, by identifiable segment, for the nine months ended September 30, 2009:

| | Southwest | Northeast | Liberty | Gulf Coast | Total |
|---|---|---|---|---|---|
| Revenue | 59% | 29% | 5% | 7% | 100% |
| Net operating margin | 63% | 16% | 8% | 13% | 100% |

*Equity investments in unconsolidated affiliates*

*Starfish.* We own a 50% non-operating membership interest in Starfish, a joint venture with Enbridge Offshore Pipelines, L.L.C. that is accounted for using the equity method. The financial results of Starfish are included in *Earnings (loss) from unconsolidated affiliates* in the accompanying Condensed Consolidated Statements of Operations and are not included in our segment results. Starfish owns the FERC-regulated Stingray natural gas pipeline, and the unregulated Triton natural gas gathering system and West Cameron dehydration facility. All of these assets are located in the Gulf of Mexico or southwestern Louisiana.

*Centrahoma.* We own a 40% non-operating membership interest in Centrahoma, a joint venture with Antero Midstream Resources Corporation that is accounted for using the equity method. The financial results of Centrahoma are included in *Earnings (loss) from unconsolidated affiliates* in the accompanying Condensed Consolidated Statements of Operations and are not included in our segment results. Centrahoma owns certain processing plants in the Arkoma Basin. We have signed agreements to dedicate our processing rights in certain acreage in the Woodford Shale to Centrahoma through March 1, 2018.

***Three months ended September 30, 2009, compared to three months ended September 30, 2008***

Items below *Income (loss) from operations* in our Condensed 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. The tables below present information about operating income for the reported segments for the three months ended September 30, 2009 and 2008.

**Southwest**

| | Three months ended September 30, | | | |
|---|---|---|---|---|
| | 2009 | 2008 | $ Change | % Change |
| | (in thousands) | | | |
| Revenue | $123,792 | $192,675 | $(68,883) | (36)% |
| Operating expenses: | | | | |
| Purchased product costs | 53,425 | 120,208 | (66,783) | (56)% |
| Facility expenses | 17,893 | 16,670 | 1,223 | 7% |
| Total operating expenses before items not allocated to segments | 71,318 | 136,878 | (65,560) | (48)% |
| Portion of operating income attributable to non-controlling interests | 980 | — | 980 | N/A |
| Operating income before items not allocated to segments | $ 51,494 | $ 55,797 | $ (4,303) | (8)% |

*Revenue.* Revenue decreased primarily due to lower commodity prices. Revenue from NGL, natural gas and condensate sales decreased across the segment by $72.9 million. The change from a gas purchase contract to a gas gathering contract with a significant producer in the Other Southwest areas also contributed to the decline in revenue. The effect of the decrease in commodity prices on NGL sales was partially offset by increased volumes processed at our East Texas facilities and increased volumes processed at the Arapaho facilities associated with the Stiles Ranch gathering system that began operations in the fourth quarter of 2008. The revenue declines associated with lower commodity prices were also partially offset by a $4.7 million increase in gathering, treating, and transportation fee revenue due to the continued expansion of our operations in the Woodford, including the start of the Arkoma Connector Pipeline operations.

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

*Facility Expenses.* Facility expenses increased due primarily to the expansion of our western Oklahoma gathering and processing operations related to the development of Stiles Ranch, and increased repairs and maintenance resulting from the completed non-recurring environmental remediation costs in East Texas.

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

Operating results for the three months ended September, 30, 2008 were adversely impacted by business interruptions caused by Hurricane Ike. Management estimated that the financial impact of these business interruptions was a $2.6 million reduction of operating income. Excluding the impact of Hurricane Ike, operating income decreased $6.9 million, or 12%, during the three months ended September 30, 2009 compared to the same period in 2008.

**Northeast**

| | Three months ended September 30, | | | |
|---|---|---|---|---|
| | **2009** | **2008** | **$ Change** | **% Change** |
| | (in thousands) | | | |
| Revenue | $55,554 | $82,418 | $(26,864) | (33)% |
| Operating expenses: | | | | |
| Purchased product costs | 34,506 | 51,331 | (16,825) | (33)% |
| Facility expenses | 4,832 | 6,172 | (1,340) | (22)% |
| Total operating expenses before items not allocated to segments | 39,338 | 57,503 | (18,165) | (32)% |
| Operating income before items not allocated to segments | $16,216 | $24,915 | $ (8,699) | (35)% |

*Revenue.* Revenue decreased due primarily to lower commodity prices realized on NGL sales from the Appalachia region. The decrease in revenue from lower commodity prices was partially offset by increased volumes which resulted from upgrades to our processing facilities in this area, and increased volumes from a producer in the Appalachia region.

*Purchased Product Costs.* Purchased product costs decreased due to lower prices for the natural gas that must be purchased to satisfy the keep-whole arrangements in the Appalachia area. The effect of the lower prices was partially offset by the increase in volumes.

*Facility Expenses.* Facility expenses decreased due primarily to ceasing our natural gas gathering and processing operations in Western Michigan during the third quarter of 2009.

**Liberty**

| | Three months ended September 30, | | | |
|---|---|---|---|---|
| | **2009** | **2008** | **$ Change** | **% Change** |
| | (in thousands) | | | |
| Revenue | $12,790 | $— | $12,790 | N/A |
| Operating expenses: | | | | |
| Purchased product costs | 3,155 | — | 3,155 | N/A |
| Facility expenses | 3,435 | — | 3,435 | N/A |
| Total operating expenses before items not allocated to segments | 6,590 | — | 6,590 | N/A |
| Portion of operating income attributable to non-controlling interests | 2,470 | — | 2,470 | N/A |
| Operating income before items not allocated to segments | $ 3,730 | $— | $ 3,730 | N/A |

The results of operations for the three months ended September 30, 2009 include our operations in the northern West Virginia and western Pennsylvania areas. Revenue for the three months ended September 30, 2009 consists of approximately $8.1 million of gathering fees that are based primarily on a fixed return on the capital invested in the gathering system. Approximately $4.7 million of the revenue relates to NGL product sales under primarily percent-of-proceeds arrangements. The portion of operating income attributable to non-controlling interest represents M&R's 40% interest in the net operating income of MarkWest Liberty Midstream.

