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 March 31, 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 May 4, 2009, was 56,893,885.

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 (the "Merger").

Glossary of Terms

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
Gal/d	gallons per day
Mcf/d	one thousand cubic feet of natural gas per day
MMBtu	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)	Revenues, 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

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

MARKWEST ENERGY PARTNERS, L.P.

Condensed Consolidated Balance Sheets

(unaudited, in thousands)

	March 31, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 32,001	$ 3,321
Receivables, net of allowances of $177 and $175, respectively	80,318	101,849
Inventories	13,508	31,556
Fair value of derivative instruments	72,082	126,949
Other current assets	11,253	11,748
Total current assets	209,162	275,423
Property, plant and equipment	1,817,058	1,650,692
Less: accumulated depreciation	(99,995)	(81,167)
Total property, plant and equipment, net	1,717,063	1,569,525
Other long-term assets:		
Investment in unconsolidated affiliates	50,971	46,092
Intangibles, net of accumulated amortization of $53,205 and $42,972, respectively	685,684	695,917
Goodwill	9,421	9,421
Deferred financing costs, net of accumulated amortization of $3,855 and $3,248, respectively	19,930	16,682
Deferred contract cost, net of accumulated amortization of $1,404 and $1,326, respectively	1,846	1,924
Fair value of derivative instruments	51,725	55,389
Other long-term assets	6,242	2,681
Total other long-term assets	825,819	828,106
Total assets	$2,752,044	$2,673,054
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 54,851	$ 72,837
Accrued liabilities	124,464	111,034
Deferred income taxes	2,682	2,682
Fair value of derivative instruments	37,960	37,633
Total current liabilities	219,957	224,186
Deferred income taxes	31,874	47,465
Fair value of derivative instruments	22,861	14,801
Long-term debt, net of discounts of $11,270 and $11,735, respectively	1,283,130	1,172,965
Other long-term liabilities	6,637	5,878
Commitments and contingencies (Note 18)		
Partners' Capital:		
MarkWest Energy Partners, L.P. partners' capital (56,894 and 56,640 common units outstanding, respectively)	1,134,304	1,204,458
Non-controlling interest in consolidated subsidiaries	53,281	3,301
Total partners' capital	1,187,585	1,207,759
Total liabilities and partners' capital	$2,752,044	$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 March 31,	
	2009	**2008**
Revenue:		
Revenue	$183,367	$285,042
Derivative gain (loss)	8,304	(46,250)
Total revenue	191,671	238,792
Operating expenses:		
Purchased product costs	102,314	154,935
Derivative loss (gain) related to purchased product costs	29,513	(31,997)
Facility expenses	31,444	22,666
Derivative gain related to facility expenses	(371)	(43)
Selling, general and administrative expenses	15,927	22,461
Depreciation	20,943	14,525
Amortization of intangible assets	10,233	6,849
Loss on disposal of property, plant and equipment	729	3
Accretion of asset retirement obligations	47	32
Total operating expenses	210,779	189,431
(Loss) income from operations	(19,108)	49,361
Other income (expense):		
(Loss) earnings from unconsolidated affiliates	(105)	1,551
Interest income	41	514
Interest expense	(17,782)	(11,149)
Amortization of deferred financing costs and discount (a component of interest expense)	(1,391)	(1,043)
Miscellaneous expense	(662)	(33)
(Loss) income before provision for income tax	(39,007)	39,201
Provision for income tax (benefit) expense:		
Current	6,253	10,767
Deferred	(15,591)	12,676
Total provision for income tax	(9,338)	23,443
Net (loss) income	(29,669)	15,758
Less: Net loss attributable to non-controlling interest	20	3,393
Net (loss) income attributable to the Partnership	$(29,649)	$ 19,151
Net (loss) income attributable to the Partnership's common unitholders (Note 16):		
Basic	$ (0.53)	$ 0.54
Diluted	$ (0.53)	$ 0.54
Weighted average number of outstanding common units:		
Basic	56,806	34,910
Diluted	56,806	34,922
Cash distribution declared per common unit(1)	$ 0.64	$ 0.19

(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 (see Note 1).

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	254	608	—	608
Distributions paid	—	(36,803)	—	(36,803)
Share-based compensation related to equity awards	—	1,154	—	1,154
Net proceeds from sale of equity interest in joint venture	—	(5,464)	50,000	44,536
Net loss	—	(29,649)	(20)	(29,669)
March 31, 2009	56,894	$1,134,304	$53,281	$1,187,585

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)

	Three months ended March 31,	
	2009	**2008**
Cash flows from operating activities:		
Net (loss) income	$ (29,669)	$ 15,758
Adjustments to reconcile net (loss) income to net cash provided by operating activities (net of acquisitions):		
Depreciation	20,943	14,525
Amortization of intangible assets	10,233	6,849
Amortization of deferred financing costs and discount	1,391	1,043
Accretion of asset retirement obligations	47	32
Amortization of deferred contract cost	78	78
Phantom unit compensation expense	2,703	1,128
Participation Plan compensation expense	—	4,271
Restricted stock compensation expense	—	75
Equity in loss (earnings) of unconsolidated affiliates	105	(1,551)
Distributions from unconsolidated affiliates	—	2,170
Unrealized loss (gain) on derivative instruments	66,918	(4,893)
Loss on disposal of property, plant and equipment	729	3
Deferred income taxes	(15,591)	12,676
Gain on sale of available for sale securities	—	(1,238)
(Gain) loss on sale of trading securities	(40)	104
Net sales of trading securities	552	2,400
Other	—	(28)
Changes in operating assets and liabilities, net of working capital acquired:		
Receivables	21,531	(19,494)
Inventories	20,634	23,299
Other current assets	1,620	38,106
Accounts payable and accrued liabilities	(6,683)	38,898
Other long-term assets	(4,073)	(11,444)
Other long-term liabilities	392	461
Net cash provided by operating activities	91,820	123,228
Cash flows from investing activities:		
Change in restricted cash	(1,125)	—
Equity method investments	(4,984)	(11,620)
Cash paid to acquire General Partnership's minority interest	—	(21,210)
Cash paid in Merger for MarkWest Hydrocarbon, Inc. stock	—	(240,513)
Proceeds from sale of available for sale securities	—	6,226
Capital expenditures	(168,942)	(74,986)
Proceeds from disposal of property, plant and equipment	—	8
Net cash flows used in investing activities	(175,051)	(342,095)
Cash flows from financing activities:		
Proceeds from long-term debt	234,700	411,501
Payments of long-term debt	(125,000)	(159,001)
Payments for debt issuance costs, deferred financing costs and registration costs	(4,323)	(18,431)
Net proceeds from sale of equity interest in joint venture	44,536	—
Exercise of stock options	—	375
Cash paid for taxes related to net settlement of share-based payment awards	(1,199)	—
APIC pool for excess tax benefits under SFAS 123R	—	717
Payment of distributions and dividends	(36,803)	(4,338)
Distributions to MarkWest Energy unitholders prior to the Merger	—	(19,651)
Net cash flows provided by financing activities	111,911	211,172
Net increase (decrease) in cash	28,680	(7,695)
Cash and cash equivalents at beginning of year	3,321	37,695
Cash and cash equivalents at end of period	$ 32,001	$ 30,000

MARKWEST ENERGY PARTNERS, L.P.

Condensed Consolidated Statements of Cash Flows (Continued)

(unaudited, in thousands)

	Three months ended March 31,	
	2009	**2008**
Supplemental disclosures of cash flow information:		
Cash paid for interest, net of amounts capitalized	$ 8,240	$ 13,049
Cash paid for income taxes	190	302
Supplemental schedule of non-cash investing and financing activities:		
Accrued property, plant and equipment	$53,445	$ 23,772
Interest capitalized on construction in progress	4,893	1,059
Property, plant and equipment asset retirement obligation	321	—
Merger step-up of fair value	—	605,182
Issuance of common units for vesting of share-based payment awards	8,683	1,997

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

MARKWEST ENERGY PARTNERS, L.P.

Notes to the Condensed Consolidated Financial Statements

(unaudited)

1. Organization and Basis of Presentation

MarkWest Energy Partners, L.P. (the "Partnership") 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 natural gas liquids, or NGLs, and the gathering and transportation of crude oil. The Partnership has extensive natural gas gathering, processing and transmission operations in the southwestern and Gulf Coast regions of the United States and is the largest natural gas processor in the Appalachian region.

On February 21, 2008, the Partnership completed the transactions contemplated by its plan of redemption and merger (the "Merger") with MarkWest Hydrocarbon, Inc. (the "Corporation" or "MarkWest Hydrocarbon") and MWEP, L.L.C., a wholly-owned subsidiary of the Partnership. The Merger was accounted for in accordance with Statement of Financial Accounting Standard ("SFAS") No. 141, *Business Combinations* ("SFAS 141") and related interpretations. The Merger was considered a downstream merger, whereby the Corporation was viewed as the surviving consolidated entity for accounting and financial purposes rather that the Partnership, which is the surviving consolidated entity for legal purposes. As such, the Merger was accounted for in the Corporation's consolidated financial statements as an acquisition of non-controlling interest using the purchase method of accounting. As a result, the historical and comparative consolidated financial statements of the surviving legal entity are those of the Corporation, the accounting acquirer, rather than those of the Partnership, the legal acquirer. Also as a result of the Merger, the Corporation owns Class A units in the Partnership which are not treated as outstanding common units in the accompanying Condensed Consolidated Balance Sheets pursuant to Accounting Research Bulletin No. 51, *Consolidated Financial Statements*.

The Partnership's unaudited condensed consolidated financial statements include all majority-owned or majority-controlled subsidiaries. In addition, MarkWest Liberty Midstream & Resources L.L.C. ("MarkWest Liberty Midstream"), a variable interest entity for which the Partnership has been determined to be the primary beneficiary, is included in the condensed consolidated financial statements (see Note 3 for further discussion of MarkWest Liberty Midstream). 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.

These condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") 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. 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. In addition to reviewing these condensed consolidated financial statements and accompanying notes, you should also consult the audited financial statements and accompanying notes included in the Partnership's December 31, 2008 Annual Report on Form 10-K. Finally, consider that results for the three months ended March 31, 2009 are not necessarily indicative of results for the full year 2009, or any other future period.

On January 1, 2009, the Partnership adopted SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements—an Amendment of ARB No. 51* ("SFAS 160"). In accordance with the requirements of SFAS 160, the Partnership has provided a new presentation on the face of the

1. Organization and Basis of Presentation (Continued)

condensed consolidated financial statements to separately classify non-controlling interests within the equity section of the Condensed Consolidated Balance Sheets and to separately report the amounts attributable to controlling and non-controlling interests in the Condensed Consolidated Statements of Operations and Condensed Consolidated Statements of Changes in Partners' Capital for all periods presented (see Note 21 for the supplemental disclosure of the changes in partners' capital for the three months ended March 31, 2008). The adoption of SFAS 160 did not impact earnings per unit attributable to the Partnership's common unitholders.

On January 1, 2009, the Partnership also adopted FSP EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* ("FSP EITF 03-6-1"). FSP EITF 03-6-1 changes the method that the Partnership uses to calculate earnings per unit and requires retrospective application. Therefore, the presentation of earnings per unit for the prior period has been changed to reflect the requirements of FSP EITF 03-6-1. See Note 2 and Note 16 for further details regarding FSP EITF 03-6-1 and the Partnership's earnings per unit calculation.

2. Recent Accounting Pronouncements

In September 2006 the Financial Accounting Standards Board ("FASB") issued SFAS No. 157, *Fair Value Measurements* ("SFAS 157"). SFAS 157 clarifies the principle that fair value should be based on the assumptions market participants would use when pricing an asset or liability and establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. SFAS 157 became effective for the Partnership's financial statements as of January 1, 2008. The initial adoption of SFAS 157 as of January 1, 2008 had an effect of a $1.1 million decrease to fair value of derivative instruments liability, a decrease to Revenue—derivative loss of $0.4 million and an increase to derivative gain related to purchased product costs of $0.7 million.

In February 2008 the FASB approved the partial deferral of SFAS 157 for non-financial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a reoccurring basis (at least annually). The provisions of SFAS 157 adopted as of January 1, 2009 did not have a material impact on the Partnership's financial statements.

