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

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 OR 15(d) of The Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): **December 2, 2010 (November 16, 2010)**

Vanguard Natural Resources, LLC
(Exact name of registrant as specified in its charter)

DELAWARE	**001-33756**	**61-1521161**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

5847 San Felipe, Suite 3000
Houston, Texas 77057
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code **(832) 327-2255**

(Former name or former address, if changed since last report.)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01 Other Events.

On November 16, 2010, Vanguard Natural Resources, LLC (the “Company” or “Vanguard”) and its wholly-owned subsidiary, Vanguard Natural Gas, LLC, entered into a Purchase Agreement with Denbury Resources Inc. (“Denbury”), Encore Partners GP Holdings LLC, Encore Partners LP Holdings LLC and Encore Operating, L.P. pursuant to which it will purchase all of the member interests of Encore Energy Partners GP LLC, and 20,924,055 common units of Encore Energy Partners LP, ("Encore") from Denbury. The audited consolidated financial statements of Encore and the notes thereto for each of the years ended December 31, 2009, 2008 and 2007 are included as Exhibit 99.1 hereto and are incorporated herein by reference. The unaudited consolidated financial statements of Encore and the notes thereto for the three and nine month periods ended September 30, 2010 and 2009 are included as Exhibit 99.2 hereto and are incorporated herein by reference.

The following unaudited combined pro forma financial information of the Company and the notes thereto are included in Exhibit 99.3 hereto and are incorporated herein by reference:

- Unaudited pro forma combined balance sheet as of September 30, 2010;
- Unaudited pro forma combined statement of operations for the nine months ended September 30, 2010; and
- Unaudited pro forma combined statement of operations for the year ended December 31, 2009.

The summary pro forma combined natural gas, oil and natural gas liquids reserve data of the Company is included as Exhibit 99.4 hereto and is incorporated herein by reference.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits.

The following exhibits are filed in accordance with the provisions of Item 601 of Regulation S-K:

Exhibit Number	Description of Exhibit
23.1	Consent of Ernst & Young LLP.
23.2	Consent of Miller & Lents, Ltd., Independent Petroleum Engineers and Geologists.
99.1	Encore Energy Partners, LP consolidated financial statements and the notes thereto for each of the three years ended December 31, 2009, 2008, and 2007.
99.2	Encore Energy Partners, LP consolidated financial statements and the notes thereto for each of the three and nine month periods ended September 30, 2010 and 2009.
99.3	Unaudited pro forma combined financial information of Vanguard Natural Resources, LLC.
99.4	Summary pro forma combined natural gas, oil and natural gas liquids reserve data of Vanguard Natural Resources, LLC as of December 31, 2009.

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.

VANGUARD NATURAL RESOURCES, LLC

	By:	/s/ Richard A. Robert
	Name:	Richard A. Robert
	Title:	Executive Vice President and Chief Financial Officer
December 2, 2010		(Principal Financial Officer and Principal Accounting Officer)

EXHIBIT INDEX

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Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-3 Nos. 333-159911 and 333-168177) of Vanguard Natural Resources, LLC; and
(2) Registration Statement (Form S-8 No. 333-152448) pertaining to the Vanguard Natural Resources, LLC Long-Term Incentive Plan;

of our report dated February 24, 2010 with respect to the consolidated financial statements of Encore Energy Partners LP, included in the Form 8-K of Vanguard Natural Resources, LLC.

/s/ Ernst & Young LLP

Fort Worth, Texas
December 2, 2010

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the use of our name and to our report dated January 20, 2010, relating to proved oil and natural gas reserves and future net revenues of Encore Energy Partners LP for the year ended December 31, 2009, in this Current Report of Vanguard Natural Resources, LLC on Form 8-K. We hereby consent to the incorporation by reference of said report in the Registration Statements on Form S-3 (No. 333-159911), Form S-3 (No. 333-168177) and Form S-8 (No. 333-152448).

The Registration Statements contain references to certain reports prepared by Miller and Lents, Ltd. for the exclusive use of Encore Energy Partners LP. The analysis, conclusions, and methods contained in the reports are based upon information that was in existence at the time the reports were rendered and Miller and Lents, Ltd. has not updated and undertakes no duty to update anything contained in the reports. While the reports may be used as a descriptive resource, investors are advised that Miller and Lents, Ltd. has not verified information provided by others except as specifically noted in the reports, and Miller and Lents, Ltd. makes no representation or warranty as to the accuracy of such information. Moreover, the conclusions contained in such reports are based on assumptions that Miller and Lents, Ltd. believed were reasonable at the time of their preparation and that are described in such reports in reasonable detail. However, there are a wide range of uncertainties and risks that are outside of the control of Miller and Lents, Ltd. which may impact these assumptions, including but not limited to unforeseen market changes, economic changes, natural events, actions of individuals or governments, and changes of laws and regulations or interpretation of laws and regulations.

MILLER AND LENTS, LTD.
Texas Registered Engineering Firm No. F-1442

By: /s/ Carl D. Richard, P.E.
Carl D. Richard, P. E.
Senior Vice President

Houston, Texas
December 2, 2010

Exhibit 99.1

Index to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Encore Energy Partners GP LLC
and Unitholders of Encore Energy Partners LP:

We have audited the accompanying consolidated balance sheets of Encore Energy Partners LP (the "Partnership") as of December 31, 2009 and 2008, and the related consolidated statements of operations, partners' equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Encore Energy Partners LP at December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2009, the Partnership retroactively changed its method of calculating basic and diluted earnings per common unit with the adoption of the guidance originally issued in EITF Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships* (codified in FASB ASC Topic 260, *Earnings per Share*) and FSP No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* (codified in FASB ASC Topic 260, *Earnings Per Share*). Additionally, as discussed in Note 2 to the consolidated financial statements, the Partnership has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements resulting from Accounting Standards Update No. 2010-03, *Oil and Gas Reserve Estimation and Disclosures*, effective for annual reporting periods ended on or after December 31, 2009.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Encore Energy Partners LP's internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Fort Worth, Texas
February 24, 2010

ENCORE ENERGY PARTNERS LP

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(In thousands, except unit amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,754	$ 619
Accounts receivable:		
Trade	24,543	18,965
Affiliate	8,213	3,896
Derivatives	12,881	75,131
Other	857	831
Total current assets	48,248	99,442
Properties and equipment, at cost— successful efforts method:		
Proved properties, including wells and related equipment	851,833	814,903
Unproved properties	55	84
Accumulated depletion, depreciation, and amortization	(210,417)	(154,584)
	641,471	660,403
Other property and equipment	863	802
Accumulated depreciation	(419)	(240)
	444	562
Goodwill	9,290	9,290
Other intangibles, net	3,316	3,662
Derivatives	13,423	38,497
Other	3,459	1,457
Total assets	$ 719,651	$ 813,313
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 577	$ 1,036
Affiliate	2,780	5,468
Accrued liabilities:		
Lease operating	3,683	4,252
Development capital	1,484	2,277
Interest	429	126
Production, ad valorem, and severance taxes	10,665	10,634
Derivatives	9,815	1,297
Oil and natural gas revenues payable	1,598	1,287
Other	1,659	1,502
Total current liabilities	32,690	27,879
Derivatives	13,401	3,491
Future abandonment cost, net of current portion	12,556	11,987
Long-term debt	255,000	150,000
Other	—	605
Total liabilities	313,647	193,962
Commitments and contingencies (see Note4)		
Partners' equity:		
Limited partners— 45,285,347 and 33,077,610 common units issued and outstanding, respectively	409,777	616,076
General partner— 504,851 general partner units issued and outstanding	(353)	7,534
Accumulated other comprehensive loss	(3,420)	(4,259)
Total partners' equity	406,004	619,351
Total liabilities and partners' equity	$ 719,651	$ 813,313