We did not have any operations in the Marcellus Shale during the three months ended September 30, 2008. We began construction in the second quarter of 2008 and commenced gas gathering and processing operations in the fourth quarter of 2008.

### Gulf Coast

| | Three months ended September 30, | | | |
|---|---|---|---|---|
| | 2009 | 2008 | $ Change | % Change |
| | (in thousands) | | | |
| Revenue | $15,797 | $28,467 | $(12,670) | (45)% |
| Operating expenses: | | | | |
| Facility expenses | 3,869 | 5,085 | (1,216) | (24)% |
| Total operating expenses before items not allocated to segments | 3,869 | 5,085 | (1,216) | (24)% |
| Operating income before items not allocated to segments | $11,928 | $23,382 | $(11,454) | (49)% |

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

*Facility Expenses.* Facility expenses decreased due primarily to lower electricity rates.

### Reconciliation of Segment Operating Income to Consolidated Income Before Provision for Income Tax

The following table provides a reconciliation of segment revenue to total revenue and operating income before items not allocated to segments to our consolidated income before provision for income tax for the three months ended September 30, 2009 and 2008. The ensuing items listed below the *Total* *segment revenue* and *Operating income* lines are not allocated to business segments as management does not consider these items allocable to any individual segment.

| | Three months ended September 30, 2009 | 2008 | $ Change | % Change |
|---|---|---|---|---|
| | (in thousands) | | | |
| Total segment revenue | $207,933 | $303,560 | $ (95,627) | (32)% |
| Derivative gain not allocated to segments | 9,758 | 262,811 | (253,053) | (96)% |
| Total revenue | $217,691 | $566,371 | $(348,680) | (62)% |
| Operating income before items not allocated to segments | $ 83,368 | $104,094 | $ (20,726) | (20)% |
| Portion of operating income attributable to non-controlling interests | 3,450 | — | 3,450 | N/A |
| Derivative gain not allocated to segments | 595 | 193,489 | (192,894) | (100)% |
| Compensation expense included in facility expenses not allocated to segments | (243) | (286) | 43 | (15)% |
| Facility expenses elimination | 107 | — | 107 | N/A |
| Selling, general and administrative expenses | (15,477) | (15,331) | (146) | 1% |
| Depreciation | (25,264) | (17,510) | (7,754) | 44% |
| Amortization of intangible assets | (10,193) | (10,732) | 539 | (5)% |
| Other operating expenses | (689) | (38) | (651) | 1,713% |
| Income from operations | 35,654 | 253,686 | (218,032) | (86)% |
| Earnings (loss) from unconsolidated affiliates | 169 | (196) | 365 | (186)% |
| Interest expense | (23,440) | (18,928) | (4,512) | 24% |
| Amortization of deferred financing costs and discount (a component of interest expense) | (3,091) | (1,080) | (2,011) | 186% |
| Derivative gain related to interest expense | 2,265 | — | 2,265 | N/A |
| Other income, net | 925 | 1,322 | (397) | (30)% |
| Income before provision for income tax | $ 12,482 | $234,804 | $(222,322) | (95)% |

*Derivative Gain Not Allocated to Segments.* Unrealized gain from the mark-to-market of our derivative instruments decreased by $201.7 million while realized loss from the settlement of our derivative instruments decreased by $8.8 million, due mainly to volatility in commodity prices when comparing prices in 2009 with 2008.

*Depreciation.* Depreciation increased due to depreciation on additional projects completed during the third quarter 2008 through the third quarter of 2009.

*Interest Expense.* Interest expense increased primarily due to additional borrowings in 2009 to fund our capital plan.

*Amortization of Deferred Financing Costs and Discount.* Amortization of deferred financing costs and discount increased due primarily to the amortization of the financing costs and discount on the Senior Notes issued in May 2009.

*Derivative Gain Related to Interest Expense.* Derivative gain related to interest expense relates to the unrealized gains on the interest rate swaps that we executed in July 2009, as discussed in Note 6 of the accompanying Notes to the Condensed Consolidated Financial Statements. We had no interest rate swaps outstanding during the three months ended September 30, 2008.

*Provision for Income Tax.* The total provision for income tax expense was $0.6 million which includes a deferred expense of $0.6 million related primarily to MarkWest Hydrocarbon's ownership of Class A units and the net unrealized derivative gains during the period. The current provision for income tax benefit was less than $0.1 million.

***Nine months ended September 30, 2009, compared to nine months ended September 30, 2008***

The tables below present information about operating income for the reported segments for the nine months ended September 30, 2009 and 2008.

**Southwest**

| | Nine months ended September 30, | | | |
|---|---|---|---|---|
| | 2009 | 2008 | $ Change | % Change |
| | (in thousands) | | | |
| Revenue | $339,967 | $536,563 | $(196,596) | (37)% |
| Operating expenses: | | | | |
| Purchased product costs | 150,456 | 322,370 | (171,914) | (53)% |
| Facility expenses | 55,703 | 45,189 | 10,514 | 23% |
| Total operating expenses before items not allocated to segments | 206,159 | 367,559 | (161,400) | (44)% |
| Portion of operating income attributable to non-controlling interests | 1,007 | — | 1,007 | N/A |
| Operating income before items not allocated to segments | $132,801 | $169,004 | $ (36,203) | (21)% |

*Revenue.* Revenue decreased primarily due to lower commodity prices. Revenue from NGL, natural gas and condensate sales decreased across the segment by $214.1 million. The change from a gas purchase contract to a gas gathering contract with a significant producer in the Other Southwest areas also contributed to the decline in revenue. The revenue decreases were partially offset by increased volumes processed at the Arapaho facilities associated with the Stiles Ranch gathering system that began operations in the fourth quarter of 2008 and by an increase of $18.0 million in gathering, treating, and transportation fee revenue due primarily to the continued expansion of our operations in the Woodford Shale, including the start of the Arkoma Connector Pipeline operations.