In April 2009 the FASB issued Staff Position ("FSP") FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly* ("FSP FAS 157-4"). FSP FAS 157-4 provides guidance for estimating fair value in accordance with SFAS 157 when the volume and level of activity for the asset or liability have significantly decreased. Additionally, FSP FAS 157-4 provides guidance on identifying circumstances that indicate a transaction is not orderly. The FSP requires prospective application and is effective for interim reporting periods beginning after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. The Partnership has not elected early adoption and believes the implementation of FSP FAS 157-4 will not have a material impact on its financial statements.

In October 2008 the FASB issued FSP FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active* ("FSP FAS 157-3"). FSP FAS 157-3 clarifies the application of SFAS 157 as it relates to the valuation of financial assets in a market that is not active for those financial assets. FSP FAS 157-3 became effective immediately and includes those periods for

2. Recent Accounting Pronouncements (Continued)

which financial statements have not been issued. The adoption of FSP FAS 157-3 did not have a material impact on the Partnership's financial statements.

In December 2007 the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* ("SFAS 141R"). This statement replaces SFAS 141. The statement provides for how the acquirer recognizes and measures the identifiable assets acquired, liabilities assumed and any non-controlling interest in the acquiree. SFAS 141R provides for how the acquirer recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase. The statement determines what information to disclose to enable users to evaluate the nature and financial effects of the business combination. The provisions of SFAS 141R became effective for the Partnership as of January 1, 2009. The adoption of SFAS 141R did not have a material impact on the Partnership's financial statements.

In December 2007 the FASB issued SFAS 160. This statement provides that non-controlling interests in subsidiaries held by parties other than the parent be identified, labeled and presented in the statement of financial position within equity, but separate from the parent's equity. SFAS 160 states that the amount of consolidated net income attributable to the parent and to the non-controlling interest be clearly identified on the consolidated statement of income. The statement provides for consistency regarding changes in parent ownership including when a subsidiary is deconsolidated. Any retained non-controlling equity investment in the former subsidiary will be initially measured at fair value. The provisions of SFAS 160 became effective for the Partnership as of January 1, 2009. The adoption of SFAS 160 did not have a material impact on the Partnership's financial statements, except for the reclassification of non-controlling interest to partners' capital on the Condensed Consolidated Balance Sheets.

In April 2008 the FASB issued FSP FAS 142-3, *Determination of the Useful Life of Intangible Assets* ("FSP FAS 142-3"). FSP FAS 142-3 amends the factors that an entity should consider in developing renewal or extension assumptions used in determining the useful life of recognized intangible assets under SFAS 142. In determining the useful life of an acquired intangible asset, FSP FAS 142-3 removes the requirement from SFAS 142 for an entity to consider whether renewal of the intangible asset requires significant costs or material modifications to the related arrangement. FSP FAS 142-3 also replaces the previous useful life assessment criteria with a requirement that an entity consider its own experience in renewing similar arrangements. If the entity has no relevant experience, it would consider market participant assumptions regarding renewal. FSP FAS 142-3 became effective for the Partnership as of January 1, 2009 and applies only to intangible assets acquired after that date. Retroactive application to previously acquired intangible assets is prohibited. The adoption of FSP 142-3 did not have a material impact on the Partnership's financial statements.

In May 2008 the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* ("SFAS 162"). SFAS 162 provides a consistent framework for determining what accounting principles should be used when preparing U.S. GAAP financial statements. SFAS 162 is not effective for the Partnership as of March 31, 2009. The adoption of SFAS 162 is not expected to have a material impact on the Partnership's financial statements.

In June 2008 the FASB issued FSP EITF 03-6-1. FSP EITF 03-6-1 states that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid

2. Recent Accounting Pronouncements (Continued)

or unpaid) are participating securities and shall be included in the computation of earnings per unit pursuant to the two-class method as described in SFAS No. 128, *Earnings per Share*. FSP EITF 03-6-1 became effective for the Partnership beginning January 1, 2009 and requires retrospective application. The adoption of FSP EITF 03-6-1 does not have any impact on the net income reported in the Partnership's Condensed Consolidated Statements of Operations, however, the reported earnings per unit will generally be lower than the amount reported prior to adoption. See Note 16 for calculation of the Partnership's earnings per unit.

In November 2008 the Emerging Issues Task Force ("EITF") reached a consensus on Issue No. 08-6, *Equity Method Investment Accounting Considerations* ("EITF 08-6"). The consensus opinion in EITF 08-6 clarifies the accounting for certain transactions and impairment considerations involving equity method investments which were affected by the FASB issuances of SFAS 141R and SFAS 160. The transition provisions require prospective application and became effective for the Partnership on January 1, 2009. EITF 08-6 did not have a material impact on the Partnership's financial statements.

3. Variable Interest Entity

On February 27, 2009, the Partnership entered into a joint venture with M&R MWE Liberty L.L.C. ("M&R"), an affiliate of NGP Midstream & Resources, L.P. ("M&R"). 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. M&R is a private equity firm focused on investments in selected areas of the energy infrastructure and natural resources sectors. 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 and net book value of the contributed assets was approximately $109.3 million. At closing, M&R contributed cash of $50.0 million in exchange for a 40% ownership interest. The Partnership will serve as the operator of MarkWest Liberty Midstream and the employees of a wholly-owned subsidiary of the Partnership will provide the field operating and general and administrative services. A portion of the fee for providing these services is fixed. The Partnership is in the process of allocating net assets and such allocation and the value of contributed assets is subject to further adjustment.

The Partnership has determined that MarkWest Liberty Midstream is a variable interest entity primarily due to the insufficiency of equity, as defined by FASB Interpretation No. 46(R), *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51*, 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 has no debt and will be funded entirely by the Partnership and M&R.

During 2009 M&R will make additional cash contributions of $150.0 million. If MarkWest Liberty Midstream capital expenditures in 2009 exceed M&R's contributions, the Partnership would be required to fund the excess in 2009. Due to M&R's financing of the majority of 2009 capital expenditures, the

3. Variable Interest Entity (Continued)

capital contributed to MarkWest Liberty Midstream will be disproportionate to each party's respective ownership interests. Under the terms of the joint venture agreement, the Partnership anticipates making approximately $200.0 million of 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.

As the primary beneficiary of MarkWest Liberty Midstream, the Partnership consolidates the entity and, with the exception of recognizing the non-controlling interest, there is no effect on the Partnership's condensed consolidated financial statements. The Partnership has not provided any financial support that it was not contractually obligated to provide during those periods. The Partnership reflected the following amounts in its Condensed Consolidated Balance Sheet for MarkWest Liberty Midstream (in thousands):

	March 31, 2009
ASSETS	
Accounts receivable	$ 3,835
Inventories	3,525
Other current assets(1)	1,228
Property, plant and equipment, net of accumulated depreciation of $1,300	179,983
Other long-term assets	3,867
Total assets	$192,438
LIABILITIES	
Accounts payable	$ 5,434
Accrued liabilities	22,761
Total liabilities	$ 28,195

(1) Other current assets includes $1.1 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 are the property of the venture and are not available to the Partnership for any other purpose, including collateral for its secured debt (see Note 13 and Note 20). The liabilities of MarkWest Liberty Midstream do not represent additional claims against the Partnership's general assets.

3. Variable Interest Entity (Continued)

The Partnership's Liberty segment includes the results of operations of MarkWest Liberty Midstream (see Note 19). The cash flow information for MarkWest Liberty Midstream comprises substantially all of the cash flow information of non-guarantors (see Note 20).

The following table shows the net income attributable to the Partnership and transfers to the non-controlling interest for the three months ended March 31, 2009 (in thousands).

Net loss attributable to the Partnership	$(29,649)
Transfers to the non-controlling interest:	
Decrease in partners' capital for transaction costs related to sale of 40% interest in MarkWest Liberty Midstream	(5,464)
Net loss attributable to the Partnership and transfers to the non-controlling interests	$(35,113)

4. Derivative Financial Instruments

Commodity Instruments

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 over-the-counter ("OTC") market.

4. Derivative Financial Instruments (Continued)

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 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. The Partnership Credit Agreement prevents members of the participating bank group from requiring margin calls. As of March 31, 2009 approximately 8% 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 plans to meet with letters of credit. 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.

The Partnership values its derivative instruments and estimates fair value as discussed in Note 5. 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.

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

Derivative commodity contracts not designated as hedging instruments under SFAS 133 and their balance sheet location	Asset Derivatives		Liability Derivatives	
	Fair Value at March 31, 2009	Fair Value at December 31, 2008	Fair Value at March 31, 2009	Fair Value at December 31, 2008
Fair value of derivative instruments—current assets	$ 72,082	$126,949	$ —	$ —
Fair value of derivative instruments—long-term assets	51,725	55,389	—	—
Fair value of derivative instruments—current liabilities	—	—	(37,960)	(37,633)
Fair value of derivative instruments—long-term liabilities	—	—	(22,861)	(14,801)
Total	$123,807	$182,338	$(60,821)	$(52,434)

4. Derivative Financial Instruments (Continued)

Derivative commodity contracts not designated as hedging instruments under SFAS 133 and the location of gain or (loss) recognized in income	Three months ended March 31, 2009	Three months ended March 31, 2008
Revenue: Derivative gain (loss)		
Realized gain (loss)	$ 61,114	$(18,959)
Unrealized loss	(52,810)	(27,291)
Total Revenue: derivative gain (loss)	8,304	(46,250)
Derivative (loss) gain related to purchased product costs		
Realized loss	(16,250)	(144)
Unrealized (loss) gain	(13,263)	32,141
Total derivative (loss) gain related to purchased product costs	(29,513)	31,997
Derivative gain related to facility expenses		
Unrealized gain	371	43
Total	$(20,838)	$(14,210)

The change in market value of contracts, realized and unrealized, is recorded as a component of revenue, purchased product costs or facility expenses. 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.

At March 31, 2009, the fair value of the Partnership's derivative instruments is inclusive of premium payments of $12.2 million, net of amortization. The Partnership amortizes the premium payments over the effective term of the underlying derivative option contracts through realized loss. For the three months ended March 31, 2009 and 2008, the Realized (loss) gain—revenue includes amortization of premium payments of $1.2 million and $0.1 million, respectively.

Contingent Features

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 instruments with a credit risk related contingent feature that is in a liability position at March 31, 2009 is $5.2 million; however, for all outstanding transactions the Partnership has a net asset position of $10.5 million. If the credit risk contingent feature was triggered as of March 31, 2009, the Partnership would not be

4. Derivative Financial Instruments (Continued)

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.

Outstanding Commodity Forward 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 at March 31, 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	$12,711
2010 (Apr—Dec)	1,297	66.48	74.49	2,027

WTI Crude Puts	Volumes (Bbl/d)	WAVG Floor (Per Bbl)	Fair Value (in thousands)
2009	2,375	$ 80.00	$ 16,925
2010	1,191	80.00	9,155
2011	1,818	80.00	13,123

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)	Fair Value (in thousands)
2009	1,479	$119.48	$ 25,723
2010	1,549	61.77	(103)
2011	535	68.20	105
2012	529	70.30	(10)

Natural Gas Swaps	Volumes (MMBtu/d)	WAVG Price (Per MMBtu)	Fair Value (in thousands)
2009	9,942	$ 8.36	$(13,347)

The following tables provide information on the volume of the Partnership's taxable subsidiary's derivative activity for positions related to keep-whole price risk at March 31, 2009, including the WAVG:

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)	Fair Value (in thousands)
2009	3,070	$ 69.38	$ 10,703
2010	2,428	70.25	6,886
2011	3,027	87.66	21,238
2012 (Jan)	2,142	91.50	1,385

4. Derivative Financial Instruments (Continued)

Natural Gas Swaps	Volumes (MMBtu/d)	WAVG Price (Per MMBtu)	Fair Value (in thousands)
2009	20,976	$ 8.15	$(21,051)
2010	10,806	8.41	(9,128)
2011	14,662	8.88	(11,086)

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. Under SFAS 133, the value of this contract is marked based on an index price through purchased product costs. As of March 31, 2009, the estimated fair value of this contract was $(2.0) 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. Under SFAS 133, the value of the derivative component of this contract is marked to market through facility expense. As of March 31, 2009, the estimated fair value of this contract was $(0.3) million.