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

ENCORE ENERGY PARTNERS LP

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2009	**2008**	**2007**
	(In thousands, except per unit amounts)		
Revenues:			
Oil	$ 127,611	$ 226,613	$ 135,546
Natural gas	22,428	53,944	39,119
Marketing	478	5,324	8,582
Total revenues	150,517	285,881	183,247
Expenses:			
Production:			
Lease operating	41,676	44,752	33,980
Production, ad valorem, and severance taxes	16,099	28,147	17,712
Depletion, depreciation, and amortization	56,757	57,537	47,494
Exploration	3,132	196	126
General and administrative	11,375	16,605	15,245
Marketing	302	5,466	6,673
Derivative fair value loss (gain)	47,464	(96,880)	26,301
Other operating	3,099	1,670	1,426
Total expenses	179,904	57,493	148,957
Operating income (loss)	(29,387)	228,388	34,290
Other income (expenses):			
Interest	(10,974)	(6,969)	(12,702)
Other	46	99	196
Total other expenses	(10,928)	(6,870)	(12,506)
Income (loss) before income taxes	(40,315)	221,518	21,784
Income tax provision	(14)	(762)	(78)
Net income (loss	$ (40,329)	$ 220,756	$ 21,706
Net income (loss) allocation (see Note8):			
Limited partners' interest in net income (loss)	$ (39,913)	$ 163,070	$ (18,877)
General partner's interest in net income (loss)	$ (592)	$ 2,648	$ (394)
Net income (loss) per common unit:			
Basic	$ (1.01)	$ 5.33	$ (0.79)
Diluted	$ (1.01)	$ 5.21	$ (0.79)
Weighted average common units outstanding:			
Basic	39,366	30,568	23,877
Diluted	39,366	31,938	23,877

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

ENCORE ENERGY PARTNERS LP

CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY AND

COMPREHENSIVE INCOME (LOSS)

	Owner's Net Equity	Limited Partners Units	Limited Partners Amount	General Partner Units	General Partner Amount	Accumulated Other Comprehensive Loss	Total Partners' Equity
	(In thousands, except per unit amounts)						
Balance at December31, 2006	$197,810	—	$ —	—	$ —	$ —	$197,810
Contribution by EAC in connection with acquisition of the Elk Basin Assets	103,062	10,280	—	221	—	—	103,062
Net contributions from owner	119,867	—	—	—	—	—	119,867
Equity adjustment due to combination of entities under common control	(1,306)	—	—	—	—	—	(1,306)
Contribution of Permian Basin Assets by EAC	(26,229)	4,043	26,229	—	—	—	—
Allocation of owner's net equity—Permian Basin Assets	(91,956)	—	90,118	—	1,838	—	—
Allocation of owner's net equity—Permian and Williston Basin Assets	(96,877)	—	94,595	—	2,282	—	—
Allocation of owner's net equity—Arkoma Basin Assets	(17,282)	—	16,874	—	408	—	—
Allocation of owner's net equity—Williston Basin Assets	(35,034)	—	34,209	—	825	—	—
Allocation of owner's net equity—Rockies and Permian Basin Assets	(192,737)	—	188,197	—	4,540	—	—
Proceeds from issuance of common units, net of offering costs	—	9,864	193,863	284	(402)	—	193,461
Non-cash unit-based compensation	—	—	6,665	—	139	—	6,804
Cash distributions to unitholders ($0.053 per unit)	—	—	(1,311)	—	(27)	—	(1,338)
Net income attributable to owner related to pre-partnership and pre-IPO operations	40,682	—	—	—	—	—	40,682
Net loss attributable to unitholders	—	—	(18,587)	—	(389)	—	(18,976)
Balance at December31, 2007	$ —	24,187	$630,852	505	$9,214	$ —	$640,066
Net distributions to owner	—	—	(47,629)	—	(1,166)	(1)	(48,796)
Deemed distributions to affiliates in connection with acquisition of the Permian and Williston Basin Assets	—	6,885	(122,083)	—	(2,944)	—	(125,027)
Issuance of common units in exchange for net profits interest in certain Crockett County properties	—	284	5,748	—	—	—	5,748
Non-cash unit-based compensation	—	—	5,180	—	83	—	5,263
Cash distributions to unitholders ($2.3111 per unit)	—	—	(73,234)	—	(1,167)	—	(74,401)
Vesting of phantom units	—	7	—	—	—	—	—
Conversion of management incentive units	—	1,715	—	—	—	—	—
Components of comprehensive income:							
Net income attributable to owner related to pre-partnership operations of the Permian and							

Williston Basin Assets	—	—	3,321	—	80	—	3,401
Net income attributable to owner related to pre-partnership operations of the Arkoma Basin Assets	—	—	5,922	—	143	—	6,065
Net income attributable to owner related to pre-partnership operations of the Williston Basin Assets	—	—	6,637	—	164	—	6,801
Net income attributable to owner related to pre-partnership operations of the Rockies and Permian Basin Assets	—	—	34,540	—	833	—	35,373
Net income attributable to unitholders	—	—	166,822	—	2,294	—	169,116
Change in deferred hedge loss on interest rate swaps, net of tax of $12	—	—	—	—	—	(4,258)	(4,258)
Total comprehensive income							216,498
Balance at December31, 2008	$ —	33,078	$616,076	505	$7,534	$ (4,259)	$619,351
Net distributions to owner	—	—	(11,137)	—	(272)	—	(11,409)
Deemed distributions in connection with acquisition of the Arkoma Basin Assets	—	—	(45,333)	—	(1,088)	—	(46,421)
Deemed distributions in connection with acquisition of the Williston Basin Assets	—	—	(24,593)	—	(593)	—	(25,186)
Deemed distributions in connection with acquisition of the Rockies and Permian Basin Assets	—	—	(175,408)	—	(4,232)	—	(179,640)
Proceeds from issuance of common units, net of offering costs	—	12,190	170,000	—	(114)	—	169,886
Non-cash unit-based compensation	—	—	560	—	5	—	565
Cash distributions to unitholders ($2.05 per unit)	—	—	(80,617)	—	(1,035)	—	(81,652)
Vesting of phantom units and conversion of management incentive units	—	17	—	—	—	—	—
Components of comprehensive loss:							
Net loss attributable to owners prior to acquisition of the Williston Basin Assets	—	—	(188)	—	(5)	—	(193)
Net income attributable to owners prior to acquisition of the Rockies and Permian Basin Assets	—	—	360	—	9	—	369
Net loss attributable to unitholders	—	—	(39,943)	—	(562)	—	(40,505)
Change in deferred hedge loss on interest rate swaps, net of tax of $2	—	—	—	—	—	839	839
Total comprehensive loss							(39,490)
Balance at December31, 2009	$ —	45,285	$409,777	505	$(353)	$ (3,420)	$406,004

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

ENCORE ENERGY PARTNERS LP

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Cash flows from operating activities:			
Net income (loss)	$ (40,329)	$ 220,756	$ 21,706
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, and amortization	56,757	57,537	47,494
Non-cash exploration expense	—	13	23
Deferred taxes	(286)	322	16
Non-cash unit-based compensation expense	565	5,232	6,804
Non-cash derivative loss (gain)	117,685	(92,286)	27,543
Other	5,207	1,012	695
Changes in operating assets and liabilities, net of effects from acquisitions:			
Accounts receivable	(10,591)	12,437	(20,203)
Current derivatives	(2,020)	(9,586)	(2,700)
Other current assets	(221)	(176)	(417)
Long-term derivatives	(9,072)	(6,881)	(19,717)
Other assets	(3)	578	(812)
Accounts payable	(2,555)	(1,748)	3,268
Other current liabilities	(167)	2,025	9,669
Net cash provided by operating activities	114,970	189,235	73,369
Cash flows from investing activities:			
Purchases of other property and equipment	(88)	(315)	(510)
Acquisition of oil and natural gas properties	(31,960)	(215)	(495,252)
Development of oil and natural gas properties	(9,037)	(41,803)	(29,010)
Net cash used in investing activities	(41,085)	(42,333)	(524,772)
Cash flows from financing activities:			
Proceeds from issuance of common units, net of issuance costs	170,089	—	193,461
Proceeds from long-term debt, net of issuance costs	227,061	243,310	270,758
Payments on long-term debt	(125,000)	(141,000)	(225,000)
Deemed distributions to affiliates in connection with acquisitions	(251,247)	(125,027)	—
Cash distributions to unitholders	(81,652)	(74,401)	(1,338)
Contribution by EAC in connection with purchase of Elk Basin Assets	—	—	93,658
Net contributions from (distributions to) owner related to pre-partnership or pre-IPO operations	(11,409)	(48,796)	119,867
Other	(592)	(372)	—
Net cash provided by (used in) financing activities	(72,750)	(146,286)	451,406
Increase in cash and cash equivalents	1,135	616	3
Cash and cash equivalents, beginning of period	619	3	—
Cash and cash equivalents, end of period	$ 1,754	$ 619	$ 3