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

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

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

**Northeast**

| | Nine months ended September 30, 2009 | Nine months ended September 30, 2008 | $ Change | % Change |
|---|---|---|---|---|
| | (in thousands) | | | |
| Revenue | $165,765 | $251,115 | $(85,350) | (34)% |
| Operating expenses: | | | | |
| Purchased product costs | 117,540 | 157,377 | (39,837) | (25)% |
| Facility expenses | 14,796 | 16,161 | (1,365) | (8)% |
| Total operating expenses before items not allocated to segments | 132,336 | 173,538 | (41,202) | (24)% |
| Operating income before items not allocated to segments | $ 33,429 | $ 77,577 | $(44,148) | (57)% |

*Revenue.* Revenue decreased due mainly to lower commodity prices realized on NGL sales from the Appalachia region. The decrease in revenue from lower commodity prices was partially offset by increased volumes which resulted from upgrades to our processing facilities in this area and increased volumes from a large producer in the Appalachia region.

*Purchased Product Costs.* Purchased product costs decreased due to lower prices for the natural gas that must be purchased to satisfy the keep-whole arrangements in the Appalachia area. The effect of the lower prices was partially offset by the increase in volumes.

*Facility Expenses.* Facility expenses decreased due primarily to ceasing our natural gas gathering and processing operations in Western Michigan during the third quarter of 2009.

**Liberty**

| | Nine months ended September 30, 2009 | Nine months ended September 30, 2008 | $ Change | % Change |
|---|---|---|---|---|
| | (in thousands) | | | |
| Revenue | $29,510 | $— | $29,510 | N/A |
| Operating expenses: | | | | |
| Purchased product costs | 6,056 | — | 6,056 | N/A |
| Facility expenses | 10,557 | — | 10,557 | N/A |
| Total operating expenses before items not allocated to segments | 16,613 | — | 16,613 | N/A |
| Portion of operating income attributable to non-controlling interests | 4,113 | — | 4,113 | N/A |
| Operating income before items not allocated to segments | $ 8,784 | $— | $ 8,784 | N/A |

The results of operations for the nine months ended September 30, 2009 include our operations in the northern West Virginia and western Pennsylvania areas. Revenue for the nine months ended September 30, 2009 consists of approximately $20.7 million of gathering fees that are based primarily on a fixed return on the capital invested in the gathering system. Approximately $8.8 million of the revenue relates to NGL product sales under percent-of-proceeds arrangements. The portion of operating income attributable to non-controlling interest represents M&R's 40% interest in the net operating income of MarkWest Liberty Midstream.

We did not have any material operations in the Marcellus Shale during the nine months ended September 30, 2008. We began construction in the second quarter of 2008 and commenced gas gathering and processing operations in the fourth quarter of 2008.

**Gulf Coast**

| | Nine months ended September 30, | | | |
|---|---|---|---|---|
| | 2009 | 2008 | $ Change | % Change |
| | (in thousands) | | | |
| Revenue | $41,058 | $79,082 | $(38,024) | (48)% |
| Operating expenses: | | | | |
| Facility expenses | 12,303 | 13,341 | (1,038) | (8)% |
| Total operating expenses before items not allocated to segments | 12,303 | 13,341 | (1,038) | (8)% |
| Operating income before items not allocated to segments | $28,755 | $65,741 | $(36,986) | (56)% |

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

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

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

The following table provides a reconciliation of segment revenue to total revenue and operating income before items not allocated to segments to our consolidated (loss) income before provision for income tax for the nine months ended September 30, 2009 and 2008. The ensuing items listed below the *Total segment revenue* and *Operating income* lines are not allocated to business segments as management does not consider these items allocable to any individual segment.

| | Nine months ended September 30, | | | |
|---|---|---|---|---|
| | 2009 | 2008 | $ Change | % Change |
| | (in thousands) | | | |
| Total segment revenue | $ 576,300 | $866,760 | $(290,460) | (34)% |
| Derivative loss not allocated to segments | (65,173) | (96,030) | 30,857 | (32)% |
| Total revenue | $ 511,127 | $770,730 | $(259,603) | (34)% |
| Operating income before items not allocated to segments | $ 203,769 | $312,322 | $(108,553) | (35)% |
| Portion of operating income attributable to non-controlling interests | 5,120 | — | 5,120 | N/A |
| Derivative loss not allocated to segments | (105,249) | (85,905) | (19,344) | 23% |
| Compensation expense included in facility expenses not allocated to segments | (801) | (950) | 149 | (16)% |
| Facility expenses elimination | 215 | — | 215 | N/A |
| Selling, general and administrative expenses | (46,265) | (54,406) | 8,141 | (15)% |
| Depreciation | (69,621) | (48,533) | (21,088) | 43% |
| Amortization of intangible assets | (30,638) | (28,050) | (2,588) | 9% |
| Other operating expenses | (1,579) | (106) | (1,473) | 1,390% |
| Impairment of long-lived assets | (5,855) | (5,009) | (846) | 17% |
| (Loss) income from operations | (50,904) | 89,363 | (140,267) | (157)% |
| Earnings from unconsolidated affiliates | 1,260 | 1,932 | (672) | (35)% |
| Interest expense | (63,964) | (47,527) | (16,437) | 35% |
| Amortization of deferred financing costs and discount (a component of interest expense) | (6,528) | (7,287) | 759 | (10)% |
| Derivative gain related to interest expense | 2,265 | — | 2,265 | N/A |
| Other income, net | 2,747 | 4,640 | (1,893) | (41)% |
| (Loss) income before provision for income tax | $(115,124) | $ 41,121 | $(156,245) | (380)% |

*Derivative Loss Not Allocated to Segments.* Unrealized loss from the mark-to-market of our derivative instruments increased by $111.6 million while realized gain from the settlement of our derivative instruments increased by $92.2 million, due mainly to volatility in commodity prices when comparing prices in 2009 with 2008. Realized gains during 2009 also include net gains of $15.2 million due to the early settlement of certain positions during 2009 as discussed in Note 6 of the accompanying Notes to the Condensed Consolidated Financial Statements.

*Selling, General and Administrative Expenses.* Selling, general and administrative expenses decreased primarily due to lower expense related to share-based incentive compensation plans as the established targets for certain awards are not currently expected to be fully achieved. Additionally, we incurred $2.6 million of expenses related to the Merger during the nine months ended September 30, 2008, which did not recur in 2009.