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

5. Fair Value

Fair Value Measurement

The Partnership adopted SFAS 157 on January 1, 2008. SFAS 157 clarifies the principle that fair value should be based on the assumptions market participants would use when pricing an asset or liability and establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. SFAS 157 applies to all fair value measurements however the FASB deferred the effective date for certain nonfinancial assets and liabilities until January 1, 2009 (see Note 2).

Valuation Hierarchy

Following is a description of the valuation methodologies the Partnership used for instruments measured at fair value, as well as the general classification of such instruments pursuant to the valuation hierarchy. The three levels in the valuation hierarchy are defined as follows:

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

5. Fair Value (Continued)

Commodity Derivative Transactions

The Partnership utilizes a combination of fixed-price forward contracts, fixed-for-floating price swaps and options available in the OTC market. The Partnership's derivative positions are valued using corroborated market data and internally developed models when observable market data is not available. Crude oil and natural gas swaps are considered Level 2 transactions as the pricing methodology include quoted prices for similar assets and liabilities and the Partnership can determine the prices are observable and do not contain Level 3 inputs that are significant to the measurement. All NGL transactions and crude oil options have significant unobservable market parameters and are normally traded less actively and therefore are classified within Level 3 of the valuation hierarchy. Due to limited liquidity and trading activity, models interpolate pricing curves within a range where broker quotes are not available, remove outlying quotes and adjust for seasonality.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while the Partnership believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at March 31, 2009.

The following table presents the financial instruments carried at fair value as of March 31, 2009 and December 31, 2008 and by SFAS 157 valuation hierarchy (as described above, in thousands):

	Assets		Liabilities
March 31, 2009	**Trading Securities**	**Derivatives**	**Derivatives**
Quoted prices in active markets for identical assets (Level 1)	$—	$ —	$ —
Significant other observable inputs (Level 2)	—	67,445	(56,131)
Significant unobservable inputs (Level 3)	—	56,362	(4,690)
Total carrying value in consolidated balance sheet	$—	$123,807	$(60,821)

	Assets		Liabilities
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 consolidated balance sheet	$512	$182,338	$(52,434)

Changes in Level 3 fair value measurements

The tables below include a rollforward of the balance sheet amounts for the three months ended March 31, 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). When a determination is made to classify a financial instrument within Level 3 of the valuation hierarchy, the determination 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,

5. Fair Value (Continued)

observable inputs (that is, inputs that are actively quoted and can be validated to external sources); accordingly, the gains and losses in the table below include changes in fair value due in part to observable inputs that are part of the valuation methodology. Level 3 includes all NGL transactions and crude oil options as they have significant unobservable market parameters and are normally traded less actively. For the period ended March 31, 2008 the Partnership considered options to be Level 2. After further consideration, options are considered Level 3 due to significant unobservable inputs. Therefore, the rollforward presented below for the three months ended March 31, 2009 includes options.

For the Three Months Ended March 31, 2009	Trading Securities	Derivatives (net)
Fair Value January 1, 2009	$ 512	$ 72,456
Total gain or loss (realized and unrealized) included in earnings(a)(b)	40	(817)
Purchases, sales, issuances and settlements (net)	(552)	(19,967)
Transfers in or out of Level 3 (net)	—	—
Fair Value March 31, 2009	$ —	$ 51,672
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at March 31, 2009(a)	$ —	$ (7,310)

For the Three Months Ended March 31, 2008	Trading Securities	Derivatives (net)
Fair Value January 1, 2008	$ 3,674	$(84,367)
Total gain or loss (realized and unrealized) included in earnings(a)(b)	(76)	(11,986)
Purchases, sales, issuances and settlements (net)	(2,400)	32,203
Transfers in or out of Level 3 (net)	—	—
Fair Value March 31, 2008	$ 1,198	$(64,150)
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at March 31, 2008(a)	$ —	$ 3,776

(a) Gains and losses on derivative positions classified as Level 3 are recorded in *Derivative gain (loss)*, a component of *Total revenue*.

(b) Gains and losses on trading securities are realized and recorded in *Miscellaneous expense*.

Assets and liabilities measured at fair value on a nonrecurring basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis; that is, the instruments are not measured at fair value on an ongoing basis but are subject to fair value

5. Fair Value (Continued)

adjustments in certain circumstances. As of March 31, 2009, there were not any assets or liabilities to be measured at fair value on a nonrecurring basis.

6. Marketable Securities

As of December 31, 2008, the Partnership held certain auction rate securities that were classified and accounted for as trading securities in accordance with SFAS 115, *Accounting for Certain Investments in Debt and Equity Securities*. The $0.5 million recorded value of these securities at December 31, 2008 consisted of an original cost basis of $1.2 million and an other-than-temporary impairment of $0.7 million. Because the market mechanism normally used to liquidate the trading securities was no longer operating efficiently and it was not known if the market mechanism would become efficient within the next year, the balance of these securities is included in *Other long-term assets* as of December 31, 2008 in the accompanying Condensed Consolidated Balance Sheets. During the first quarter of 2009, the Partnership sold these securities for approximately $0.6 million and recognized a gain of less than $0.1 million. This gain is included in *Miscellaneous expense* in the accompanying Condensed Consolidated Statements of Operations.

7. Receivables

Receivables consist of the following (in thousands):

	March 31, 2009	December 31, 2008
Trade, net	$68,600	$ 88,370
Other(1)	11,718	13,479
Total receivables	$80,318	$101,849

(1) Related primarily to amounts due from the settlement of derivative positions.

8. Inventories

Inventories consist of the following (in thousands):

	March 31, 2009	December 31, 2008
Natural gas and natural gas liquids	$ 6,329	$29,171
Spare parts	7,179	2,385
Total inventories	$13,508	$31,556

9. Property, Plant and Equipment

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

	March 31, 2009	December 31, 2008
Natural gas gathering facilities, pipelines and gas processing plants	$1,325,592	$1,206,584
Fractionation and storage facilities	28,081	24,498
Crude oil pipelines	16,807	16,104
NGL transportation facilities	11,887	10,888
Land, building, office equipment and other	109,123	87,842
Construction in progress	325,568	304,776
Property, plant and equipment	1,817,058	1,650,692
Less: accumulated depreciation	(99,995)	(81,167)
Total property, plant and equipment, net	$1,717,063	$1,569,525

The Partnership capitalizes interest on major projects during construction. For the three months ended March 31, 2009 and 2008, the Partnership capitalized interest, including deferred finance costs, of $4.9 million and $1.1 million, respectively.

10. Goodwill and Intangible Assets

Goodwill. The Partnership's $9.4 million goodwill balance as of March 31, 2009 and December 31, 2008 consisted of $3.9 million allocated to the Northeast segment and $5.5 million allocated to the Southwest segment. In accordance with SFAS 142, 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. Due to the fact that the Partnership's market capitalization has remained significantly less than the book value of its net assets, management completed a goodwill impairment analysis as of March 31, 2009 and determined that no impairment had occurred.

Intangible Assets. The Partnership's intangible assets, net of accumulated amortization, are comprised of customer contracts and relationships, as follows (in thousands):

Segment	March 31, 2009	December 31, 2008
Southwest	$377,184	$382,836
Northeast	60,983	62,697
Gulf Coast	247,517	250,384
Total	$685,684	$695,917

Amortization expense related to the intangible assets was $10.2 million and $6.8 million for the three months ended March 31, 2009 and 2008, respectively.

11. Investments in Unconsolidated Affiliates

The Partnership applies the equity method of accounting for its 50% non-operating interest in Starfish Pipeline Company, L.L.C. (“Starfish”) and its 40% non-operating interest in Centrahoma Processing L.L.C. (“Centrahoma”).

On March 1, 2008, the Partnership acquired a 20% interest in Centrahoma for $11.6 million. On May 9, 2008, the Partnership exercised its option to acquire an additional 20% interest in Centrahoma for $12.0 million including a capital call. The purchase increased the Partnership’s non-operating interest to 40%. Centrahoma owns certain processing plants in the Arkoma Basin. In addition, the Partnership signed agreements to dedicate our processing rights in certain acreage in the Woodford Shale area to Centrahoma through March 1, 2018. The Partnership’s share of Centrahoma’s net (loss) income was $(0.5) million and less than $0.1 million for the three months ended March 31, 2009 and 2008, respectively. Summarized financial information for 100% of Centrahoma is as follows (unaudited, in thousands):

	Three months ended March 31, 2009	Three months ended March 31, 2008
Revenues	$ 1,719	$403
Operating (loss) income	(104)	184
Net (loss) income	(1,181)	184

In September 2008, Hurricane Ike caused wind and water damage to oil and gas assets in the Gulf of Mexico and Gulf Coast regions, including damage to several onshore and offshore facilities of Starfish. Due to the damage in the region, the operations of Starfish were partially curtailed during the first quarter resulting in a decrease in the Partnership’s *Earnings from unconsolidated affiliates* in the accompanying Condensed Consolidated Statements of Operations. In addition to the $5.0 million contributed in 2008 to fund the repairs resulting from the hurricane, the Partnership has contributed $3.8 million in the first quarter of 2009 and may receive additional capital calls. The Partnership’s share of Starfish’s net income was $0.4 million and $1.5 million for the three months ended March 31, 2009 and 2008, respectively. The Partnership expects to file insurance claims to recover a portion of the losses associated with the business interruption and the costs associated with damage repairs. Summarized financial information for 100% of Starfish is as follows (unaudited, in thousands):

	Three months ended March 31, 2009	Three months ended March 31, 2008
Revenues	$6,379	$7,721
Operating income	3,410	2,870
Net income	820	3,173

11. Investments in Unconsolidated Affiliates (Continued)

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

	March 31, 2009	December 31, 2008
Investment in Starfish	$21,360	$17,181
Investment in Centrahoma	29,611	28,911
Total investment in unconsolidated affiliates	$50,971	$46,092

12. Asset Retirement Obligation

A reconciliation of the Partnership's asset retirement obligation from December 31, 2008 to March 31, 2009 is as follows (in thousands):

Asset retirement obligation as of December 31, 2008	$1,773
Liabilities incurred	321
Accretion expense	47
Asset retirement obligation as of March 31, 2009	$2,141

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

13. Long-Term Debt

Debt is summarized below (in thousands):

	March 31, 2009	December 31, 2008
Credit Facility		
Revolver facility, 4.55% and 2.51% interest at March 31, 2009 and December 31, 2008, respectively, due February 2012	$ 294,400	$ 184,700
Senior Notes		
Senior Notes, 6.875% interest, net of discount of $9,272 and $9,676, respectively, due November 2014	215,728	215,324
Senior Notes, 8.5% interest, net of discount of $852 and $882, respectively, due July 2016	274,148	274,118
Senior Notes, 8.75% interest, net of discount of $1,146 and $1,177, respectively, due April 2018	498,854	498,823
Total long-term debt	$1,283,130	$1,172,965

13. 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 will now be repayable by 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 will continue to bear interest at a variable interest rate, plus basis points. The variable interest rate typically is based on the London Inter Bank Offering Rate ("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. The write-off 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 we are 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. As of March 31, 2009, the Partnership had $294.4 million of borrowings outstanding and $31.4 million of letters of credit outstanding under the revolving credit facility, leaving approximately $109.8 million available for borrowing.

Senior Notes

At March 31, 2009, MarkWest Energy Partners, L.P. in conjunction with its wholly-owned subsidiary MarkWest Energy Finance Corporation (the "Issuers"), had three series of senior notes outstanding: $225.0 million aggregate principal maturing in November 2014 (the "2014 Senior Notes"), $275.0 million aggregate principal due in July 2016 (the "2016 Senior Notes"), and $500.0 million aggregate principal maturing in 2018 (the "2018 Senior Notes" and all together with the 2014 Senior Notes and 2016 Senior Notes, the "Senior Notes"). The estimated fair value of the Senior Notes was approximately $696.4 million and $627.1 million at March 31, 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

13. Long-Term Debt (Continued)

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.

14. Income Taxes

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

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

The provision for income tax benefit totaled $9.3 million for the three months ended March 31, 2009, resulting in an effective tax rate of 23.9%. The 2009 estimated annual effective income tax rate varies from the statutory rate mainly due to treatment of the Class A units and book deductions permanently in excess of the tax deduction for equity compensation expense.