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

Note 1. Formation of the Partnership and Description of Business

Encore Energy Partners LP (together with its subsidiaries, "ENP"), a Delaware limited partnership, was formed by Encore Acquisition Company (together with its subsidiaries, "EAC"), a publicly traded Delaware corporation, to acquire, exploit, and develop oil and natural gas properties and to acquire, own, and operate related assets. Encore Energy Partners GP LLC (the "General Partner"), a Delaware limited liability company and indirect wholly owned subsidiary of EAC, serves as ENP's general partner and Encore Energy Partners Operating LLC ("OLLC"), a Delaware limited liability company and direct wholly owned subsidiary of ENP, owns and operates ENP's properties. ENP's properties and oil and natural gas reserves are located in four core areas:

- the Big Horn Basin in Wyoming and Montana;
- the Permian Basin in West Texas and New Mexico;
- the Williston Basin in North Dakota and Montana; and
- the Arkoma Basin in Arkansas and Oklahoma.

EAC's Merger with Denbury

On October 31, 2009, EAC, the ultimate parent of the General Partner, entered into an Agreement and Plan of Merger (the "Merger Agreement") with Denbury Resources Inc. ("Denbury") pursuant to which EAC has agreed to merge with and into Denbury, with Denbury as the surviving entity (the "Merger"). The Merger Agreement, which was unanimously approved by EAC's Board of Directors and by Denbury's Board of Directors, provides for Denbury's acquisition of all of the issued and outstanding shares of EAC common stock. Completion of the Merger is conditioned upon, among other things, approval by the stockholders of both EAC and Denbury.

Initial Public Offering and Concurrent Transactions

In September 2007, ENP completed its initial public offering ("IPO") of 9,000,000 common units at a price to the public of $21.00 per unit. In October 2007, the underwriters exercised in full their over-allotment option to purchase an additional 1,148,400 common units. The net proceeds of approximately $193.5 million, after deducting the underwriters' discount and a structuring fee of approximately $14.9 million, in the aggregate, and offering expenses of approximately $4.7 million, were used to repay in full $126.4 million of outstanding indebtedness under a subordinated credit agreement with EAP Operating, LLC ("EAP Operating"), a Delaware limited liability company and direct wholly owned subsidiary of EAC, and reduce outstanding borrowings under OLLC's revolving credit facility. Please read "Note 6. Long-Term Debt" for additional discussion of ENP's long-term debt.

At the closing of the IPO, the following transactions, among others, were completed:

(a) ENP entered into a contribution, conveyance and assumption agreement (the "Contribution Agreement") with the General Partner, OLLC, EAC, Encore Operating, L.P. ("Encore Operating"), a Texas limited partnership and indirect wholly owned subsidiary of EAC, and Encore Partners LP Holdings LLC, a Delaware limited liability company and direct wholly owned subsidiary of EAC. The following transactions, among others, occurred pursuant to the Contribution Agreement:

- Encore Operating contributed certain oil and natural gas properties and related assets in the Permian Basin in West Texas (the "Permian Basin Assets") to ENP in exchange for 4,043,478 common units; and
- EAC agreed to indemnify ENP for certain environmental liabilities, tax liabilities, and title defects, as well as defects relating to retained assets and liabilities, occurring or existing before the closing.

These transfers and distributions were made in a series of steps outlined in the Contribution Agreement. In connection with the issuance of the common units by ENP in exchange for the Permian Basin Assets, the IPO, and the exercise of the underwriters' over-allotment option to purchase additional common units, the General Partner exchanged such number of common units for general partner units as was necessary to enable it to maintain its then two percent general partner interest in ENP. The General Partner received the common units through capital contributions from EAC of common units it owned.

(b) ENP entered into an administrative services agreement (the "Administrative Services Agreement") with the General Partner, OLLC, Encore Operating, and EAC pursuant to which Encore Operating performs administrative services for ENP. Please read "Note 11. Related Party Transactions" for additional discussion regarding the Administrative Services Agreement.

(c) The Encore Energy Partners GP LLC Long-Term Incentive Plan (the "LTIP") was adopted by the board of directors of the General Partner. Please read "Note 9. Unit-Based Compensation Plans" for additional discussion regarding the LTIP.

Note 2. Summary of Significant Accounting Policies

Principles of Consolidation

ENP's consolidated financial statements include the accounts of its wholly owned subsidiaries. All material intercompany balances and transactions have been eliminated in consolidation.

As discussed in "Note 1. Formation of the Partnership and Description of Business," upon completion of ENP's IPO, EAC contributed the Permian Basin Assets to ENP. The Permian Basin Assets are considered the predecessor to ENP (the "Predecessor"), and therefore, the historical results of operations of ENP include the results of operations of the Permian Basin Assets for all periods presented.

In February 2008, ENP acquired certain oil and natural gas properties and related assets in the Permian Basin in West Texas and in the Williston Basin in North Dakota (the "Permian and Williston Basin Assets") from Encore Operating. In January 2009, ENP acquired certain oil and natural gas properties and related assets in the Arkoma Basin in Arkansas and royalty interest properties primarily in Oklahoma, as well as 10,300 unleased mineral acres (the "Arkoma Basin Assets") from Encore Operating. In June 2009, ENP acquired certain oil and natural gas properties and related assets in the Williston Basin in North Dakota and Montana (the "Williston Basin Assets") from Encore Operating. In August 2009, ENP acquired certain oil and natural gas properties and related assets in the Big Horn Basin in Wyoming, the Permian Basin in West Texas and New Mexico, and the Williston Basin in Montana and North Dakota (the "Rockies and Permian Basin Assets") from Encore Operating. Because these assets were acquired from an affiliate, the acquisitions were accounted for as transactions between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of the acquired properties were recorded at Encore Operating's carrying value and ENP's historical financial information was recast to include the acquired properties for all periods in which the properties were owned by Encore Operating. Accordingly, the consolidated financial statements and notes thereto reflect the historical results of ENP combined with those of the Permian and Williston Basin Assets, the Arkoma Basin Assets, the Williston Basin Assets, and the Rockies and Permian Basin Assets. Please read "Note 3. Acquisitions" for additional discussion of these acquisitions.

The results of operations of the Williston Basin Assets and the Rockies and Permian Basin Assets related to pre-partnership operations were allocated to the EAC affiliates based on their respective ownership percentages in ENP. The effect of recasting ENP's consolidated financial statements to account for this common control transaction increased ENP's net income by approximately $42.2 million and $23.9 million in 2008 and 2007, respectively.

ENP, the Permian Basin Assets, the Permian and Williston Basin Assets, the Arkoma Basin Assets, Williston Basin Assets, and the Rockies and Permian Basin Assets were owned by EAC prior to the closing of the IPO, with the exception of management incentive units owned by certain executive officers of the General Partner.

Use of Estimates

Preparing financial statements in conformity with accounting principles generally accepted in the United States ("GAAP") requires management to make certain estimations and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses, and the disclosure of contingent assets and liabilities in the consolidated financial statements. Actual results could differ materially from those estimates.