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

*Impairment of Long-Lived Assets.* During the nine months ended September 30, 2009, we recognized an impairment of $5.9 million related to certain gas-gathering and intangible assets in the Southwest segment. During the nine months ended September 30, 2008, we recognized an impairment of $5.0 million related to certain gas-gathering assets in the Northeast segment. Refer to Note 10 of the accompanying Notes to the Condensed Consolidated Financial Statements for further discussion.

*Interest Expense.* Interest expense increased primarily due to additional borrowings in 2008 and 2009 to fund the Merger and our capital plan. The increase in interest expense was partially offset by a $4.2 million increase in capitalized interest.

*Other Income, Net.* Other income decreased primarily due to interest earnings on additional money market investments resulting from the cash raised in the debt and equity offerings in April 2008. Due to the Partnership's capital spending requirements, there was significant reduction in the excess cash available for short-term investments during the first nine months of 2009 and interest rates were lower on the amounts that were invested. Income from insurance proceeds was also $1.1 million less in 2009 compared to 2008.

*Provision for Income Tax.* The total provision for income tax benefit was $28.2 million which includes a deferred benefit of $34.7 million related primarily to MarkWest Hydrocarbon's ownership of Class A units and the net unrealized derivative loss during the period. The current provision for income tax expense was $6.5 million. Approximately $5.4 million is attributable to MarkWest Hydrocarbon, Inc. and the remaining $1.1 million is related to taxes payable by the Partnership associated with the Texas Margin Tax and Michigan Business Taxes.

*Operating Data*

| | Three months ended September 30, 2009 | Three months ended September 30, 2008 | % Change | Nine months ended September 30, 2009 | Nine months ended September 30, 2008 | % Change |
|---|---|---|---|---|---|---|
| **Southwest** | | | | | | |
| *East Texas* | | | | | | |
| Gathering systems throughput (Mcf/d) | 455,100 | 441,800 | 3.0% | 456,700 | 431,700 | 5.8% |
| NGL product sales (gallons) | 66,996,400 | 49,422,700 | 35.6% | 180,059,000 | 140,777,800 | 27.9% |
| *Oklahoma* | | | | | | |
| Foss Lake gathering system throughput (Mcf/d) | 82,200 | 94,200 | (12.7)% | 89,300 | 97,800 | (8.7)% |
| Stiles Ranch gathering system throughput (Mcf/d)(1) | 87,800 | N/A | N/A | 90,700 | N/A | N/A |
| Grimes gathering system throughput (Mcf/d) | 9,400 | 13,400 | (29.9)% | 10,100 | 13,400 | (24.6)% |
| Arapaho NGL product sales (gallons) | 33,723,900 | 20,327,200 | 65.9% | 92,854,000 | 62,487,300 | 48.6% |
| Southeast Oklahoma gathering systems throughput (Mcf/d) | 389,100 | 282,500 | 37.7% | 403,700 | 247,000 | 63.4% |
| Arkoma Connector Pipeline throughput (Mcf/d)(2) | 229,000 | N/A | N/A | 229,000 | N/A | N/A |
| *Other Southwest* | | | | | | |
| Appleby gathering system throughput (Mcf/d) | 44,200 | 58,200 | (24.1)% | 50,200 | 60,700 | (17.3)% |
| Other gathering systems throughput (Mcf/d)(3) | 10,500 | 12,000 | (12.5)% | 10,700 | 11,100 | (3.6)% |
| **Northeast** | | | | | | |
| *Appalachia*(4) | | | | | | |
| Natural gas processed (Mcf/d) | 197,200 | 202,900 | (2.8)% | 197,700 | 201,300 | (1.8)% |
| Keep-whole sales (gallons) | 26,668,300 | 27,482,700 | (3.0)% | 104,381,200 | 96,335,000 | 8.4% |
| Percent-of-proceeds sales (gallons) | 23,858,400 | 13,772,300 | 73.2% | 69,922,200 | 35,142,100 | 99.0% |
| Total NGL product sales (gallons)(5) | 50,526,700 | 41,255,000 | 22.5% | 174,303,400 | 131,477,100 | 32.6% |
| *Michigan* | | | | | | |
| Crude oil transported for a fee (Bbl/d) | 12,100 | 13,000 | (6.9)% | 12,400 | 13,500 | (8.1)% |
| **Liberty**(6) | | | | | | |
| Gathering systems throughput (Mcf/d) | 56,100 | N/A | N/A | 44,500 | N/A | N/A |
| NGL product sales (gallons) | 10,558,900 | N/A | N/A | 18,995,200 | N/A | N/A |
| **Gulf Coast** | | | | | | |
| Refinery off-gas processed (Mcf/d) | 127,800 | 120,100 | 6.4% | 119,000 | 123,400 | (3.6)% |
| Liquids fractionated (Bbl/d) | 24,500 | 24,200 | 1.2% | 23,200 | 24,700 | (6.1)% |

(1) We acquired the Stiles Ranch gathering system in August 2008, and completed construction of a 60-mile pipeline connecting the system to our Arapaho processing plants in November 2008.

(2) We began commercial operation of the Arkoma Connector Pipeline in July 2009.

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

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

(5) Represents sales at the Siloam fractionator. The total sales in 2009 exclude 6.6 million gallons and 13.1 million gallons sold by the Northeast on behalf of Liberty for the three and nine months ended September 30, 2009, respectively.

(6) We began natural gas gathering and processing operations in the Marcellus Shale in October 2008.

**Liquidity and Capital Resources**

In 2008 we spent approximately $638.6 million on organic growth projects and two third-party acquisitions. We also completed the Merger with MarkWest Hydrocarbon. Our 2009 capital plan includes approximately $465.0 million of capital expenditures for board-approved growth projects, of which a significant portion will be funded by our joint venture partners and by our divestiture of the SMR facility as discussed in the *Alternative Financing* section below, plus approximately $5.0 million to $10.0 million for maintenance capital. As of September 30, 2009 we have spent approximately $388.5 million, including the amounts funded by our joint venture partners.

Our 2010 capital plan includes approximately $480.0 million of capital expenditures for growth projects and approximately $10.0 million to $15.0 million for maintenance capital. Our share of growth capital expenditures is expected to be approximately $300.0 million and the remainder will be funded through contributions from our joint venture partners during 2009 and 2010.