The provision for income tax expense totaled $23.4 million for the three months ended March 31, 2008, resulting in an effective tax rate of 59.8%. The 2008 estimated annual effective income tax rate varies from the statutory rate mainly due to treatment of the Class A units as discussed above and the write-off of certain deferred tax assets that as an indirect result of the Merger will no longer be realized.

14. Income Taxes (Continued)

A reconciliation of the provision for income tax and the amount computed by applying the federal statutory rate of 35% to the (loss) income before income taxes for the three months ended March 31, 2009 and 2008 is as follows (in thousands):

	Three months ended March 31, 2009			
	Corporation	Partnership	Eliminations	Consolidated
Loss before provision for income tax	$(26,817)	$(7,661)	$(4,529)	$(39,007)
Federal statutory rate	35%	0%	0%	
Federal income tax at statutory rate	$ (9,386)	$ —	$ —	$ (9,386)
Permanent items	13	—	—	13
State income taxes net of federal benefit	(658)	(48)	—	(706)
Provision on income from Class A units	3	—	—	3
Excess book deduction related to equity compensation	735	3	—	738
Provision for income tax	$ (9,293)	$ (45)	$ —	$ (9,338)

	Three months ended March 31, 2008			
	Corporation	Partnership	Eliminations	Consolidated
Income before provision for income tax	$ 40,392	$ 4,901	$(6,092)	$ 39,201
Federal statutory rate	35%	0%	0%	
Federal income tax at statutory rate	$ 14,138	$ —	$ —	$ 14,138
Permanent items	30	—	—	30
State income taxes net of federal benefit	1,029	63	—	1,092
Provision on income from Class A units	917	—	—	917
Write-off of deferred income tax assets	7,471	—	—	7,471
Other	(205)	—	—	(205)
Provision for income tax	$ 23,380	$ 63	$ —	$ 23,443

15. Incentive Compensation Plans

As of March 31, 2009, the Partnership had four share-based compensation plans which are administered by the Compensation Committee of the General Partner's board of directors ("Compensation Committee"). Compensation expense is recognized under SFAS No. 123R, *Share-Based Payment* ("SFAS 123R"). For further detail on these plans, see Note 17 in the Notes to

15. Incentive Compensation Plans (Continued)

Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2008.

Share-based compensation plan	Plan qualification under SFAS 123R	Further awards authorized for issuance under plan
2008 Long-Term Incentive Plan ("2008 LTIP")	Equity awards	Yes
2006 Hydrocarbon Stock Incentive Plan ("2006 Hydrocarbon Plan")	Equity awards	No
Long-Term Incentive Plan ("2002 LTIP")	Liability awards	No
1996 Hydrocarbon Stock Incentive Plan ("1996 Hydrocarbon Plan")	Equity awards	No

Compensation Expense

Compensation expense under the share-based compensation plans has been recorded as either *Selling, general and administrative expenses* or *Facility expenses* in the accompanying Condensed Consolidated Statements of Operations. Total compensation expense recorded for share-based pay arrangements is as follows (in thousands):

	Three months ended March 31,	
	2009	2008
Phantom units	$2,703	$1,998
Distribution equivalent rights	338	97
Restricted stock	—	75
General partner interests under Participation Plan	—	5,196
Total compensation expense	$3,041	$7,366

The interests in the Partnership's General Partner sold by the Corporation to certain directors and employees were referred to as the Participation Plan. The Participation Plan was considered a compensatory arrangement. 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 March 31, 2009, total compensation expense not yet recognized related to the unvested awards under the 2008 LTIP, 2006 Hydrocarbon Plan and 1996 Hydrocarbon Plan was approximately $19.0 million, with a weighted average remaining vesting period of approximately 1.8 years. Total compensation expense not yet recognized related to unvested awards under the 2002 LTIP was approximately $0.4 million, with a weighted-average remaining vesting period of approximately 1.2 years. The actual compensation expense recognized for awards under the 2002 LTIP may differ as they qualify as liability awards under SFAS 123R, which are affected by changes in fair value.

15. Incentive Compensation Plans (Continued)

2008 LTIP, 2006 Hydrocarbon Plan and 1996 Hydrocarbon Plan

As of March 31, 2009, the phantom units outstanding under the 2008 LTIP include 478,950 phantom units granted to senior executives and other key employees which contain performance vesting criteria ("performance units"). The performance units outstanding include 154,500 units granted during the three months ended March 31, 2009. Vesting of the performance units occurs if the Partnership achieves established performance goals determined by the Compensation Committee. In accordance with the provisions of SFAS 123R, management will conduct a quantitative analysis on an ongoing basis to assess the probability of meeting the established performance goals and will record compensation expense as required. Compensation expense recorded for the performance units expected to vest was approximately $0.3 million for both of the three months ended March 31, 2009 and 2008.

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	435,035	8.39
Vested(1)	(284,503)	31.86
Forfeited	(141)	31.79
Unvested at March 31, 2009	1,059,697	22.17

(1) Includes 139,050 performance units.

	Three months ended March 31, 2009	Three months ended March 31, 2008
	(in thousands)	
Total grant-date fair value of phantom units granted during the period	$3,649	$28,391
Total fair value of phantom units vested during the period and total intrinsic value of phantom units settled during the period	$9,064	$ 125

As part of a net settlement option, employees may elect to surrender a certain number of phantom units upon vesting, and in exchange, the Partnership will assume the income tax withholding obligations related to the vesting. During the three months ended March 31, 2009 and 2008, the Partnership was required to pay approximately $1.0 million and zero, respectively, for income tax withholdings related to the vesting of phantom unit awards. Other than the amounts paid related to the net settlement option, there were no cash settlements and the Partnership received no proceeds for issuing phantom units during the three months ended March 31, 2009.

15. Incentive Compensation Plans (Continued)

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
Granted	—	—
Vested	(65,655)	29.80
Forfeited	(963)	34.00
Unvested at March 31, 2009	79,309	32.78

	Three months ended March 31, 2009	Three months ended March 31, 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	$818	$1,872

As part of a net settlement option, employees may elect to surrender a certain number of phantom units upon vesting, and in exchange, the Partnership will assume the income tax withholding obligations related to the vesting. During the three months ended March 31, 2009 and 2008, the Partnership was required to pay approximately $0.2 million and zero, respectively, for income tax withholdings related to the vesting of phantom unit awards. Other than the amounts paid related to the net settlement option, there were no cash settlements and the Partnership received no proceeds for issuing phantom units during the three months ended March 31, 2009.

MarkWest Hydrocarbon Stock Options

On or before February 21, 2008, the remaining 51,509 MarkWest Hydrocarbon stock options outstanding were exercised or deemed exercised. The following summarizes the impact of the Corporation's stock options for the three months ended March 31, 2008 (in thousands):

Options exercised, cashless	1
Shares issued, cashless	1
Options exercised, cash	50
Shares issued, cash	50

For the three months ended March 31, 2008, the Corporation received $0.4 million for the exercise of stock options. The intrinsic value of the options exercised during the three months ended March 31, 2008 was $2.9 million.

16. Earnings Per Unit

As a result of the adoption of FSP EITF 03-6-1 on January 1, 2009, 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 SFAS No. 128, *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 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) per common unit, for the three months ended March 31, 2009 and 2008, and the weighted-average units used to compute diluted net income (loss) per unit (in thousands, except per unit data):

	Three months ended March 31,	
	2009	2008
Net (loss) income attributable to the Partnership	$(29,649)	$19,151
Less: Income allocable to phantom units	390	195
Income available for common unitholders	$(30,039)	$18,956
Weighted average common units outstanding—basic	56,806	34,910
Effect of dilutive instruments(1)	—	12
Weighted average common units outstanding—diluted	56,806	34,922
Net (loss) income attributable to the Partnership's common unitholders		
Basic	$ (0.53)	$ 0.54
Diluted	$ (0.53)	$ 0.54

(1) Phantom units are considered to be participating securities under EITF 03-6-1. As a result, the Partnership had no potential common units outstanding during the three months ended March 31, 2009. The dilutive instruments for the three months ended March 31, 2008 include MarkWest Hydrocarbon stock options outstanding prior to the Merger.

17. Distributions to Unitholders

On April 23, 2009, the Partnership declared a cash distribution of $0.64 per common unit for the quarter ended March 31, 2009. The distribution will be paid on May 15, 2009, to unitholders of record as of May 4, 2009. The ex-dividend date was April 30, 2009.

On January 27, 2009, the Partnership declared a cash distribution of $0.64 per common unit for the quarter ended December 31, 2008. The distribution was paid on February 13, 2009, to unitholders of record as of February 6, 2009. The ex-dividend date was February 4, 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.

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 a motion to dismiss one of the counts of violations, 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. A hearing has been tentatively set for September 14, 2009, and a new schedule has been created for OPS to provide a complete administrative record, for the parties to prepare briefs for the motion to dismiss and for the OPS to rule upon the motion to dismiss prior to the hearing. MarkWest believes it has viable defenses to the remaining counts and will vigorously defend all applicable assertions of violations at the hearing.

Related to the above referenced 2004 pipeline explosion and fire incident, MarkWest Hydrocarbon and the Partnership have filed an action captioned *MarkWest Hydrocarbon, Inc., et al. v. Liberty Mutual Ins. Co., et al.* (District Court, Arapahoe County, Colorado, Case No. 05CV3953 filed August 12, 2005), as removed to the U.S. District Court for the District of Colorado, (Civil Action No. 1:05-CV-1948, on October 7, 2005) against their All-Risks Property and Business Interruption insurance carriers as a

18. Commitments and Contingencies (Continued)

result of the insurance companies' refusal to honor their insurance coverage obligation to pay the Partnership for certain costs related to the pipeline incident. The Partnership did not provide for a receivable for any of the claims in this action because of the uncertainty as to whether and how much it would ultimately recover under the policies. On April 23, 2008, the U.S. District Court issued an order granting Defendant insurance companies' motion for summary judgment. The Partnership filed an appeal of this Order to the 10th Circuit Court of Appeals (Case No. 08-1186), but the 10th Circuit Court, after oral arguments, denied MarkWest's appeal on March 9, 2009.

With regard to the Partnership's Javelina facility, MarkWest Javelina is a party with numerous other defendants to several lawsuits brought by various plaintiffs who had residences or businesses located near the Corpus Christi industrial area, an area which included the Javelina gas processing plant, and several petroleum, petrochemical and metal processing and refining operations. These suits, *Victor Huff v. ASARCO Incorporated, et al*. (Cause No. 98-01057-F, 214th Judicial Dist. Ct., County of Nueces, Texas, original petition filed in March 3, 1998); *Jason and Dianne Gutierrez, individually and as representative of the estate of Sarina Galan Gutierrez* (Cause No. 05-2470-A, 28th Judicial District); and *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), set forth claims for wrongful death, personal injury or property damage, harm to business operations and nuisance type claims, allegedly incurred as a result of operations and emissions from the various industrial operations in the area or from products Defendants allegedly manufactured, processed, used, or distributed. Settlements have been reached with the parties in the *Gutierrez* and *Huff* actions for immaterial amounts. The remaining action, *Valasquez, et al. v. Occidental Chemical Corp.*, 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.

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 geographical 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 consisting primarily of our 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

19. Segment Information (Continued)

aggregation criteria under SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information*, 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 in the future, management believes that transparency to the Liberty segment will provide useful information to investors.

The Partnership prepares segment information in accordance with GAAP, except that certain items below *(Loss) income 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 tables below present information about operating income and capital expenditures for the reported segments for the three months ended March 31, 2009 and 2008 (in thousands).

Three months ended March 31, 2009:	Southwest	Northeast	Liberty	Gulf Coast	Total
Revenue	$104,606	$61,592	$ 6,656	$10,513	$183,367
Operating expenses:					
Purchased product costs	50,534	50,954	826	—	102,314
Facility expenses	18,125	5,165	2,539	5,271	31,100
Operating income before items not allocated to segments	$ 35,947	$ 5,473	$ 3,291	$ 5,242	$ 49,953
Capital expenditures	$ 84,429	$13,224	$50,290	$20,877	$168,820
Capital expenditures not allocated to segments					122
Total capital expenditures					$168,942

Three months ended March 31, 2008:	Southwest	Northeast	Liberty(1)	Gulf Coast	Total
Revenue	$158,076	$103,804	$—	$23,162	$285,042
Operating expenses:					
Purchased product costs	92,638	62,297	—	—	154,935
Facility expenses	13,875	4,782	—	3,827	22,484
Operating income before items not allocated to segments	$ 51,563	$ 36,725	$—	$19,335	$107,623
Capital expenditures	$ 50,862	$ 3,614	$—	$19,131	$ 73,607
Capital expenditures not allocated to segments					1,379
Total capital expenditures					$ 74,986

(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 three months ended March 31, 2009 and 2008 (in thousands).