Estimates made in preparing these consolidated financial statements include, among other things, estimates of the proved oil and natural gas reserve volumes used in calculating depletion, depreciation, and amortization ("DD&A") expense; the estimated future cash flows and fair value of properties used in determining the need for any impairment write-down; operating costs accrued; volumes and prices for revenues accrued; estimates of the fair value of unit-based compensation awards; and the timing and amount of future abandonment costs used in calculating asset retirement obligations. Changes in the assumptions used could have a significant impact on reported results in future periods.

Cash and Cash Equivalents

Cash and cash equivalents include cash in banks, money market accounts, and all highly liquid investments with an original maturity of three months or less. On a bank-by-bank basis and considering legal right of offset, cash accounts that are overdrawn are reclassified to current liabilities and any change in cash overdrafts is shown as "Change in cash overdrafts" in the "Financing activities" section of ENP's Consolidated Statements of Cash Flows.

Prior to the formation of ENP, EAC provided cash as needed to support the operations of the Predecessor and collected cash from sales of production. Net cash received by or paid to EAC for periods prior to the properties' ownership by ENP is reflected as net contributions from owner or net distributions to owner on the accompanying Consolidated Statements of Partners' Equity and Comprehensive Income (Loss) and Consolidated Statements of Cash Flows.

The following table sets forth supplemental disclosures of cash flow information for the periods indicated:

	Year Ended December 31,		
	2009	**2008**	**2007**
		(In thousands)	
Cash paid during the period for:			
Interest	$ 9,761	$ 6,614	$ 11,857
Income taxes	297	—	—
Non-cash investing and financing activities:			
Contribution of commodity derivative contracts from EAC	—	—	9,404
Contribution of Permian Basin Assets from EAC	—	—	26,229
Issuance of common units in connection with acquisition of net profits interest in certain Crockett County properties(a)	—	5,748	—
Issuance of common units in connection with acquisition of the Permian and Williston Basin Assets(a)	—	125,027	—

(a) Please read "Note 3. Acquisitions" for additional discussion.

Accounts Receivable

Trade accounts receivable, which are primarily from oil and natural gas sales, are recorded at the invoiced amount and do not bear interest. ENP routinely reviews outstanding accounts receivable balances and assesses the financial strength of its customers and records a reserve for amounts not expected to be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted. At December 31, 2009 and 2008, ENP had no allowance for doubtful accounts.

Properties and Equipment

Oil and Natural Gas Properties. ENP uses the successful efforts method of accounting for its oil and natural gas properties under Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 932 (formerly Statement of Financial Accounting Standards ("SFAS") No. 19, "*Financial Accounting and Reporting by Oil and Gas Producing Companies*"). Under this method, all costs associated with productive and nonproductive development wells are capitalized. Exploration expenses, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Costs associated with drilling exploratory wells are initially capitalized pending determination of whether the well is economically productive or nonproductive.

If an exploratory well does not find reserves or does not find reserves in a sufficient quantity as to make them economically producible, the previously capitalized costs would be expensed in ENP's Consolidated Statements of Operations and shown as an adjustment to net income (loss) in the "Operating activities" section of ENP's Consolidated Statements of Cash Flows in the period in which the determination was made. If an exploratory well finds reserves but they cannot be classified as proved, ENP continues to capitalize the associated cost as long as the well has found a sufficient quantity of reserves to justify its completion as a producing well and ENP is making sufficient progress in assessing the reserves and the operating viability of the project. If subsequently it is determined that these conditions do not continue to exist, all previously capitalized costs associated with the exploratory well would be expensed and shown as an adjustment to net income (loss) in the "Operating activities" section of ENP's Consolidated Statements of Cash Flows in the period in which the determination was made. Re-drilling or directional drilling in a previously abandoned well is classified as development or exploratory based on whether it is in a proved or unproved reservoir. Costs for repairs and maintenance to sustain or increase production from the existing producing reservoir are charged to expense as incurred. Costs to recomplete a well in a different unproved reservoir are capitalized pending determination that economic reserves have been added. If the recompletion is unsuccessful, the costs would be charged to expense. All capitalized costs associated with both development and exploratory wells are shown as "Development of oil and natural gas properties" in the "Investing activities" section of ENP's Consolidated Statements of Cash Flows.

Significant tangible equipment added or replaced that extends the useful or productive life of the property is capitalized. Costs to construct facilities or increase the productive capacity from existing reservoirs are capitalized. Capitalized costs are amortized on a unit-of-production basis over the remaining life of proved developed reserves or total proved reserves, as applicable. Natural gas volumes are converted to barrels of oil equivalent ("BOE") at the rate of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of oil.

The costs of retired, sold, or abandoned properties that constitute part of an amortization base are charged or credited, net of proceeds received, to accumulated DD&A.

Miller and Lents, Ltd., ENP's independent reserve engineer, estimates ENP's reserves annually on December 31. This results in a new DD&A rate which ENP uses for the preceding fourth quarter after adjusting for fourth quarter production. ENP internally estimates reserve additions and reclassifications of reserves from proved undeveloped to proved developed at the end of the first, second, and third quarters for use in determining a DD&A rate for the respective quarter.

In accordance with ASC 360-10, 205, 840, 958, and 855-10-60-1 (formerly SFAS No. 144, " *Accounting for the Impairment or Disposal of Long-Lived Assets*") ENP assesses the need for an impairment of long-lived assets to be held and used, including proved oil and natural gas properties, whenever events and circumstances indicate that the carrying value of the asset may not be recoverable. If impairment is indicated based on a comparison of the asset's carrying value to its undiscounted expected future net cash flows, then an impairment charge is recognized to the extent the asset's carrying value exceeds its fair value. Expected future net cash flows are based on existing proved reserves (and appropriately risk-adjusted probable reserves), forecasted production information, and management's outlook of future commodity prices. Any impairment charge incurred is expensed and reduces the net basis in the asset. Management aggregates proved property for impairment testing the same way as for calculating DD&A. The price assumptions used to calculate undiscounted cash flows is based on judgment. ENP uses prices consistent with the prices it believes a market participant would use in bidding on acquisitions and/or assessing capital projects. These price assumptions are critical to the impairment analysis as lower prices could trigger impairment.

Unproved properties, the majority of which relate to the acquisition of leasehold interests, are assessed for impairment on a property-by-property basis for individually significant balances and on an aggregate basis for individually insignificant balances. If the assessment indicates impairment, a loss is recognized by providing a valuation allowance at the level at which impairment was assessed. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms, and potential shifts in business strategy employed by management. In the case of individually insignificant balances, the amount of the impairment loss recognized is determined by amortizing the portion of these properties' costs which ENP believes will not be transferred to proved properties over the remaining life of the lease.

Amounts shown in the accompanying Consolidated Balance Sheets as "Proved properties, including wells and related equipment" consisted of the following as of the dates indicated:

	December 31,	
	2009	2008
	(In thousands)	
Proved leasehold costs	$ 609,692	$ 580,695
Wells and related equipment— Completed	241,953	227,970
Wells and related equipment— In process	188	6,238
Total proved properties	$ 851,833	$ 814,903

Other Property and Equipment. Other property and equipment is carried at cost. Depreciation is expensed on a straight-line basis over estimated useful lives, which range from three to seven years. Gains or losses from the disposal of other property and equipment are recognized in the period realized and included in "Other operating expense" in the accompanying Consolidated Statements of Operations.

Goodwill and Other Intangible Assets

ENP accounts for goodwill and other intangible assets under the provisions of ASC 350, 730-10-60-3, 323-10-35-13, 205-20-60-4, and 280-10-60-2 (formerly SFAS No. 142, "*Goodwill and Other Intangible Assets*"). Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations. Goodwill is tested for impairment annually on December 31 or whenever indicators of impairment exist. The goodwill test is performed at the reporting unit level. ENP has determined that it has only one reporting unit, which is oil and natural gas production in the United States. If indicators of impairment are determined to exist, an impairment charge is recognized for the amount by which the carrying value of goodwill exceeds its implied fair value.