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 and access to debt and equity markets, both public and private. In response to the recent turmoil in the capital markets, we have utilized alternative financing strategies such as entering into joint venture arrangements and sales of non-strategic assets. During the nine months ended September 30, 2009, we completed the following transactions that have improved our liquidity position:

- amended our Partnership Credit Agreement to increase our borrowing capacity under the revolving credit facility from $350.0 million to $435.6 million.
- received net proceeds of $113.8 million from a private placement of senior notes.
- received total net proceeds of $178.6 million from two public offerings of common units.
- entered into a joint venture agreement with M&R to partially fund our growth plan in the Marcellus Shale region. As of September 30, 2009, we have received net proceeds of $144.5 million.
- entered into a joint venture agreement with ArcLight and received net proceeds of $60.7 million to finance a significant portion of the cost of the Arkoma Connector Pipeline.
- sold the SMR for approximately $73.1 million.

As a result of these financing activities, which are discussed in further detail below, management believes that expenditures for our current capital projects will be funded with cash flows from operations, current cash balances, contributions by our joint venture partners and our current borrowing capacity under the expanded revolving credit facility. However, it may be necessary to raise additional funds to finance our future capital requirements.

*Debt Financing Activities*

Effective March 2, 2009, the revolving credit facility was amended in order to accommodate the MarkWest Liberty Midstream joint venture with M&R and the available credit was expanded to $435.6 million to provide additional liquidity. Under the terms of the amendment, the accordion feature was reset to $200.0 million of uncommitted funds. The term of the original credit agreement has been reduced by one year and is now due on February 20, 2012. Under the provisions of the Partnership Credit Agreement we are subject to a number of restrictions and covenants. These covenants are used to calculate the available borrowing capacity on a quarterly basis. As of November 2, 2009, we had no borrowings outstanding and $32.5 million of letters of credit outstanding under the revolving credit facility, leaving $403.1 million available for borrowing.

On May 26, 2009, we completed a private placement of $150.0 million in aggregate principal amount of 6.875% senior unsecured notes due 2014 to qualified institutional buyers under Rule 144A. We received proceeds of approximately $113.8 million, after deducting initial purchasers' discounts and the expenses of the private placement. The proceeds were primarily used to repay borrowings under the Partnership's revolving credit facility.

As of September 30, 2009, we had four series of Senior Notes outstanding: $225.0 million aggregate principal issued in October 2004 and due November 2014; $275.0 million aggregate principal issued in July 2006 and due July 2016; $500.0 million aggregate principal issued in April 2008 and due April 2018; and $150.0 million aggregate principal issued in May 2009 and due November 2014. For further discussion of the Senior Notes see Note 12 of the accompanying Notes to the Condensed Consolidated Financial Statements.

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

The Partnership Credit Agreement limits our ability to enter into transactions with parties that require margin calls under certain derivative instruments. The Partnership Credit Agreement prevents members of the participating bank group from requiring margin calls. As of November 2, 2009, approximately 94% of our derivative positions, measured volumetrically, 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; however, there is no certainty that the members of our bank group will continue to participate and in such case, a portion of our available credit could be used for derivative instruments instead of future growth.

In July 2009, we entered into fixed-to-variable interest rate swap agreements having a combined notional principal amount of $275.0 million. The swaps are intended to hedge against changes in fair value due to changes in the benchmark interest rate (one-month LIBOR). We are hedging a portion of our senior notes that mature on November 1, 2014. For further discussion of the interest rate swaps, see Note 6 and Note 7 of the accompanying Notes to the Condensed Consolidated Financial Statements.

*Equity Offerings*

On August 18, 2009, we completed a public offering of approximately 6.03 million newly issued common units, which included the exercise of the overallotment option by the underwriters, representing limited partner interests at a purchase price of $20.95 per common unit. Net proceeds of approximately $121.0 million were used to partially fund our 2009 capital expenditure requirements and the remainder was used to pay down borrowings under our revolving credit facility of the Partnership Credit Agreement.

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

*Alternative Financing Arrangements*

On February 27, 2009, we entered into a joint venture agreement in which M&R acquired a 40% interest in MarkWest Liberty Midstream (see Note 4 of the accompanying Notes to the Condensed Consolidated Financial Statements for further details of the joint venture agreement). MarkWest Liberty Midstream operates our natural gas midstream business in and around the Marcellus Shale in western Pennsylvania and northern West Virginia. As noted above, our 2009 growth capital plan is $465.0 million, of which approximately $170.0 million relates to projects included within MarkWest Liberty Midstream. In accordance with the joint venture agreement, M&R will make contributions of at least $200.0 million to MarkWest Liberty Midstream in 2009, offsetting our total 2009 cash requirements. M&R contributed $150.0 million during the nine months ended September 30, 2009 and $50.0 million in October 2009.

Effective November 1, 2009, we and M&R executed the Amended Liberty Agreement. Under the Amended Liberty Agreement, M&R will increase its participation in MarkWest Liberty Midstream by at least an additional $150.0 million. Additionally, we and M&R will maintain a 60%/40% respective ownership interest in MarkWest Liberty Midstream until January 1, 2011, at which time M&R's ownership interest will increase from 40% to 49%. We and M&R will jointly fund the capital requirements of MarkWest Liberty Midstream at agreed upon levels until our contributed capital is proportionate to our 51% ownership interest, which is expected to occur on or before December 31, 2012. Following the Equalization Date, M&R will have pre-emptive rights to maintain its ownership interest in MarkWest Liberty Midstream in a range of between 45% and 49%. MarkWest Liberty Midstream's capital plan for 2010 through 2012 has not been finalized, so the exact timing of the contributions by both parties is currently uncertain. If the Equalization Date has not occurred by December 31, 2012, M&R may elect that we contribute the amount of the shortfall, or may elect that we continue to fund 100% of MarkWest Liberty Midstream's capital expenditures until our total contributed capital is proportionate to our 51% ownership interest.