	Three months ended March 31,	
	2009	2008
Total segment revenue	$183,367	$285,042
Derivative gain (loss) not allocated to segments	8,304	(46,250)
Total revenue	$191,671	$238,792
Operating income before items not allocated to segments	$ 49,953	$107,623
Derivative loss not allocated to segments	(20,838)	(14,210)
Compensation expense included in facility expenses not allocated to segments	(344)	(182)
Selling, general and administrative expenses	(15,927)	(22,461)
Depreciation	(20,943)	(14,525)
Amortization of intangible assets	(10,233)	(6,849)
Loss on disposal of property, plant and equipment	(729)	(3)
Accretion of asset retirement obligations	(47)	(32)
(Loss) income from operations	(19,108)	49,361
(Loss) earnings from unconsolidated affiliates	(105)	1,551
Interest income	41	514
Interest expense	(17,782)	(11,149)
Amortization of deferred financing costs and discount (a component of interest expense)	(1,391)	(1,043)
Miscellaneous expense	(662)	(33)
(Loss) income before provision for income tax	$(39,007)	$ 39,201

19. Segment Information (Continued)

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

As of March 31, 2009:	Southwest	Northeast	Liberty	Gulf Coast	Total
Total segment assets	$1,546,771	$212,185	$195,451	$552,438	$2,506,845
Assets not allocated to segments:					
Certain cash and cash equivalents					27,180
Fair value of derivatives					123,807
Investment in unconsolidated affiliates					50,971
Other(1)					43,241
					$2,752,044

(1) Includes corporate fixed assets, income tax receivable and other corporate assets not allocated to segments.

As of December 31, 2008:	Southwest	Northeast	Liberty	Gulf Coast	Total
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 derivatives					182,338
Investment in unconsolidated affiliates					46,092
Other(1)					47,591
					$2,673,054

(1) Includes corporate fixed assets, 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 March 31, 2009, the Partnership's obligations under the outstanding Senior Notes (see Note 13) 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 February 2009, following the closing of the joint venture with M&R (see Note 3), MarkWest Liberty Midstream 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 and for the three months ended March 31, 2009 is as follows (in thousands):

Condensed Consolidating Balance Sheet

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ —	$ 28,429	$ 3,424	$ 148	$ 32,001
Receivables, net of allowances	33	76,126	4,159	—	80,318
Intercompany receivables	1,730,215	251,596	2,028	(1,983,839)	—
Fair value of derivative instruments	—	72,082	—	—	72,082
Other current assets	959	19,049	4,753	—	24,761
Total current assets	1,731,207	447,282	14,364	(1,983,691)	209,162
Total property, plant and equipment, net	2,101	1,528,989	186,490	(517)	1,717,063
Other long-term assets:					
Investment in unconsolidated affiliates	—	50,971	—	—	50,971
Investment in consolidated affiliates	510,320	114,316	—	(624,636)	—
Intangibles, net of accumulated amortization	—	684,350	1,334	—	685,684
Fair value of derivative instruments	—	51,725	—	—	51,725
Intercompany notes receivable	203,315	—	—	(203,315)	—
Other long-term assets	19,930	13,642	3,867	—	37,439
Total other long-term assets	733,565	915,004	5,201	(827,951)	825,819
Total assets	$2,466,873	$2,891,275	$206,055	$(2,812,159)	$2,752,044
LIABILITIES AND PARTNERS' CAPITAL					
Current liabilities:					
Accounts payable	$ 347	$ 48,989	$ 5,515	$ —	$ 54,851
Intercompany payables	4,104	1,969,457	10,130	(1,983,691)	—
Accrued liabilities	40,069	61,582	22,813	—	124,464
Fair value of derivative instruments	—	37,960	—	—	37,960
Other current liabilities	72	2,610	—	—	2,682
Total current liabilities	44,592	2,120,598	38,458	(1,983,691)	219,957
Intercompany notes payable	—	203,315	—	(203,315)	—
Fair value of derivative instruments	—	22,861	—	—	22,861
Long-term debt, net of discounts	1,283,130	—	—	—	1,283,130
Other long-term liabilities	4,330	34,181	—	—	38,511
Partners' Capital:					
MarkWest Energy Partners, L.P. partners' capital	1,134,821	510,320	167,597	(678,434)	1,134,304
Non-controlling interest in consolidated subsidiaries	—	—	—	53,281	53,281
Total partners' capital	1,134,821	510,320	167,597	(625,153)	1,187,585
Total liabilities and partners' capital	$2,466,873	$2,891,275	$206,055	$(2,812,159)	$2,752,044

20. Supplemental Condensed Consolidating Financial Information (Continued)

Condensed Consolidating Statement of Operations

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue	$ —	$188,844	$2,827	$ —	$191,671
Operating expenses:					
Purchased product costs	—	130,989	838	—	131,827
Facility expenses	—	29,696	1,377	—	31,073
Selling, general and administrative expenses	11,810	4,397	161	(441)	15,927
Depreciation and amortization	143	30,473	560	—	31,176
Other operating expenses	—	776	—	—	776
Total operating expenses	11,953	196,331	2,936	(441)	210,779
(Loss) income from operations	(11,953)	(7,487)	(109)	441	(19,108)
Earnings from consolidated affiliates	(3,593)	(76)	—	3,669	—
Other income (expense)	(13,631)	(5,323)	13	(958)	(19,899)
Net (loss) income before provision for income tax	(29,177)	(12,886)	(96)	3,152	(39,007)
Provision for income tax benefit	(45)	(9,293)	—	—	(9,338)
Net (loss) income	(29,132)	(3,593)	(96)	3,152	(29,669)
Less: Net loss attributable to non-controlling interest	—	—	—	20	20
Net (loss) income attributable to the Partnership	$(29,132)	$ (3,593)	$ (96)	$3,172	$(29,649)

Condensed Consolidating Statement of Cash Flows

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net cash (used in) provided by operating activities	$ (11,096)	$ 98,517	$ 4,916	$ (517)	$ 91,820
Cash flows from investing activities:					
Change in restricted cash	—	—	(1,125)	—	(1,125)
Equity investments	(14,400)	(4,984)	—	14,400	(4,984)
Distributions from consolidated affiliates	—	36,267	—	(36,267)	—
Collection of notes receivable	28,085	—	—	(28,085)	—
Capital expenditures	(294)	(143,685)	(25,480)	517	(168,942)
Net cash flows used in investing activities	13,391	(112,402)	(26,605)	(49,435)	(175,051)
Cash flows from financing activities:					
Proceeds from long-term debt	234,700	—	—	—	234,700
Payments of long-term debt	(125,000)	(28,085)	—	28,085	(125,000)
Payments for debt issuance costs, deferred financing costs and registration costs	(4,323)	—	—	—	(4,323)
Contributed capital, net of transaction fees	(5,464)	14,400	50,000	(14,400)	44,536
Cash paid for taxes related to net settlement of share-based payment awards	(1,199)	—	—	—	(1,199)
Payment of distributions	(36,803)	—	(36,267)	36,267	(36,803)
Intercompany advances, net	(64,206)	55,999	8,059	148	—
Net cash flows provided by financing activities	(2,295)	42,314	21,792	50,100	111,911
Net increase in cash	—	28,429	103	148	28,680
Cash and cash equivalents at beginning of year	—	—	3,321	—	3,321
Cash and cash equivalents at end of period	$ —	$ 28,429	$ 3,424	$ 148	$ 32,001

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 three months ended March 31, 2008.

	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
Dividends paid	—	(4,338)	—	—	(4,338)
Distributions to minority interest holders	—	—	—	(19,651)	(19,651)
Share based compensation related to equity awards	—	1,705	—	—	1,705
APIC pool for excess tax benefits under SFAS 123R	—	717	—	—	717
Other	—	—	—	758	758
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 minority interest of MarkWest Energy Partners, L.P.	34,474	1,095,917	—	(502,297)	593,620
Net income (loss)	—	19,151	—	(3,393)	15,758
Realized loss on marketable securities	—	—	(928)	—	(928)
March 31, 2008	50,876	$ 941,555	$ —	$ —	$ 941,555

On February 21, 2008, the Partnership completed the transactions contemplated by its plan of redemption and merger with the Corporation and MWEP, L.L.C., a wholly-owned subsidiary of the Partnership. Under the Merger, the shareholders of the Corporation exchanged each share of Corporation common stock for consideration equal to 1.9051 Partnership common units. The Merger was accounted for in accordance with SFAS 141 and related interpretations. The Merger was considered a downstream merger, whereby the Corporation was viewed as the surviving consolidated entity for accounting and financial purposes rather than the Partnership, which is the surviving consolidated entity for legal purposes. As a result, the historical consolidated financial information presented in the table above is that of the Corporation. Therefore, the Corporation shares outstanding as of December 31, 2007 and activity through February 21, 2008 have been adjusted to the equivalent

21. Supplemental Disclosure of Changes in Partners' Capital (Continued)

number of Partnership common units based on the Exchange Ratio. The following table illustrates these conversions (shares and units in thousands):

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

In accordance with SFAS 141, the Merger was accounted for in the Corporation's consolidated financial statements as an acquisition of non-controlling interest using the purchase method of accounting. The book value of the non-controlling interest acquired in the Merger was $502.3 million. For further detail on Merger, see Note 3 in the Notes to Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2008.

22. Subsequent Events

On May 1, 2009, the Partnership entered into an agreement to form a joint venture with an affiliate of ArcLight Capital Partners, L.L.C. ("ACP"), a private equity firm focused on investments across the energy industry value chain. The joint venture entity, MarkWest Pioneer, L.L.C. ("MarkWest Pioneer") is dedicated to the construction and operation of a new 50 mile interstate pipeline, Arkoma Connector Pipeline, that will provide approximately 625,000 Dth/d of Woodford Shale takeaway capacity and interconnects with Midcontinent Express Pipeline, L.L.C. and Gulf Crossing Pipeline. Under the terms of the joint venture agreement, ACP acquired a 50% equity and voting interest in MarkWest Pioneer for $62.5 million. If the total cost of construction of the pipeline exceeds $125 million, the Partnership is required to fund the excess through additional capital contributions to the joint venture. The Partnership will serve as the operator of MarkWest Pioneer and will provide employee services through a services agreement that was entered into at the closing of the joint venture transaction.

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. 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 natural gas liquids; 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.

To better understand our business and the results of operations discussed below, it is important to have an understanding of the following factors:

- management's use of net operating margin (a non-GAAP measure, see below for reconciliation);
- the nature of the contracts from which we derive our revenue; and
- seasonality.

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

	Three months ended March 31,	
	2009	2008
Revenue	$183,367	$285,042
Purchased product costs	102,314	154,935
Net operating margin	81,053	130,107
Facility expenses	31,444	22,666
Total derivative loss	20,838	14,210
Selling, general and administrative expenses	15,927	22,461
Depreciation	20,943	14,525
Amortization of intangible assets	10,233	6,849
Loss on disposal of property, plant and equipment	729	3
Accretion of asset retirement obligations	47	32
(Loss) income from operations	$(19,108)	$ 49,361

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 these declines will continue 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.

As of March 31, 2009, our primary exposure to keep-whole contracts was limited to our Appalachian, Western Oklahoma (Arapaho), East Texas (Carthage), and Woodford processing agreements.