ENP utilizes both a market capitalization and an income approach to determine the fair value of its reporting units. The primary component of the income approach is the estimated discounted future net cash flows expected to be recovered from the reporting unit's oil and natural gas properties. ENP's analysis concluded that there was no impairment of goodwill as of December 31, 2009. Significant decreases in the prices of oil and natural gas or significant negative reserve adjustments from the December 31, 2009 assessment could change ENP's estimates of the fair value of its reporting units and could result in an impairment charge.

Intangible assets with definite useful lives are amortized over their estimated useful lives. In accordance with ASC 410-20, 450-20, 835-20, 360-10-35, 840-10, and 980-410, ENP evaluates the recoverability of intangible assets with definite useful lives whenever events or changes in circumstances indicate that the carrying value of the asset may not be fully recoverable. An impairment loss exists when the estimated undiscounted cash flows expected to result from the use of the asset and its eventual disposition are less than its carrying amount.

ENP is a party to a contract allowing it to purchase a certain amount of natural gas at a below market price for use as field fuel. As of December 31, 2009, the gross carrying value of this contact was $4.2 million and accumulated amortization was $0.9 million. During each of 2009, 2008, and 2007, ENP recorded approximately $0.3 million of amortization expense related to this contract. The net carrying value is shown as "Other intangibles, net" on the accompanying Consolidated Balance Sheets and is being amortized on a straight-line basis through November 2020. ENP expects to recognize $0.3 million of amortization expense during each of the next five years related to this contract.

Asset Retirement Obligations

In accordance with ASC 410-20, 450-20, 835-20, 360-10-35, 840-10, and 980-410 (formerly SFAS No. 143, " *Accounting for Asset Retirement Obligations*"), ENP recognizes the fair value of a liability for an asset retirement obligation in the period in which the liability is incurred. For oil and natural gas properties, this is the period in which the property is acquired or a new well is drilled. An amount equal to and offsetting the liability is capitalized as part of the carrying amount of ENP's oil and natural gas properties. The liability is recorded at its discounted risk adjusted fair value and then accreted each period until it is settled or the asset is sold, at which time the liability is reversed. Estimates are based on historical experience in plugging and abandoning wells and estimated remaining field life based on reserve estimates. Please read "Note 5. Asset Retirement Obligations" for additional information.

Unit-Based Compensation

ENP does not have any employees. However, the LTIP allows for the grant of unit awards and unit-based awards for employees, consultants, and directors of EAC, the General Partner, and any of their affiliates that perform services for ENP. ENP accounts for unit-based compensation according to the provisions of ASC 718, 505-50, and 260-10-60-1A (formerly SFAS No. 123 (revised 2004), "*Share-Based Payment*"), which requires the recognition of compensation expense for unit-based awards over the requisite service period in an amount equal to the grant date fair value of the awards. Please read "Note 9. Unit-Based Compensation Plans" for additional discussion of ENP's unit-based compensation plans.

Segment Reporting

ENP operates in only one industry: the oil and natural gas exploration and production industry in the United States. All revenues are derived from customers located in the United States.

Major Customers / Concentration of Credit Risk

The following purchasers accounted for 10 percent or greater of the sales of production for the period indicated:

	Percentage of Total Sales of Production for the Year Ended December 31,		
Purchaser	**2009**	**2008**	**2007**
Marathon Oil Corporation	43%	19%	24%
ConocoPhillips	(a)	17%	10%
Tesoro Refining & Marketing Co	(a)	15%	17%

(a) Less than 10 percent for the period indicated.

Income Taxes

ENP is treated as a partnership for federal and state income tax purposes with each partner being separately taxed on his share of ENP's taxable income. Therefore, no provision for current or deferred federal income taxes has been provided for in the accompanying consolidated financial statements. However, the portion of ENP's operations that is located in Texas is subject to an entity-level tax, the Texas margin tax, at an effective rate of up to 0.7 percent of income that is apportioned to Texas beginning with tax reports due on or after January 1, 2008. Deferred tax assets and liabilities are recognized for future Texas margin tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective Texas margin tax bases.

Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the partnership agreement. In addition, individual unitholders have different investment bases depending upon the timing and price of acquisition of their common units, and each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, differs from the accounting followed in the consolidated financial statements. As a result, the aggregate difference in the basis of net assets for financial and tax reporting purposes cannot be readily determined as ENP does not have access to information about each unitholder's tax attributes in ENP.

ENP accounts for uncertainty in income taxes in accordance with ASC 740, 805-740, and 835-10 (formerly FASB Interpretation No. 48, " *Accounting for Uncertainty in Income Taxes — an Interpretation of FASB Statement No. 109*"). ENP performs a periodic evaluation of tax positions to review the appropriate recognition threshold for each tax position recognized in its consolidated financial statements. As of December 31, 2009 and 2008, all of ENP's tax positions met the "more-likely-than-not" threshold prescribed by ASC 740, 805-740, and 835-10. As a result, no additional tax expense, interest, or penalties have been accrued.

Oil and Natural Gas Revenue Recognition

Oil and natural gas revenues are recognized as oil and natural gas is produced and sold, net of royalties. Royalties and severance taxes are incurred based upon the actual price received from the sales. To the extent actual volumes and prices of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded as "Accounts receivable — trade" in the accompanying Consolidated Balance Sheets. Natural gas revenues are reduced by any processing and other fees incurred except for transportation costs paid to third parties, which are recorded as "Other operating expense" in the accompanying Consolidated Statements of Operations. Natural gas revenues are recorded using the sales method of accounting whereby revenue is recognized based on actual sales of natural gas rather than ENP's proportionate share of natural gas production. If ENP's overproduced imbalance position (*i.e.*, ENP has cumulatively been over-allocated production) is greater than ENP's share of remaining reserves, a liability is recorded for the excess at period-end prices unless a different price is specified in the contract in which case that price is used. Revenue is not recognized for the production in tanks, oil marketed on behalf of joint owners in ENP's properties, or oil in pipelines that has not been delivered to the purchaser.

Natural gas imbalances at December 31, 2009 and 2008 were 15,139 million British thermal units ("MMBtu") and 38,010 MMBtu, respectively, over-delivered to ENP, the value of which was approximately $0.1 million and $0.2 million, respectively.

Marketing Revenues and Expenses

In March 2007, ENP acquired a crude oil pipeline and a natural gas pipeline as part of the Big Horn Basin acquisition. Natural gas volumes are purchased from numerous gas producers at the inlet of the pipeline and resold downstream to various local and off-system markets. In addition, pipeline tariffs are collected for transportation through the crude oil pipeline.

Marketing revenues includes the sales of oil and natural gas purchased from third parties, as well as pipeline tariffs charged for transportation volumes through ENP's pipelines. Marketing revenues derived from sales of oil or natural gas purchased from third parties are recognized when persuasive evidence of a sales arrangement exists, delivery has occurred, the sales price is fixed or determinable, and collectibility is reasonably assured. As ENP takes title to the oil and natural gas and has risks and rewards of ownership, these transactions are presented gross in the accompanying Consolidated Statements of Operations, unless they meet the criteria for netting as outlined in ASC 845-10 (formerly Emerging Issues Task Force ("EITF") Issue No. 04-13, " *Accounting for Purchases and Sales of Inventory with the Same Counterparty* ").

Shipping Costs

Shipping costs in the form of pipeline fees and trucking costs paid to third parties are incurred to transport oil and natural gas production from certain properties to a different market location for ultimate sale. These costs are included in "Other operating expense" and "Marketing expense," as applicable, in the accompanying Consolidated Statements of Operations.

Derivatives

ENP uses various financial instruments for non-trading purposes to manage and reduce price volatility and other market risks associated with its oil and natural gas production. These arrangements are structured to reduce ENP's exposure to commodity price decreases, but they can also limit the benefit ENP might otherwise receive from commodity price increases. ENP's risk management activity is generally accomplished through over-the-counter derivative contracts with large financial institutions. ENP also use derivative instruments in the form of interest rate swaps, which hedge its risk related to interest rate fluctuation.