On May 1, 2009, we entered into a joint venture with ArcLight. The joint venture entity, MarkWest Pioneer, operates a 50-mile interstate pipeline that connects our gathering systems in the Woodford Shale to the Midcontinent Express Pipeline and the Gulf Crossing Pipeline. ArcLight acquired a 50% equity interest in MarkWest Pioneer for a total purchase price of $62.5 million. At closing, ArcLight contributed cash of $31.25 million and contributed an additional $31.25 million in July 2009, corresponding with the pipeline's commercial operations date. We retain a 50% equity interest and we are obligated to fund all capital expenditures necessary to complete construction of the Arkoma Connector Pipeline in excess of $125.0 million.

On September 1, 2009, we completed the sale of the SMR currently being constructed at our Javelina gas processing and fractionation facility in Corpus Christi, Texas. Under the terms of the agreement, we received proceeds of $73.1 million and the purchaser will complete the construction of the SMR. A related hydrogen supply agreement was executed under which we will receive all of the hydrogen produced by the SMR for the next 20 years in exchange for processing fees and the reimbursement of certain other expenses. In accordance with generally accepted accounting principles, we are 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; not an asset sale. We used the proceeds from the transaction to pay down amounts outstanding under our revolving credit facility and for the continued development of other strategic projects.

*Liquidity Risks and Uncertainties*

The level of uncertainty that currently exists in the financial markets has created an increased risk of counterparty default that could impact our liquidity in several ways. During 2009, we expect that we will continue to borrow additional amounts under our revolving credit facility. However, our ability to access these funds could be adversely impacted by the failure of one or more of the members of the participating bank group. Although management believes that the participating members are financially sound, an increased risk does exist. Also, because the participating members of our bank group are the counterparties to most of our derivative instruments, the failure of one of more members could significantly reduce the cash flows from operations related to the settlement of these positions. The cash flows generated by our operations could also be significantly reduced if any of our major customers defaulted. The credit worthiness of our trade customers is continuously monitored, and we believe that our current group of customers are sound and represent no abnormal credit risk.

Our ability to pay distributions to our unitholders and to fund planned capital expenditures and make acquisitions will depend upon our future operating performance. That, in turn, will be affected by prevailing economic conditions in our industry, as well as financial, business and other factors, some of which are beyond our control. The current global economic uncertainty has had a significant adverse impact on the availability of capital funding and on commodity prices. Although NGL and natural gas prices have improved somewhat during the third quarter of 2009, our operating performance could continue to be negatively impacted if the improvements in commodity prices are not sustained.

*Cash Flow*

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

| | Nine months ended September 30, | | |
|---|---|---|---|
| | **2009** | **2008** | **Change** |
| Net cash provided by operating activities | $ 147,865 | $ 216,132 | $ (68,267) |
| Net cash flows used in investing activities | (404,687) | (648,794) | 244,107 |
| Net cash flows provided by financing activities | 318,807 | 499,880 | (181,073) |

Net cash provided by operating activities decreased primarily due to a $108.6 million decrease in operating income, excluding derivative gains and losses, in our operating segments, which was offset by an increase of $92.2 million in net cash received from the settlement of derivative positions. The cash provided by operations for the nine months ended September 30, 2008 also included $40.3 million of inflows from the return of margin deposits which did not recur in 2009.

Net cash used in investing activities decreased primarily due to cash paid as consideration in the Merger of $269.9 million in 2008.

Net cash provided by financing activities decreased primarily due to the $459.1 million decrease of net borrowings on long-term debt. This decrease was offset by $144.7 million in net contributions from M&R to MarkWest Liberty Midstream, $60.7 million in net proceeds from the sale of equity interests in the Arkoma joint venture, and $73.1 million in net proceeds from the SMR financing arrangement.

**Contractual Obligations**

We periodically make other commitments and become subject to other contractual obligations that we believe to be routine in nature and incidental to the operation of the business. Management believes that such routine commitments and contractual obligations do not have a material impact on our business, financial condition or results of operations. As of September 30, 2009, our purchase obligations for the remainder of 2009 were $36.5 million compared to our 2009 obligations of $111.2 million as of December 31, 2008. Purchase obligations represent purchase orders and contracts related to property, plant and equipment. During the third quarter of 2009, we entered a long-term agreement to pay monthly processing fees in exchange for all of the hydrogen supplied by the SMR. Refer to Note 18 of the accompanying Notes to the Condensed Consolidated Financial Statements for further discussion.

## Matters Impacting Future Results

Due to significant hurricane damage to oil and gas producing assets in the Gulf Coast area in recent years, insurance costs within this region have increased substantially. In response to these increasing costs and deductibles, we will no longer insure our interest in Starfish against future business interruption and property damage caused by named windstorms. As a result, our annual savings on insurance premiums compared to historical annual costs will be approximately $1.7 million. Our annual savings compared to the current cost of maintaining coverage against named windstorms is approximately $4.5 million. However, if a significant uninsured event occurs with respect to Starfish, it could adversely affect our operations and cash flows available for distribution to our unitholders.

## Critical Accounting Policies

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 are used in accounting for, among other items, valuing inventory; valuing identified intangible assets; evaluating impairments of long-lived assets, goodwill and equity investments; share-based compensation; and accounting for risk management activities and derivative financial instruments.

There have not been any material changes during the nine months ended September 30, 2009 to the methodology applied by management for critical accounting policies previously disclosed in *Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies* in our 2008 Annual Report on Form 10-K, except as noted below.