- As a result of the Merger with MarkWest Hydrocarbon and the acquisition of its NGL marketing business, our exposure to keep-whole contracts has increased and has resulted in an increase to our exposure to natural gas and NGL volatility in Appalachia. During the three months ended March 31, 2009, approximately 70% of the NGLs sold from Appalachia related to keep-whole contracts.
- At the inlets to the Arapaho plants, natural gas meets the downstream pipeline specification; however, we have the option of extracting NGLs when the processing margin environment is favorable. All of our gas gathering contracts in Western Oklahoma are keep-whole, but some of the contracts include additional fees to cover plant operating costs, fuel costs and shrinkage costs in a low-processing margin environment. Our keep-whole contract exposure is partially mitigated due to our ability to operate the Arapaho plants in several recovery modes.
- Approximately 12% of the gas processed in East Texas for producers was processed under keep-whole terms for the three months ended March 31, 2009.
- Approximately 40 MMcf/d of the gas in the Woodford system is rich with NGLs and is processed under keep-whole contracts. Our keep-whole contract exposure is partially mitigated by our ability to operate in several recovery modes.
- Our keep-whole exposure in all areas was partially offset by the settlement margin related to certain gathering and compression arrangements. The excess natural gas retained under these

arrangements reduced the amount of replacement natural gas purchases required to keep our producers whole on an MMBtu basis, thereby creating a partial natural hedge. We also have an active commodity risk management program in place to reduce the impacts of changing NGL and natural gas prices and our keep-whole exposure.

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 Part I, Item 3 of this report on Form 10-Q. For the three months ended March 31, 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	21%	28%	12%	39%	100%
Net operating margin	48%	23%	6%	23%	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 44%, 0% and 8%, 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

We reported a net loss of $29.6 million for the three months ended March 31, 2009, compared to net income of $19.2 million for three months ended March 31, 2008. Contributing factors to the $48.8 million change in net income for the three months ended March 31, 2009, compared to the same period in 2008 were:

- In the Northeast, Southwest and Gulf Coast segments, operating income before items not allocated to segments decreased $61.0 million for the three months ended March 31, 2009 compared to the same period in 2008. The decrease is primarily due to lower prices of natural gas and natural gas liquids in all areas.

- Depreciation and amortization increased $9.8 million for the three months ended March 31, 2009 compared to the same period in 2008. Approximately $4.4 million of the increase is due to the step-up in values for property, plant and equipment and intangible assets related to the

Merger. The remaining $5.4 million increase is due to depreciation on additional projects completed during 2008 and the first quarter of 2009.

- Interest expense increased $6.6 million for the three months ended March 31, 2009 relative to the same period in 2008. The increase is related to additional borrowings in 2008 at higher rates to fund the Merger and our capital plan.
- Derivative loss increased by $6.6 million during the three months ended March 31, 2009 compared to the same period in 2008. Unrealized loss from the mark-to-market of our derivative instruments changed by $(70.6) million while realized gain from the settlement of our derivative instruments changed by $64.0 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 4 of the accompanying Notes to the Condensed Consolidated Financial Statements included in Item 1 of this Form 10-Q.
- The provision for income tax benefit was $9.3 million for the three months ended March 31, 2009 compared to income tax expense of $23.4 million for the same period in 2008. The decrease of $32.8 million in tax expense is due primarily to the net loss reported for the first quarter of 2009. The current provision for income tax expense was $6.3 million for the three months ended March 31, 2009. Approximately $5.7 million is attributable to MarkWest Hydrocarbon, Inc. Of this amount, $5.9 million is attributable to MarkWest Hydrocarbon's ownership of Class A units, and the remaining benefit of $0.2 million is related to the Corporation's NGL marketing business. The remaining $0.6 million is related to taxes payable by the Partnership associated with the Texas Margin tax and Michigan Business Taxes.
- Selling, general and administrative expenses decreased $6.5 million for the three months ended March 31, 2009, compared to the same period in 2008 primarily due to lower expense related to share-based compensation plans. During the first quarter of 2009, no expense was recognized for the 2009 performance based phantom units as the established performance targets are not currently expected to be achieved. Additionally, the Partnership incurred $2.6 million of expenses related to the Merger during the three months ended March 31, 2008, which did not recur in 2009.

Cash Distributions

Our quarterly cash distribution of $0.64 per common unit for the quarter ended March 31, 2009 was declared on April 23, 2009.

Operating Data

	Three months ended March 31, 2009	2008	% Change
Southwest			
East Texas			
Gathering systems throughput (Mcf/d)	450,900	422,100	6.8%
NGL product sales (gallons)	48,370,000	44,483,400	8.7%
Oklahoma			
Foss Lake gathering systems throughput (Mcf/d)	92,600	103,800	(10.8)%
Stiles Ranch gathering system throughput (Mcf/d)(1)	93,300	N/A	N/A
Grimes gathering system throughput (Mcf/d)	10,800	13,200	(18.2)%
Arapaho NGL product sales (gallons)	27,432,700	22,020,300	24.6%
Southeast Oklahoma gathering systems throughput (Mcf/d)	418,600	205,500	103.7%
Other Southwest			
Appleby gathering systems throughput (Mcf/d)	57,500	61,000	(5.7)%
Other gathering systems throughput (Mcf/d)(2)	10,700	9,300	15.1%
Northeast			
Appalachia(3)			
Natural gas processed (Mcf/d)	198,700	210,800	(5.7)%
Keep-whole sales (gallons)	50,977,900	49,047,900	3.9%
Percent-of-proceeds sales (gallons)	19,363,000	11,103,600	74.4%
Total NGL product sales (gallons)(4)	70,340,900	60,151,500	16.9%
Michigan			
Natural gas processed for a fee (Mcf/d)	1,600	2,800	(42.9)%
NGL product sales (gallons)	560,000	455,300	23.0%
Crude oil transported for a fee (Bbl/d)	12,800	13,600	(5.9)%
Liberty(5)			
Gathering systems throughput (Mcf/d)	33,600	N/A	N/A
NGL product sales (gallons)	1,383,200	N/A	N/A
Gulf Coast			
Refinery off-gas processed (Mcf/d)	104,200	128,100	(18.7)%
Liquids fractionated (Bbl/d)	20,000	25,300	(20.9)%

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

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

(4) Represents sales at the Siloam fractionator. The total sales in 2009 exclude 1,383,200 gallons sold by the Northeast on behalf of Liberty.

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

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 included in Item 1 of this Form 10-Q is presented on a basis consistent with the Partnership's internal management reporting, in accordance with SFAS No. 131, *Disclosure about Segments of an Enterprise and Related Information.*

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 and Travis Peak 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. Under an agreement executed in 2008 with Newfield Exploration Mid-Continent Inc., we operate a gathering system in the Granite Wash formation in the Texas panhandle which is connected to our Foss Lake processing plants. We also own the Grimes gathering system, which 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. Approximately 90% of our current volumes associated with our existing Oklahoma assets are derived from gathering contracts and approximately 10% are derived from purchase agreements. 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.
- *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 & Resources, L.L.C. ("MarkWest Liberty Midstream"), and sold a 40% interest in MarkWest Liberty Midstream to an affiliate of NGP Midstream & Resources, L.P. ("M&R"). A complete discussion of the formation of and accounting treatment for MarkWest Liberty Midstream appears in Note 3 of the accompanying Notes to the Condensed Consolidated Financial Statements included in Item 1 of this Form 10-Q. MarkWest Liberty Midstream currently operates a mechanical refrigeration plant with a capacity of 30 MMcf/d and a cryogenic processing facility with a capacity of 30 MMcf/d that was placed into service in the second quarter of 2009. We plan on adding additional processing capacity of 30 MMcf/d utilizing a second mechanical refrigeration plant before the end of the third quarter of 2009, and a second cryogenic facility with a capacity of 120 MMcf/d is expected to be in service by 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 facility processes approximately 120 to 130 MMcf/d of inlet gas out of its 142 MMcf/d capacity.

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 three months ended March 31, 2009:

	Southwest	Northeast	Liberty	Gulf Coast	Total
Revenue	57%	33%	4%	6%	100%
Net operating margin	67%	13%	7%	13%	100%

Equity investments in unconsolidated affiliates

Starfish. We own a 50% non-operating membership interest in Starfish Pipeline Company, L.L.C. ("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 *(Loss) earnings 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 Processing, L.L.C. ("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 *(Loss) earnings 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 March 31, 2009, compared to three months ended March 31, 2008

Items below *Income 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 tables below present information about operating income for the reported segments for the three months ended March 31, 2009 and 2008.

Southwest

	Three months ended March 31,			
	2009	2008	$ Change	% Change
	(in thousands)			
Revenue	$104,606	$158,076	$(53,470)	(34)%
Operating expenses:				
Purchased product costs	50,534	92,638	(42,104)	(45)%
Facility expenses	18,125	13,875	4,250	31%
Total operating expenses before items not allocated to segments	68,659	106,513	(37,854)	(36)%
Operating income before items not allocated to segments	$ 35,947	$ 51,563	$(15,616)	(30)%

Revenue. Revenue decreased for the three months ended March 31, 2009 compared to the same period in 2008 primarily due to lower commodity prices. Revenue from NGL, natural gas and condensate sales decreased across the segment by $61.5 million. The effect of the decrease in commodity prices on NGL sales was partially offset by increases in 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 $5.6 million increase in gathering and treating fee revenue due to the continued expansion of our operations in the Woodford Shale.

Purchased Product Costs. Purchased product costs decreased during the three months ended March 31, 2009 relative to the same period in 2008. Gas purchases decreased across the segment by $45.1 million due primarily to lower commodity prices.

Facility Expenses. Facility expenses increased during the three months ended March 31, 2009 compared to the same period in 2008 due primarily to the continued expansion of operations for the Woodford gathering system, including the PetroQuest acquisition in July of 2008, and the expansion of the Foss Lake gathering and processing operations.

Northeast

	Three months ended March 31,			
	2009	2008	$ Change	% Change
	(in thousands)			
Revenue	$61,592	$103,804	$(42,212)	(41)%
Operating expenses:				
Purchased product costs	50,954	62,297	(11,343)	(18)%
Facility expenses	5,165	4,782	383	8%
Total operating expenses before items not allocated to segments	56,119	67,079	(10,960)	(16)%
Operating income before items not allocated to segments	$ 5,473	$ 36,725	$(31,252)	(85)%

Revenue. Revenue decreased during the three months ended March 31, 2009 compared to the same period in 2008 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 due to expansion of the contracted volumes.

Purchased Product Costs. Purchased product costs decreased during the three months ended March 31, 2009 compared to the same period in 2008 due to lower prices for the natural gas that must be purchased to satisfy the keep-whole arrangements in the Appalachia area.

Facility Expenses. Facility expenses increased for the three months ended March 31, 2009 relative to the same period in 2008 due primarily to increases in property taxes.

Liberty

	Three months ended March 31,			
	2009	2008	$ Change	% Change
	(in thousands)			
Revenue	$6,656	$—	$6,656	N/A
Operating expenses:				
Purchased product costs	826	—	826	N/A
Facility expenses	2,539	—	2,539	N/A
Total operating expenses before items not allocated to segments	3,365	—	3,365	N/A
Operating income before items not allocated to segments	$3,291	$—	$3,291	N/A

The results of operations for the three months ended March 31, 2009 include our operations in the northern West Virginia and western Pennsylvania areas both before and after the formation of Markwest Liberty Midstream as described in Note 3 of the accompanying Notes to the Condensed Consolidated Financial Statements included in Item 1 of this Form 10-Q. Revenue for the three months ended March 31, 2009 consists of approximately $5.7 million of gathering fees that are based primarily on a fixed return on the capital invested in the gathering system. Approximately $1.0 million of the revenue relates to NGL product sales under percent of proceeds arrangements.

We did not have any operations in the Marcellus Shale during the three months ended March 31, 2008. We began construction in the second quarter of 2008 and gas gathering and processing operations in the fourth quarter of 2008.

Gulf Coast

	Three months ended March 31,			
	2009	2008	$ Change	% Change
	(in thousands)			
Revenue	$10,513	$23,162	$(12,649)	(55)%
Operating expenses:				
Facility expenses	5,271	3,827	1,444	38%
Total operating expenses before items not allocated to segments	5,271	3,827	1,444	38%
Operating income before items not allocated to segments	$ 5,242	$19,335	$(14,093)	(73)%

Revenue. Revenue is generated under percent-of-proceeds arrangements and is generally reported net of purchased product costs. We gather and process natural gas on behalf of refinery customers, sell the resulting residue gas, condensate and NGLs at market prices and remit to the refinery customers an agreed-upon percentage of the proceeds based on an index price.