ENP applies the provisions of ASC 815 (formerly SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities* "), which requires each derivative instrument to be recorded in the balance sheet at fair value. If a derivative has not been designated as a hedge or does not otherwise qualify for hedge accounting, it must be adjusted to fair value through earnings. However, if a derivative qualifies for hedge accounting, depending on the nature of the hedge, the effective portion of changes in fair value can be recognized in accumulated other comprehensive income or loss until such time as the hedged item is recognized in earnings. In order to qualify for cash flow hedge accounting, the cash flows from the hedging instrument must be highly effective in offsetting changes in cash flows of the hedged item. In addition, all hedging relationships must be designated, documented, and reassessed periodically.

ENP has elected to designate its outstanding interest rate swaps as cash flow hedges. The effective portion of the mark-to-market gain or loss on these derivative instruments is recorded in "Accumulated other comprehensive loss" on the accompanying Consolidated Balance Sheets and reclassified into earnings in the same period in which the hedged transaction affects earnings. Any ineffective portion of the mark-to-market gain or loss is recognized in earnings and included in "Derivative fair value loss (gain)" in the accompanying Consolidated Statements of Operations.

ENP has not elected to designate its current portfolio of commodity derivative contracts as hedges. Therefore, changes in fair value of these derivative instruments are recognized in earnings and included in "Derivative fair value loss (gain)" in the accompanying Consolidated Statements of Operations.

Earnings Per Unit

ENP's net income (loss) is allocated to partner equity accounts in accordance with the provisions of the partnership agreement. For purposes of calculating earnings per unit, ENP allocates net income (loss) to its limited partners and participating securities, including general partner units, each quarter under the provisions of ASC 260-10 (formerly EITF Issue No. 03-6, "*Participating Securities and the Two {d208} Class Method under FASB Statement No. 128*"). Under the two-class method of calculating earnings per unit, earnings are allocated to participating securities as if all the earnings for the period had been distributed. A participating security is any security that may participate in distributions with common units. For purposes of calculating earnings per unit, general partner units, unvested phantom units, and unvested management incentive units are considered participating securities. Net income (loss) per common unit is calculated by dividing the limited partners' interest in net income (loss), after deducting the interests of participating securities, by the weighted average common units outstanding. Please read "New Accounting Pronouncements" below and "Note 8. Earnings Per Unit" for additional discussion.

Comprehensive Income (Loss)

ENP has elected to show comprehensive income (loss) as part of its Consolidated Statements of Partners' Equity and Comprehensive Income (Loss) rather than in its Consolidated Statements of Operations or in a separate statement.

FASB Launches Accounting Standards Codification

In June 2009, the FASB issued ASC 105-10 (formerly SFAS No. 168, "*The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles*"). ASC 105-10 establishes the Codification as the sole source of authoritative accounting principles recognized by the FASB to be applied by all nongovernmental entities in the preparation of financial statements in conformity with GAAP. ASC 105-10 was prospectively effective for financial statements issued for fiscal years ending on or after September 15, 2009, and interim periods within those fiscal years. The adoption of ASC 105-10 on July 1, 2009 did not impact ENP's results of operations or financial condition.

Following the Codification, the FASB does not issue new standards in the form of Statements, FASB Staff Positions ("FSP"), or EITF Abstracts. Instead, it issues Accounting Standards Updates ("ASU"), which update the Codification, provide background information about the guidance, and provide the basis for conclusions on the changes to the Codification.

The Codification did not change GAAP; however, it did change the way GAAP is organized and presented. As a result, these changes impact how companies, including ENP, reference GAAP in their financial statements and in their significant accounting policies.

New Accounting Pronouncements

ASC 820-10 (formerly FSP No. FAS 157-2, "Effective Date of FASB Statement No. 157")

In February 2008, the FASB issued ASC 820-10, which delayed the effective date of ASC 820-10 for one year for nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). ASC 820-10 was prospectively effective for financial statements issued for fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. ENP elected a partial deferral of ASC 820-10 for all instruments within the scope of ASC 820-10, including, but not limited to, its asset retirement obligations and indefinite lived assets. The adoption of ASC 820-10 on January 1, 2009 as it relates to nonfinancial assets and liabilities did not have a material impact on ENP's results of operations or financial condition. Please read "Note 10. Fair Value Measurements" for additional discussion.

ASC 805 (formerly SFAS No. 141 (revised 2007), "Business Combinations")

In December 2007, the FASB issued ASC 805, which establishes principles and requirements for the reporting entity in a business combination, including: (1) recognition and measurement in the financial statements of the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (2) recognition and measurement of goodwill acquired in the business combination or a gain from a bargain purchase; and (3) determination of the information to be disclosed to enable financial statement users to evaluate the nature and financial effects of the business combination. In April 2009, the FASB issued ASC 805-20 (formerly FSP No. FAS 141(R)-1, "Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arises from Contingencies"), which amends and clarifies ASC 805 to address application issues, including: (1) initial recognition and measurement; (2) subsequent measurement and accounting; and (3) disclosure of assets and liabilities arising from contingencies in a business combination. ASC 805 and ASC 805-20 were prospectively effective for business combinations consummated in fiscal years beginning on or after December 15, 2008. The accounting for transactions between entities under common control is unchanged under ASC 805 and ASC 805-20. The application of ASC 805 and ASC 805-20 to the acquisition of certain oil and natural gas properties and related assets during 2009 was nominal. Please read "Note 3. Acquisitions" for additional discussion.

ASC 815-10 (formerly SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities — an amendment of FASB Statement No. 133")

In March 2008, the FASB issued ASC 815-10, which requires enhanced disclosures: including (1) how and why an entity uses derivative instruments; (2) how derivative instruments and related hedged items are accounted for under ASC 815; and (3) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. ASC 815-10 was prospectively effective for financial statements issued for fiscal years beginning on or after November 15, 2008, and interim periods within those fiscal years. The adoption of ASC 815-10 on January 1, 2009 required additional disclosures regarding ENP's derivative instruments; however, it did not impact ENP's results of operations or financial condition. Please read "Note 10. Fair Value Measurements" for additional discussion.

ASC 260-10 (formerly EITF Issue No. 07-4, "Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships")

In March 2008, the FASB issued ASC 260-10, which addresses how master limited partnerships should calculate earnings per unit using the two-class method and how current period earnings of a master limited partnership should be allocated to the general partner, limited partners, and other participating securities. ASC 260-10 was retrospectively effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years. In the accompanying Consolidated Financial Statements, periods prior to the adoption of ASC 260-10 have been restated to calculate earnings per unit in accordance with this pronouncement. The retrospective application of ASC 260-10 reduced ENP's basic and diluted earnings per common unit by $0.01 for the year ended December 31, 2007. The adoption of ASC 260-10 did not have an impact on ENP's basic or diluted earnings per common unit for the year ended December 31, 2008. Please read "Note 8. Earnings Per Unit" for additional discussion.

ASC 260-10 (formerly FSP No. EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities")

In June 2008, the FASB issued ASC 260-10, which addresses whether instruments granted in unit-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation for computing basic earnings per unit under the two-class method. ASC 260-10 was retroactively effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years. In the accompanying Consolidated Financial Statements, periods prior to the adoption of ASC 260-10 have been restated to calculate earnings per unit in accordance with this pronouncement. Please read "Note 8. Earnings Per Unit" for additional discussion.