| Description | Judgments and Uncertainties | Effect if Actual Results Differ from Estimates and Assumptions |
|---|---|---|
| *Impairment of Long-Lived Assets* | | |
| We evaluate our long-lived assets, including intangibles, for impairment when events or changes in circumstances warrant such a review. A long-lived asset group is considered impaired when the estimated undiscounted cash flows from such asset group are less than the asset group's carrying value. In that event, a loss is recognized to the extent that the carrying value exceeds the fair value of the long-lived asset group. | We consider the volume of reserves behind the asset and future NGL product and natural gas prices to estimate cash flows for each asset group. The amount of additional reserves developed by future drilling activity depends, in part, on expected commodity prices. Projections of reserves, drilling activity and future commodity prices are inherently subjective and contingent upon a number of variable factors, many of which are difficult to forecast. | As a result of an impairment analysis completed as of June 30, 2009, we wrote down the value of long-lived assets for Wirth Gathering Partnership to zero resulting in a $5.9 million impairment expense. As of September 30, 2009, there were no indicators of additional impairment.<br><br>A significant variance in any of the assumptions or factors considered to determine if an impairment indicator existed at September 30, 2009 could result in the potential impairment of an asset. A 10% decrease in the estimated future cash flows used in the assessment of impairment indicators would not have indicated a potential impairment. |

| Description | Judgments and Uncertainties | Effect if Actual Results Differ from Estimates and Assumptions |
|---|---|---|
| *Variable Interest Entities* | | |
| When we own less than a 100% interest in an entity, we must evaluate our interests to determine if we hold a variable interest in that entity. A variable interest can be contractual, ownership, or other economic interests in an entity that change with changes in the fair value of the entity.<br><br>When we conclude that we hold a variable interest in an entity we must determine if we are the entity's primary beneficiary. A primary beneficiary absorbs a majority of the entity's expected losses or residual returns, or both. | Significant judgment is exercised in evaluating the nature of our interest in an entity and our status as the primary beneficiary.<br><br>We use qualitative and quantitative analysis to evaluate our interest in an entity primarily to determine if (a) the entity has insufficient equity at risk to finance its own activities and needs continuing financial support; (b) the equity holders of the entity lack the traditional characteristics of a controlling financial interest; or (c) if an equity holder's voting interests are disproportionate to its obligation to absorb expected losses. | Our interests in MarkWest Liberty Midstream and MarkWest Pioneer are considered to be variable interests and we are considered the primary beneficiary. Changes in the design or nature of MarkWest Liberty Midstream or MarkWest Pioneer, or our involvement with either of these entities may require us to reconsider our conclusions on the entity as a variable interest entity and our status as the primary beneficiary. Such reconsideration could result in the deconsolidation of MarkWest Liberty Midstream or MarkWest Pioneer. The deconsolidation would have a significant impact on our financial statements. |
| We consolidate all variable interest entities when we determine that we are the primary beneficiary. | We evaluate whether we are the primary beneficiary of a variable interest entity by qualitatively evaluating our level of involvement in the design of the entity, and determining if the entity's activities are substantially conducted on our behalf. A combination of qualitative and quantitative analysis is used to determine if we provide more than half of required continuing financial support to the entity, or if we absorb a majority of the entity's expected losses or returns.<br><br>After initial analysis when reconsideration events occur, we evaluate an entity and our status as the primary beneficiary to determine if the nature of our interest in the entity has changed or if the design or activities of the entity have changed. | We own less than a 100% interest in several other entities including Wirth Gathering Partnership, Brightstar Partnership, Starfish and Centrahoma. We have determined that none of these entities are a variable interest entity. However, changes in the design or nature of these entities or in our involvement with these entities may require us to reconsider our conclusions. Such reconsideration could change the decision of whether or not to consolidate each of these entities. The deconsolidation of an entity that is currently consolidated or the consolidation of an entity that is currently accounted for under the equity method could have a significant impact on our financial statements. |

### Recent Accounting Pronouncements

Refer to Note 3 of the accompanying Condensed Consolidated Financial Statements for information regarding recent accounting pronouncements.

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

The information about market risk for the nine months ended September 30, 2009 does not differ materially from that discussed in Item 7A. *Quantitative and Qualitative Disclosures about Market Risk* of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2008. Refer to Note 6 of the accompanying Notes to the Condensed Consolidated Financial Statements for any updates to our quantitative and qualitative disclosures about market risk.

The following tables provide information on the volume of our commodity derivative activity for positions related to long liquids and keep-whole price risk entered into subsequent to September 30, 2009.

| WTI Crude Swaps | Volumes (Bbl/d) | WAVG Price (Per Bbl) |
|---|---|---|
| 2010 | 150 | $83.18 |

| Propane Swaps | Volumes (Gal/d) | WAVG Price (Per Gal) |
|---|---|---|
| 2010 | 26,548 | $1.05 |

| Isobutane Swaps | Volumes (Gal/d) | WAVG Price (Per Gal) |
|---|---|---|
| 2010 | 5,355 | $1.42 |

| Normal Butane Swaps | Volumes (Gal/d) | WAVG Price (Per Gal) |
|---|---|---|
| 2010 | 8,742 | $1.29 |

| Natural Gasoline Swaps | Volumes (Gal/d) | WAVG Price (Per Gal) |
|---|---|---|
| 2010 | 10,492 | $1.65 |

| Natural Gas Swaps | Volumes (MMBtu/d) | WAVG Price (Per MMBtu) |
|---|---|---|
| 2010 | 5,023 | $5.59 |

The following tables provide information on the volume of our taxable subsidiary's commodity derivative activity for positions related to keep-whole price risk entered into subsequent to September 30, 2009.

| WTI Crude Swaps | Volumes (Bbl/d) | WAVG Price (Per Bbl) |
|---|---|---|
| 2010 | 422 | $82.95 |

| Natural Gas Swaps | Volumes (MMBtu/d) | WAVG Price (Per MMBtu) |
|---|---|---|
| 2009 | 11,667 | $5.06 |
| 2010 | 2,233 | 5.94 |

## Item 4. Controls and Procedures

*Evaluation of Disclosure Controls and Procedures*

As of September 30, 2009, 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 the Partnership's disclosure controls and procedures as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, the Partnership's management, including the Chief Executive Officer and Chief Financial Officer, concluded the Partnership's disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by the Partnership in reports that it files or submits under the Exchange Act is (a) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms and (b) accumulated and communicated to the Partnership's management, including the Chief Executive Officer and the Chief Financial Officer, to allow timely decisions regarding required disclosure.

*Changes in Internal Control Over Financial Reporting*

There has been no change in our internal control over financial reporting during the quarter ended September 30, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

# PART II—OTHER INFORMATION

## Item 1. Legal Proceedings

Refer to Note 18 of the accompanying Notes to the Condensed Consolidated Financial for information regarding legal proceedings.

## Item 1A. Risk Factors

There has been no material change in the risk factors set forth in Part I, Item 1A. *Risk Factors* in our Annual Report on Form 10-K for the year ended December 31, 2008, except as set forth below.