Revenue decreased during the three months ended March 31, 2009 relative to the same period in 2008 due to lower commodity prices and decreased inlet volumes. The decrease in revenue was partially offset by a higher percent-of-proceeds ("POP") received from one of our refinery customer contracts that changed from a fixed POP to variable POP during the first quarter of 2008.

Facility Expenses. Facility expenses increased during the three months ended March 31, 2009 relative to the same period in 2008 due to the completion of a plant turnaround 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 three months ended March 31, 2009 and 2008. The ensuing items listed below the *Total segment revenue* and *Operating income* lines are not allocated to business segments as management does not consider these items allocable to any individual segment.

	Three months ended March 31,			
	2009	2008	$ Change	% Change
	(in thousands)			
Total segment revenue	$183,367	$285,042	$(101,675)	(36)%
Derivative gain (loss) not allocated to segments	8,304	(46,250)	54,554	(118)%
Total revenue	$191,671	$238,792	$ (47,121)	(20)%
Operating income before items not allocated to segments	$ 49,953	$107,623	$ (57,670)	(54)%
Derivative loss not allocated to segments	(20,838)	(14,210)	(6,628)	47%
Compensation expense included in facility expenses not allocated to segments	(344)	(182)	(162)	89%
Selling, general and administrative expenses	(15,927)	(22,461)	6,534	(29)%
Depreciation	(20,943)	(14,525)	(6,418)	44%
Amortization of intangible assets	(10,233)	(6,849)	(3,384)	49%
Loss on disposal of property, plant and equipment	(729)	(3)	(726)	24,200%
Accretion of asset retirement obligations	(47)	(32)	(15)	47%
(Loss) income from operations	(19,108)	49,361	(68,469)	(139)%
(Loss) earnings from unconsolidated affiliates	(105)	1,551	(1,656)	(107)%
Interest income	41	514	(473)	(92)%
Interest expense	(17,782)	(11,149)	(6,633)	59%
Amortization of deferred financing costs and discount (a component of interest expense)	(1,391)	(1,043)	(348)	33%
Miscellaneous expense	(662)	(33)	(629)	1,906%
(Loss) income before provision for income tax	$(39,007)	$ 39,201	$ (78,208)	(200)%

Derivative Gain (Loss) Not Allocated to Segments. The net derivative loss not allocated to segments increased by $6.6 million during the three months ended March 31, 2009 compared to the same period in 2008. Unrealized loss from the mark-to-market of our derivative instruments changed by $(70.6) million while realized gain from the settlement of our derivative instruments changed by $64.0 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 4 of the accompanying Notes to the Condensed Consolidated Financial Statements included in Item 1 of this Form 10-Q.

Selling, General and Administrative Expenses. Selling, general and administrative expenses decreased during the three months ended March 31, 2009 compared to the same period in 2008 primarily due to lower expense related to share-based compensation plans. During the first quarter of 2009, no expense was recognized for the 2009 performance based phantom units as the established performance targets are not currently expected to be achieved. Additionally, the Partnership incurred $2.6 million of expenses related to the Merger during the three months ended March 31, 2008, which did not recur in 2009.

Depreciation and Amortization of Intangible Assets. Depreciation and amortization expense increased during the three months ended March 31, 2009 compared to the same period in 2008 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 $5.4 million increase is due to depreciation on additional projects completed during 2008 and the first quarter of 2009.

Interest Expense. Interest expense increased during the three months ended March 31, 2009 relative to the same period in 2008 primarily due to additional borrowings in 2008 at higher interest rates to fund the Merger and our capital plan. The increase in interest expense was partially offset by a $3.8 million increase in capitalized interest.

Provision for Income Tax. Refer to Note 14 in the accompanying Condensed Consolidated Financial Statements for a discussion of the significant changes in the provision for income tax.

The current provision for income tax was $6.3 million for the three months ended March 31, 2009. Approximately $5.7 million is attributable to MarkWest Hydrocarbon, Inc. Of this amount, $5.9 million is attributable to MarkWest Hydrocarbon's ownership of Class A units, and the remaining benefit of $0.2 million is related to the Corporation's NGL marketing business. The remaining $0.6 million is related to taxes payable by the Partnership associated with the Texas Margin tax and Michigan Business Taxes.

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.

As a result of the joint venture agreement with M&R to form MarkWest Liberty Midstream and the expansion of our credit facility, we have significantly improved our liquidity position (see Note 3 and Note 13 for further details of the joint venture agreement and the expansion of our credit facility). Our 2009 capital plan includes approximately $425.0 million of capital expenditures for board-approved growth projects, plus approximately $5.0 million to $10.0 million for maintenance capital. Approximately $200.0 million of the 2009 capital plan relates to projects included within MarkWest Liberty Midstream. In accordance with the joint venture agreement, M&R will make contributions of $200.0 million, offsetting our cash requirements. Therefore, our net cash requirement for the 2009 growth capital plan is approximately $225.0 million. As of March 31, 2009 we have spent approximately $168.9 million, including the amount funded by M&R.

Under the joint venture agreement with M&R, we anticipate making approximately $200.0 million of additional capital contributions to fund MarkWest Liberty Midstream's capital expenditures between January 1, 2010 and December 31, 2011 in order for our share of contributed capital to be proportionate to our ownership interest. MarkWest Liberty Midstream's capital plan for 2010 and 2011 has not been finalized, so the exact timing of these contributions is currently uncertain. If we have not contributed capital in proportion to our ownership interest by the end of 2011, M&R may require us to contribute the amount of the shortfall at December 31, 2011, or may allow us to continue to fund 100% of MarkWest Liberty Midstream's capital expenditures until our total contributed capital is proportionate to our 60% ownership interest.

As a result of our joint venture agreement with ArcLight Capital Partners, L.L.C. ("ACP") executed on May 1, 2009, we further improved our liquidity position. In exchange for a 50% interest in MarkWest Pioneer, L.L.C ("MarkWest Pioneer"), we received a cash payment of $31.25 million from ACP on May 1, 2009, and will receive an additional $31.25 million upon the completion of construction of the Arkoma Connector Pipeline (see Note 22 to the accompanying Condensed Consolidated Financial Statements for further details of the joint venture agreement with ACP).

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. All expenditures on board-approved 2009 capital projects will be funded with cash flow from operations, current cash balances, contributions by our joint venture partners for capital projects within the joint ventures and our current borrowing capacity under our recently expanded revolving credit facility. However, depending upon the final capital plan for the Partnership, it may be necessary for us to raise additional funds in the future to finance our 2010 capital requirements. We intend to raise this capital through the debt and equity markets and will continue to consider the use of alternative financing strategies such as entering into additional joint venture arrangements and the sale of non-strategic assets.

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 will now be 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 May 4, 2009, we had $267.8 million of borrowings outstanding and $28.4 million of letters of credit outstanding under the revolving credit facility, leaving $139.4 million available for borrowing.

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 May 4, 2009 approximately 93% 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.

As of March 31, 2009, we and our wholly-owned subsidiary MarkWest Energy Finance Corporation had three series of senior notes outstanding: $225.0 million aggregate principal maturing in November 2014 (the "2014 Senior Notes"), and $275.0 million aggregate principal due in July 2016 (the "2016 Senior Notes"), and $500.0 million aggregate principal maturing in 2018 (the "2018 Senior Notes" and all together with the 2014 Senior Notes and 2016 Senior Notes, the "Senior Notes"). For further discussion of the Senior Notes see Note 13 to the accompanying 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.

In the future, we may raise additional capital through the issuance of debt and equity securities under our shelf registration statement or in private transactions.

The unprecedented 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 flow from operations related to the settlement of these positions. The cash flows generated by our operations could also be significantly reduced if any of our major customers defaulted. 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. Additionally, commodity prices have remained at depressed levels since the end of 2008. Our future operating performance could be negatively impacted if these conditions do not improve or continue to deteriorate.

Cash Flow

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

	Three months ended March 31,	
	2009	**2008**
Net cash provided by operating activities	$ 91,820	$ 123,228
Net cash flows used in investing activities	(175,051)	(342,095)
Net cash flows provided by financing activities	111,911	211,172

Net cash provided by operating activities decreased $31.4 million during the three months ended March 31, 2009 compared to the corresponding period in 2008. The change primarily resulted from a $57.7 million decrease in operating income, excluding derivative gains and losses, in our operating segments. The cash provided by operations for the three months ended March 31, 2008 also included $40.3 million of inflows from the return of margin deposits which did not recur in 2009. These decreases were offset by an increase of $64.0 million in net cash received from the settlement of derivative positions.

Net cash used in investing activities decreased $167.0 million during the three months ended March 31, 2009 compared to the corresponding period in 2008. This decrease was primarily due to cash paid as consideration in the Merger of $261.7 million in 2008. This decrease was offset by an increase of $94.0 million in capital expenditures primarily from our organic growth projects, where we spent approximately $166.9 million of growth capital.

Net cash provided by financing activities decreased $99.3 million during the three months ended March 31, 2009 compared to the corresponding period in 2008. The decrease was primarily due to $142.8 million decrease of net borrowings on long-term debt offset by $44.5 million in net proceeds from the sale of an equity interest in MarkWest Liberty Midstream. The cash provided by these financing activities was used primarily to fund the cost of the Merger and to raise funds for future projects.

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 March 31, 2009, our purchase obligations for the remainder of 2009 were $98.9 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.

Matters Impacting Future Results

In December 2008, our affiliate, MarkWest Pioneer commenced construction of a new interstate natural gas transmission pipeline, the Arkoma Connector Pipeline, that will extend approximately 50 miles from an interconnect with our gathering system in the Woodford Shale production area in Southeast Oklahoma to an interconnect with the Midcontinent Express Pipeline and with the Gulf Crossing Pipeline in Bennington, Oklahoma. The Arkoma Connector Pipeline will provide additional outlets for producers in the Woodford Shale as volumes continue to increase. Executed agreements are in place with certain producers to provide transportation capacity of approximately 600,000 Dth/d on the Arkoma Connector Pipeline. On May 1, 2009, we entered into an agreement to form a joint venture with ACP. Under the terms of the joint venture agreement, ACP acquired a 50% equity interest in MarkWest Pioneer for $62.5 million. The Partnership is responsible for any costs of construction in excess of $125 million.

In September 2008, Hurricane Ike caused wind and water damage to oil and gas assets in the Gulf of Mexico and Gulf Coast regions, including damage to several onshore and offshore facilities of Starfish, our unconsolidated affiliate. We contributed $8.8 million in cash for hurricane repair in 2008 and 2009 and we may receive additional capital calls. We are in the process of preparing insurance claims relating to both business interruption and property damage. As of March 31, 2009, we have not recorded a receivable for insurance recoveries with respect to our potential property loss and business interruption claims, and we have not determined the impact that any future recoveries will have on our consolidated financial statements. Along with other industry participants, we have seen our insurance costs increase substantially within this region as a result of these developments. We may be unable to obtain adequate insurance on our interest in Starfish at rates we consider reasonable and as a result may experience losses that are not fully insured. If a significant negative event that is not fully insured 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 three months ended March 31, 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		
Management evaluates the Partnership's long-lived assets, including intangibles, for impairment when events or changes in circumstances warrant such a review. A long-lived asset group is considered impaired when the estimated undiscounted cash flows from such asset group are less than the asset group's carrying value. In that event, a loss is recognized to the extent that the carrying value exceeds the fair value of the long-lived asset group.	Management considers the volume of reserves behind the asset and future NGL product and natural gas prices to estimate cash flows for each asset group. The amount of additional reserves developed by future drilling activity depends, in part, on expected commodity prices. Projections of reserves, drilling activity and future commodity prices are inherently subjective and contingent upon a number of variable factors, many of which are difficult to forecast.	A significant variance in any of these assumptions or factors could materially affect future cash flows, which could result in the impairment of an asset. A 10% decrease in the estimated future cash flows used in our impairment analysis as of March 31, 2009 would have indicated a potential impairment for five asset groups with a total net book value of $16.8 million.
Variable Interest Entities		
When the Partnership owns less than a 100% interest in an entity, management must evaluate its interests to determine if it holds 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. When management concludes that it holds a variable interest in an entity it must determine if it is the entity's primary beneficiary. A primary beneficiary absorbs a majority of the entity's expected losses or residual returns, or both. The Partnership consolidates all variable interest entities when Management determines it is the primary beneficiary.	Significant judgment is exercised in evaluating the nature of the Partnership's interest in an entity and its status as the primary beneficiary. Management uses qualitative and quantitative analysis to evaluate the Partnership's 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 its voting interests are disproportionate to its obligation to absorbs expected losses. Management evaluates whether the Partnership is the primary beneficiary of a variable interest entity by qualitatively evaluating its level of involvement in the design of the entity, and determining if the entity's activities are substantially conducted on behalf of the Partnership. A combination of qualitative and quantitative analysis is used to determine if the Partnership provides more than half of required continuing financial support to the entity, or if it absorbs a majority of the entity's expected losses or returns. After initial analysis when reconsideration events occur, management evaluates an entity and its status as the primary beneficiary to determine if the nature of its interest in the entity has changed or if the entity the design or activities of the entity have changed.	The Partnership's interest in MarkWest Liberty Midstream is considered a variable interest and the Partnership is considered the primary beneficiary. Changes in the design or nature of MarkWest Liberty Midstream, or the Partnership's involvement with MarkWest Liberty Midstream may require management to reconsider its conclusions on the entity as a variable interest entity and its status as the primary beneficiary. Such reconsideration could result in the deconsolidation of MarkWest Liberty Midstream. The deconsolidation would have a significant impact on the Partnership's financial statements.