SEC Release No. 33-8995, "Modernization of Oil and Gas Reporting" ("Release 33-8995")

In December 2008, the United States Securities and Exchange Commission (the "SEC") issued Release 33-8995, which amends oil and natural gas reporting requirements under Regulations S-K and S-X. Release 33-8995 also adds a section to Regulation S-K (Subpart 1200) to codify the revised disclosure requirements in Securities Act Industry Guide 2, which is being phased out. Release 33-8995 permits the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. Release 33-8995 will also allow companies to disclose their probable and possible reserves to investors at the company's option. In addition, the new disclosure requirements require companies to: (1) report the independence and qualifications of its reserves preparer or auditor; (2) file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit; and (3) report oil and gas reserves using an average price based upon the prior 12-month period rather than a year-end price, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. Release 33-8995 was prospectively effective for financial statements issued for fiscal years ending on or after December 31, 2009.

ASC 855-10 (formerly SFAS No. 165, "Subsequent Events")

In June 2009, the FASB issued ASC 855-10 to establish general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or available to be issued. In particular, ASC 855-10 sets forth: (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. ASC 855-10 was prospectively effective for financial statements issued for interim or annual periods ending after June 15, 2009. The adoption of ASC 855-10 on June 30, 2009 did not impact ENP's results of operations or financial condition.

ASU No. 2009-05, "Fair Value Measurement and Disclosure: Measuring Liabilities at Fair Value" ("ASU 2009-05")

In August 2009, the FASB issued ASU 2009-05 to provide clarification on measuring liabilities at fair value when a quoted price in an active market is not available. In particular, ASU 2009-05 specifies that a valuation technique should be applied that used either the quote of the liability when traded as an asset, the quoted prices for similar liabilities or similar liabilities when traded as assets, or another valuation technique consistent with existing fair value measurement guidance. ASU 2009-05 was prospectively effective for financial statements issued for interim or annual periods ending after October 1, 2009. The adoption of ASU 2009-05 on December 31, 2009 did not impact ENP's results of operations or financial condition.

ASU No. 2010-03, "Oil and Gas Reserve Estimation and Disclosure" ("ASU 2010-03")

In January 2010, the FASB issued ASU 2010-03 to align the oil and natural gas reserve estimation and disclosure requirements of Extractive Activities — Oil and Gas (ASC 932) with the requirements in the SEC's final rule, "Modernization of the Oil and Gas Reporting." ASU 2010-03 was prospectively effective for financial statements issued for annual periods ending on or after December 31, 2009.

ASU No. 2010-06, "Improving Disclosures about Fair Value Measurements" ("ASU 2010-06")

In January 2010, the FASB issued ASU 2010-06 to require additional information to be disclosed principally in respect of level 3 fair value measurements and transfers to and from Level 1 and Level 2 measurements; in addition, enhanced disclosure is required concerning inputs and valuation techniques used to determine Level 2 and Level 3 fair value measurements. ASU 2010-06 was generally effective for interim and annual reporting periods beginning after December 15, 2009; however, the requirements to disclose separately purchases, sales, issuances, and settlements in the Level 3 reconciliation are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years) with early adoption allowed. The adoption of ASU 2010-06 on December 31, 2009 did not impact ENP's results of operations or financial condition.

Note 3. Acquisitions

Rockies and Permian Basin Assets

In August 2009, ENP acquired the Rockies and Permian Basin Assets from Encore Operating for approximately $179.6 million in cash, which was financed through borrowings under OLLC's revolving credit facility and proceeds from the issuance of ENP common units to the public. As previously discussed, the acquisition was accounted for as a transaction between entities under common control. Therefore, the assets and liabilities of the acquired properties were recorded at Encore Operating's carrying value as of July 31, 2009 of approximately $194.4 million and $4.2 million, respectively, and the historical financial information of ENP was recast to include the Rockies and Permian Basin Assets for all periods the properties were owned by Encore Operating. As the historical basis in the Rockies and Permian Basin Assets is included in the accompanying Consolidated Balance Sheets, the cash purchase price was recorded as a deemed distribution when paid to EAC.

Williston Basin Assets

In June 2009, ENP acquired the Williston Basin Assets from Encore Operating for approximately $25.2 million in cash, which was financed through borrowings under OLLC's revolving credit facility and proceeds from the issuance of ENP common units to the public. As previously discussed, the acquisition was accounted for as a transaction between entities under common control. Therefore, the assets and liabilities of the acquired properties were recorded at Encore Operating's carrying value as of May 31, 2009 of approximately $31.9 million and $1.3 million, respectively, and the historical financial information of ENP was recast to include the Williston Basin Assets for all periods the properties were owned by Encore Operating. As the historical basis in the Williston Basin Assets is included in the accompanying Consolidated Balance Sheets, the cash purchase price was recorded as a deemed distribution when paid to EAC.

Vinegarone Assets

In May 2009, ENP acquired certain natural gas properties in the Vinegarone Field in Val Verde County, Texas (the "Vinegarone Assets") from an independent energy company for approximately $27.5 million in cash, which was financed through proceeds from the issuance of ENP common units to the public. The results of operations of the Vinegarone Assets are included with those of ENP from the date of acquisition forward.

Arkoma Basin Assets

In January 2009, ENP acquired the Arkoma Basin Assets from Encore Operating for approximately $46.4 million in cash, which was financed through borrowings under OLLC's revolving credit facility. As previously discussed, the acquisition was accounted for as a transaction between entities under common control. Therefore, the assets and liabilities of the acquired properties were recorded at Encore Operating's carrying value as of December 31, 2008 of approximately $18.1 million and $0.7 million, respectively, and the historical financial information of ENP was recast to include the Arkoma Basin Assets for all periods the properties were owned by Encore Operating. As the historical basis in the Arkoma Basin Assets is included in the accompanying Consolidated Balance Sheets, the cash purchase price was recorded as a deemed distribution when paid to EAC.

Permian and Williston Basin Assets

In February 2008, ENP acquired the Permian and Williston Basin Assets from Encore Operating for approximately $125.0 million in cash and the issuance of 6,884,776 ENP common units to Encore Operating. In determining the total purchase price, the common units were valued at $125.0 million. However, no accounting value was ascribed to the common units as the cash consideration exceeded Encore Operating's carrying value of the properties. The cash portion of the purchase price was financed through borrowings under OLLC's revolving credit facility. As previously discussed, the acquisition was accounted for as a transaction between entities under common control. Therefore, the assets and liabilities of the acquired properties were recorded at Encore Operating's carrying value as of December 31, 2007 of approximately $105.0 million and $5.1 million, respectively, and the historical financial information of ENP was recast to include the Permian and Williston Basin Assets for all periods the properties were owned by Encore Operating. As the historical basis in the Permian and Williston Basin Assets is included in the accompanying Consolidated Balance Sheets, the cash purchase price was recorded as a deemed distribution when paid to EAC.

In May 2008, ENP acquired an existing net profits interest in certain of its properties in the Permian Basin in West Texas from an independent energy company for 283,700 ENP common units, which were valued at approximately $5.8 million at the time of the acquisition.

Big Horn Basin Assets

In March 2007, EAC acquired certain oil and natural gas properties and related assets in the Big Horn Basin in Wyoming and Montana (the "Big Horn Basin Assets") from an independent energy company. Prior to closing, EAC assigned the rights and duties under the purchase and sale agreement relating to the Elk Basin Assets to ENP. The purchase price for the Elk Basin Assets was approximately $330.7 million in cash. The results of operations of the Big Horn Basin Assets are included with those of ENP from the date of acquisition forward.

ENP financed the acquisition of the Elk Basin Assets through a $93.7 million contribution from EAC, $120 million of borrowings under a subordinated credit agreement with EAP Operating, and borrowings under OLLC's revolving credit facility. Please read "Note 6. Long-Term Debt" for additional discussion of ENP's long-term debt.

The following unaudited pro forma condensed financial data for 2007 (in thousands, except per unit amounts) was derived from the historical financial statements of ENP and from the accounting records of the seller to give effect to the acquisition of the Elk Basin Assets as if it had occurred on January 1, 2007. The unaudited pro forma condensed financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the acquisition of the Elk Basin Assets taken place on January 1, 2007 and is not intended to be a projection of future results.