***Alternative financing strategies may not be successful.***

Periodically, we will consider the use of alternative financing strategies such as joint venture arrangements and the sale of non-strategic assets. Joint venture agreements may not share the risks and rewards of ownership in proportion to the voting interests. Joint venture arrangements may require us to pay certain costs or to make certain capital investments and we may have little control over the amount or the timing of these payments and investments. We may not be able to negotiate terms that adequately reimburse us for our costs to fulfill service obligations for those joint ventures where we are the operator. In addition, our joint venture partners may be unable to meet their economic or other obligations and we may be required to fulfill those obligations alone. We may periodically sell assets or portions of our business. Separating the existing operations from our assets or operations of which we dispose may result in significant expense and accounting charges, disrupt our business or divert management's time and attention. We may not achieve expected cost savings from these dispositions or the proceeds from sales of assets or portions of our business may be lower than the net book value of the assets sold. We may not be relieved of all of our obligations related to the assets or businesses sold.

These factors could have a material adverse effect on our revenues, income from operations, cash flows and our quarterly distribution on our common units.

***The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.***

Congress is currently considering legislation that would impose restrictions on certain transactions involving commodity derivatives. Additionally, the Treasury Department recently indicated that it intends to propose legislation to subject all OTC derivative dealers and all other major OTC derivative market participants to substantial supervision and regulation, including imposing conservative capital and margin requirements and strong business conduct standards. The adoption of laws or regulations that restrict the use of derivatives or increase the costs of derivative transactions could adversely affect our ability to hedge our commodity price risk and could negatively affect our results of operations, financial condition and cash flow available for distribution.

***Our variable rate debt makes us vulnerable to increases in interest rates.***

As of November 2, 2009, we had consolidated debt outstanding with an aggregate principal amount of $1,150 million (excluding the fair value of interest rate swaps). Of this amount, approximately $275 million was subject to variable interest rates, either as variable rate debt outstanding under our revolving credit facility or as long-term fixed rate debt converted to variable rates through the use of interest rate swaps. If interest rates increase significantly, the amount of cash required to service our debt would increase and our earnings could be adversely affected. For further discussion of the interest rate swaps, see Note 6 and Note 7 of the accompanying Notes to the Condensed Consolidated Financial Statements.

***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 recently proposed implementation of International Financial Reporting Standards ("IFRS"), could change our current application of GAAP, resulting in a material adverse impact on our financial position or results of operations.

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

As a public entity, 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 the Partnership. 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 the Partnership, 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.

### Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

### Item 3. Defaults Upon Senior Securities

None.

### Item 4. Submission of Matters to a Vote of Security Holders

None.

### Item 5. Other Information

None.

### Item 6. Exhibits

| | |
|---|---|
| 10.1*+ | Letter Agreement dated August 10, 2009 between MarkWest Liberty Gas Gathering, L.L.C. and M&R MWE Liberty, LLC. |
| 31.1* | Certification of the Chief Executive Officer pursuant to Rule 13a-14(a) of the Securities Exchange Act, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31.2* | Certification of the Chief Financial Officer pursuant to Rule 13a-14(a) of the Securities Exchange Act, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32.1* | Certification of the Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 32.2* | Certification of the Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |

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* Filed herewith

\+ 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.

## SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

MarkWest Energy Partners, L.P.
(Registrant)

By: MarkWest Energy GP, L.L.C.,
Its General Partner

Date: November 9, 2009

/s/ FRANK M. SEMPLE

Frank M. Semple
*Chairman, President and Chief Executive Officer*
*(Principal Executive Officer)*

Date: November 9, 2009

/s/ NANCY K. BUESE

Nancy K. Buese
*Senior Vice President & Chief Financial Officer*
*(Principal Financial Officer and*
*Principal Accounting Officer)*

**Exhibit 31.1**

**CERTIFICATION**

I, Frank M. Semple, certify that:

1. I have reviewed this quarterly report on Form 10-Q of MarkWest Energy Partners, L.P.

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

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

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

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

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

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

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

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

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

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

Date: November 9, 2009

By: /s/ FRANK M. SEMPLE

Frank M. Semple
*Chairman, President and Chief Executive Officer*
*(Principal Executive Officer)*

**Exhibit 31.2**

**CERTIFICATION**

I, Nancy K. Buese, certify that:

1. I have reviewed this quarterly report on Form 10-Q of MarkWest Energy Partners, L.P.
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report.
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report.
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f), for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2009

By: /s/ NANCY K. BUESE

Nancy K. Buese
*Senior Vice President & Chief Financial Officer*
*(Principal Financial Officer and*
*Principal Accounting Officer)*

**Exhibit 32.1**

**CERTIFICATION PURSUANT TO**
**18 U.S.C. SECTION 1350,**
**AS ADOPTED PURSUANT TO**
**SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of MarkWest Energy Partners, L.P. (the "Partnership"), on Form 10-Q for the period ending September 30, 2009, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Frank M. Semple, Chief Executive Officer of the General Partner of the Partnership, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

Date: November 9, 2009

By: /s/ FRANK M. SEMPLE

Frank M. Semple
*Chairman, President and Chief Executive Officer*
*(Principal Executive Officer)*

This certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document. This certification shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or otherwise subject to liability under that section. This certification shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act except to the extent this Exhibit 32.1 is expressly and specifically incorporated by reference in any such filing.

A signed original of this written statement required by Section 906 has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

**Exhibit 32.2**

**CERTIFICATION PURSUANT TO**
**18 U.S.C. SECTION 1350,**
**AS ADOPTED PURSUANT TO**
**SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of MarkWest Energy Partners, L.P. (the "Partnership") on Form 10-Q for the period ending September 30, 2009, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Nancy K. Buese, Chief Financial Officer of the General Partner of the Partnership, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

Date: November 9, 2009

By: /s/ NANCY K. BUESE

Nancy K. Buese
*Senior Vice President & Chief Financial Officer*
*(Principal Financial Officer and Principal Accounting Officer)*

This certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document. This certification shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or otherwise subject to liability under that section. This certification shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act except to the extent this Exhibit 32.2 is expressly and specifically incorporated by reference in any such filing.

A signed original of this written statement required by Section 906 has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.