Recent Accounting Pronouncements

Refer to Note 2 of the accompanying Condensed Consolidated Financial Statements for information regarding recent accounting pronouncements.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

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

Commodity Price Risk

Our primary risk management objective is to reduce downside volatility in our cash flows arising from changes in commodity prices related to future sales or purchases of natural gas, NGLs and crude oil. Swaps and option contracts may allow us to reduce downside volatility in our realized margins as realized losses or gains on the derivative instruments generally are offset by corresponding gains or losses in our sales of physical product. While we largely expect our realized derivative gains and losses to be offset by increases or decreases in the value of our physical sales, we will experience volatility in reported earnings due to the recording of unrealized gains and losses on our derivative positions that will have no offset. The volatility in any given period related to unrealized gains or losses can be significant to our overall results, however, we ultimately expect those gains and losses to be offset when they become realized. A committee, comprised of the senior management team of our general partner, oversees all of our risk management activity and continually monitors the risk management program and expects to continue to adjust our financial positions as conditions warrant.

To mitigate our cash flow exposure to fluctuations in the price of NGLs, we have primarily entered into derivative financial instruments relating to the future price of crude oil. To mitigate our cash flow exposure to fluctuations in the price of natural gas, we primarily utilize derivative financial instruments relating to the future price of natural gas. As a result of these transactions, we have mitigated a portion of our expected commodity price risk with agreements primarily expiring at various times through the fourth quarter of 2012.

We utilize a combination of fixed-price forward contracts, fixed-for-floating price swaps and options on the over-the-counter ("OTC") market. These types of contracts allow us to manage volatility in our margins because corresponding losses or gains on the financial instruments are generally offset by gains or losses in our physical positions.

We may enter into physical and/or financial positions to manage the risks related to commodity price exposure for our marketing activities. Due to the timing of 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 we may choose direct exposure when it is favorable as compared to the keep-whole risk.

We conduct a standard credit review on counterparties and have agreements containing collateral requirements where deemed necessary. We use standardized swap agreements that allow for offset of positive and negative exposures. 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 May 4, 2009 approximately 7% of our derivative positions, measured volumetrically, are with non-bank group counterparties and are subject to margin deposit requirements under OTC agreements that we plan to meet with letters of credit. In the unlikely event that we were unable to meet these margin calls with letters of credit, we would be forced to terminate the corresponding contracts.

The use of derivative instruments may expose us 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, potentially requiring market purchases to meet commitments, or (iii) our 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 we enter into derivative instruments, we may be prevented from realizing the benefits of favorable price changes in the physical market. We are similarly insulated, however, against unfavorable changes in such prices.

The following tables provide information on the volume of our derivative activity for positions related to long liquids and keep-whole price risk at March 31, 2009, including the weighted average prices ("WAVG"):

WTI Crude Collars	Volumes, net (Bbl/d)	WAVG Floor (Per Bbl)	WAVG Cap (Per Bbl)	Fair Value (in thousands)
2009	3,425	$67.50	$77.83	$12,711
2010 (Apr—Dec)	1,297	66.48	74.49	2,027

WTI Crude Puts	Volumes (Bbl/d)	WAVG Floor (Per Bbl)	Fair Value (in thousands)
2009	2,375	$80.00	$16,925
2010	1,191	80.00	9,155
2011	1,818	80.00	13,123

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)	Fair Value (in thousands)
2009	1,479	$119.48	$25,723
2010	1,549	61.77	(103)
2011	535	68.20	105
2012	529	70.30	(10)

Natural Gas Swaps	Volumes (MMBtu/d)	WAVG Price (Per MMBtu)	Fair Value (in thousands)
2009	9,942	$8.36	$(13,347)

The following tables provide information on the volume of our taxable subsidiary's derivative activity for positions related to long liquids and keep-whole price risk at March 31, 2009, including the WAVG:

WTI Crude Swaps	Volumes (Bbl/d)	WAVG Price (Per Bbl)	Fair Value (in thousands)
2009	3,070	$69.38	$10,703
2010	2,428	70.25	6,886
2011	3,027	87.66	21,238
2012 (Jan)	2,142	91.50	1,385

Natural Gas Swaps	Volumes (MMBtu/d)	WAVG Price (Per MMBtu)	Fair Value (in thousands)
2009	20,976	$8.15	$(21,051)
2010	10,806	8.41	(9,128)
2011	14,662	8.88	(11,086)

We have a contract with a producer in the Appalachia region which creates a floor on the frac spread for gas purchases of 9,000 Dth/d. Under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS 133"), the value of this contract is marked based on an index price through purchased product costs. As of March 31, 2009, the estimated fair value of this contract was $(2.0) million.

We have a contract which gives us an option to fix a component of the utilities cost to an index price on electricity at one of our plant locations. Under SFAS 133, the value of the derivative component of this contract is marked to market through facility expense. As of March 31, 2009, the estimated fair value of this contract was $(0.3) million.

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

The following table provides information on the derivative positions that we have entered into subsequent to March 31, 2009.

WTI Crude Collars	Volumes (Bbl/d)	WAVG Floor (Per Bbl)	WAVG Cap (Per Bbl)
2011	822	$60.00	$80.13
2012	822	60.00	85.87

Natural Gas Swaps	Volumes (MMBtu/d)	WAVG Price (Per MMBtu)
2010 (Jan, Feb, Aug, Sept)	(11,292)	$5.86

We amended certain derivative positions that were originally expected to settle during the quarter ended September 30, 2009 and will now settle during the quarter ended March 31, 2010. The fair value of these positions at March 31, 2009 was $(3.6) million.

Interest Rate

Our primary interest rate risk exposure results from the revolving portion of the Partnership Credit Agreement that has a borrowing capacity of $435.6 million and was entered into on February 20, 2008, and amended on March 2, 2009. As of May 4, 2009, we had $267.8 million outstanding borrowings on the revolving credit facility. The debt related to this agreement bears interest at variable rates that are tied to either the U.S. prime rate or the London Inter Bank Offering Rate (“LIBOR”) at the time of borrowing. We may make use of interest rate swap agreements in the future, to adjust the ratio of fixed and floating rates in our debt portfolio.

Long-Term Debt	Interest Rate	Lending Limit	Due Date	Outstanding at March 31, 2009
Partnership Credit Agreement	Variable	$435.6 million	February 2012	$294.4 million
2014 Senior Notes	Fixed	$225.0 million	November 2014	$225.0 million
2016 Senior Notes	Fixed	$275.0 million	July 2016	$275.0 million
2018 Senior Notes	Fixed	$500.0 million	April 2018	$500.0 million

Based on our overall interest rate exposure at March 31, 2009, a hypothetical increase or decrease of one percentage point in interest rates applied to borrowings under our credit facility would change earnings by approximately $2.9 million over a 12-month period. Based on our overall interest rate exposure at May 4, 2009, a hypothetical increase or decrease of one percentage point in interest rates applied to borrowings under our credit facility would change earnings by approximately $2.7 million over a 12-month period. The impact of interest rate changes described above represent the maximum impact assuming that the LIBOR rate is at or above the 2.0% interest floor. As of May 4, 2009 the one-month LIBOR was approximately 0.4% and the three-month LIBOR was approximately 1.0%

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of March 31, 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) 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 March 31, 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

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

In June 2006, the Office of Pipeline Safety ("OPS") issued a Notice of Probable Violation and Proposed Civil Penalty ("NOPV") (CPF No. 2-2006-5001) to both MarkWest Hydrocarbon and Equitable Production Company. 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 a motion to dismiss one of the counts of violations, 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. A hearing has been tentatively set for September 14, 2009, and a new schedule has been created for OPS to provide a complete administrative record, for the parties to prepare briefs for the motion to dismiss and for the OPS to rule upon the motion to dismiss prior to the hearing. MarkWest believes it has viable defenses to the remaining counts and will vigorously defend all applicable assertions of violations at the hearing.

Related to the above referenced 2004 pipeline explosion and fire incident, MarkWest Hydrocarbon and the Partnership have filed an action captioned *MarkWest Hydrocarbon, Inc., et al. v. Liberty Mutual Ins. Co., et al.* (District Court, Arapahoe County, Colorado, Case No. 05CV3953 filed August 12, 2005), as removed to the U.S. District Court for the District of Colorado, (Civil Action No. 1:05-CV-1948, on October 7, 2005) against their All-Risks Property and Business Interruption insurance carriers as a result of the insurance companies' refusal to honor their insurance coverage obligation to pay the Partnership for certain costs related to the pipeline incident. The Partnership did not provide for a receivable for any of the claims in this action because of the uncertainty as to whether and how much it would ultimately recover under the policies. On April 23, 2008, the U.S. District Court issued an order granting Defendant insurance companies' motion for summary judgment. The Partnership filed an appeal of this Order to the 10th Circuit Court of Appeals (Case No. 08-1186), but the 10th Circuit Court, after oral arguments, denied MarkWest's appeal on March 9, 2009.

With regard to the Partnership's Javelina facility, MarkWest Javelina is a party with numerous other defendants to several lawsuits brought by various plaintiffs who had residences or businesses located near the Corpus Christi industrial area, an area which included the Javelina gas processing plant, and several petroleum, petrochemical and metal processing and refining operations. These suits, *Victor Huff v. ASARCO Incorporated, et al*. (Cause No. 98-01057-F, 214th Judicial Dist. Ct., County of Nueces, Texas, original petition filed in March 3, 1998); *Jason and Dianne Gutierrez, individually and as representative of the estate of Sarina Galan Gutierrez* (Cause No. 05-2470-A, 28th Judicial District); and *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), set forth claims for wrongful death, personal injury or property damage, harm to business operations and nuisance type claims, allegedly incurred as a result of operations and emissions from the various industrial operations in the area or from products. Defendants allegedly manufactured, processed, used, or distributed. Settlements have been reached with the parties in the *Gutierrez* and *Huff* actions for immaterial amounts. The remaining action, *Valasquez, et al. v. Occidental Chemical Corp.*, 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, we are 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 our financial condition, liquidity or results of operations.

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.

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*	First Amendment to Credit Agreement entered into as of January 28, 2009, among MarkWest Energy Partners, L.P., the guarantors party thereto, Royal Bank of Canada, as Administrative Agent and Collateral Agent and as L/C Issuer, the Agents party thereto, and the lenders party thereto.
10.2*+	Contribution Agreement dated as of January 22, 2009 by and among MarkWest Liberty Gas Gathering, L.L.C., M&R MWE Liberty, LLC, and MarkWest Liberty Midstream & Resources, L.L.C.
10.3*+	Amended and Restated Limited Liability Company Agreement of MarkWest Liberty Midstream & Resources, L.L.C. dated as of February 27, 2009.
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.

* 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: May 11, 2009

/s/ FRANK M. SEMPLE

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

Date: May 11, 2009

/s/ NANCY K. BUESE

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