Pro forma total revenues	$ 197,408
Pro forma net income	$ 19,621
Pro forma net loss per common unit:	
Basic	$ (0.79)
Diluted	$ (0.79)

Note 4. Commitments and Contingencies

Litigation

ENP is a party to ongoing legal proceedings in the ordinary course of business. The General Partner's management does not believe the result of these proceedings will have a material adverse effect on ENP's business, financial position, results of operations, liquidity, or ability to pay distributions.

Leases

ENP leases equipment that have non-cancelable lease terms in excess of one year. The following table summarizes by year the remaining non-cancelable future payments under these operating leases as of December 31, 2009 (in thousands):

2010	$ 687
2011	687
2012	514
2013	—
2014	—
Thereafter	—
	$ 1,888

ENP's operating lease rental expense was approximately $1.1 million, $1.0 million, and $1.1 million in 2009, 2008, and 2007, respectively.

Note 5. Asset Retirement Obligations

Asset retirement obligations relate to future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal. The following table summarizes the changes in ENP's asset retirement obligations for the periods indicated:

	Year Ended December 31,	
	2009	2008
	(In thousands)	
Future abandonment liability at January 1	$ 12,376	$ 11,254
Acquisition of properties	67	—
Wells drilled	22	104
Accretion of discount	709	538
Plugging and abandonment costs incurred	(164)	(62)
Revision of previous estimates	120	542
Future abandonment liability at December 31	$ 13,130	$ 12,376

As of December 31, 2009, $12.6 million of ENP's asset retirement obligations were long-term and recorded in "Future abandonment cost, net of current portion" and $0.6 million were current and included in "Other current liabilities" in the accompanying Consolidated Balance Sheets. Approximately $4.7 million of the long-term future abandonment liability represents the estimated cost for decommissioning the Elk Basin natural gas processing plant.

Note 6. Long-Term Debt

Revolving Credit Facility

OLLC is a party to a five-year credit agreement dated March 7, 2007 (as amended, the "OLLC Credit Agreement"). The OLLC Credit Agreement matures on March 7, 2012. In March 2009, OLLC amended the OLLC Credit Agreement to, among other things, increase the interest rate margins and commitment fees applicable to loans made under the OLLC Credit Agreement. In August 2009, OLLC amended the OLLC Credit Agreement to, among other things, (1) increase the borrowing base from $240 million to $375 million, (2) increase the aggregate commitments of the lenders from $300 million to $475 million, and (3) increase the interest rate margins and commitment fees applicable to loans made under the OLLC Credit Agreement. In November 2009, OLLC amended the OLLC Credit Agreement, which will be effective upon the closing of the Merger, to, among other things, permit the consummation of the Merger from being a "Change of Control" under the OLLC Credit Agreement.

The OLLC Credit Agreement provides for revolving credit loans to be made to OLLC from time to time and letters of credit to be issued from time to time for the account of OLLC or any of its restricted subsidiaries. The aggregate amount of the commitments of the lenders under the OLLC Credit Agreement is $475 million. Availability under the OLLC Credit Agreement is subject to a borrowing base, which is redetermined semi-annually and upon requested special redeterminations. As of December 31, 2009, the borrowing base was $375 million and there were $255 million of outstanding borrowings and $120 million of borrowing capacity under the OLLC Credit Agreement.

OLLC incurs a commitment fee of 0.5 percent on the unused portion of the OLLC Credit Agreement.

Obligations under the OLLC Credit Agreement are secured by a first-priority security interest in substantially all of OLLC's proved oil and natural gas reserves and in the equity interests of OLLC and its restricted subsidiaries. In addition, obligations under the OLLC Credit Agreement are guaranteed by ENP and OLLC's restricted subsidiaries. Obligations under the OLLC Credit Agreement are non-recourse to EAC and its restricted subsidiaries.

Loans under the OLLC Credit Agreement are subject to varying rates of interest based on (1) amount outstanding in relation to the borrowing base and (2) whether the loan is a Eurodollar loan or a base rate loan. Eurodollar loans under the OLLC Credit Agreement bear interest at the Eurodollar rate plus the applicable margin indicated in the following table, and base rate loans under the OLLC Credit Agreement bear interest at the base rate plus the applicable margin indicated in the following table:

Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans
Less than .50 to 1	2.250%	1.250%
Greater than or equal to .50 to 1 but less than .75 to 1	2.500%	1.500%
Greater than or equal to .75 to 1 but less than .90 to 1	2.750%	1.750%
Greater than or equal to .90 to 1	3.000%	2.000%

The "Eurodollar rate" for any interest period (either one, two, three, or six months, as selected by ENP) is the rate equal to the British Bankers Association London Interbank Offered Rate ("LIBOR") for deposits in dollars for a similar interest period. The "Base Rate" is calculated as the highest of: (1) the annual rate of interest announced by Bank of America, N.A. as its "prime rate"; (2) the federal funds effective rate plus 0.5 percent; or (3) except during a "LIBOR Unavailability Period," the Eurodollar rate (for dollar deposits for a one-month term) for such day plus 1.0 percent.

Any outstanding letters of credit reduce the availability under the OLLC Credit Agreement. Borrowings under the OLLC Credit Agreement may be repaid from time to time without penalty.

The OLLC Credit Agreement contains covenants including, among others, the following:

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against purchasing or redeeming capital stock, or prepaying indebtedness, subject to permitted exceptions;
- a restriction on creating liens on the assets of ENP, OLLC, and OLLC's restricted subsidiaries, subject to permitted exceptions;
- restrictions on merging and selling assets outside the ordinary course of business;
- restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business;
- a provision limiting oil and natural gas hedging transactions (other than puts) to a volume not exceeding 75 percent of anticipated production from proved producing reserves;
- a requirement that ENP and OLLC maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0;
- a requirement that ENP and OLLC maintain a ratio of consolidated EBITDA to the sum of consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0; and
- a requirement that ENP and OLLC maintain a ratio of consolidated funded debt to consolidated adjusted EBITDA of not more than 3.5 to 1.0.

As of December 31, 2009, ENP and OLLC were in compliance with all covenants of the OLLC Credit Agreement.

The OLLC Credit Agreement contains customary events of default including, among others, the following:

- failure to pay principal on any loan when due;
- failure to pay accrued interest on any loan or fees when due and such failure continues for more than three days;
- failure to observe or perform covenants and agreements contained in the OLLC Credit Agreement, subject in some cases to a 30-day grace period after discovery or notice of such failure;
- failure to make a payment when due on any other debt in a principal amount equal to or greater than $3 million or any other event or condition occurs which results in the acceleration of such debt or entitles the holder of such debt to accelerate the maturity of such debt;
- the commencement of liquidation, reorganization, or similar proceedings with respect to OLLC or any guarantor under bankruptcy or insolvency law, or the failure of OLLC or any guarantor generally to pay its debts as they become due;
- the entry of one or more judgments in excess of $3 million (to the extent not covered by insurance) and such judgment(s) remain unsatisfied and unstayed for 30 days;
- the occurrence of certain ERISA events involving an amount in excess of $3 million;
- there cease to exist liens covering at least 80 percent of the borrowing base properties; or
- the occurrence of a change in control.

If an event of default occurs and is continuing, lenders with a majority of the aggregate commitments may require Bank of America, N.A. to declare all amounts outstanding under the OLLC Credit Agreement to be immediately due and payable.

Subordinated Credit Agreement

In March 2007, OLLC entered into a six-year subordinated credit agreement with EAP Operating pursuant to which a single subordinated term loan was made to ENP in the aggregate amount of $120 million. The total outstanding balance of $126.4 million, including accrued interest, was repaid in September 2007 using a portion of the net proceeds from the IPO at which point the credit agreement was terminated.

Long-Term Debt Maturities

The following table shows ENP's long-term debt maturities as of December 31, 2009:

	Payments Due by Period						
	Total	2010	2011	2012	2013	2014	Thereafter
	(In thousands)						
Revolving credit facility	$ 255,000	$ —	$ —	$ 255,000	$ —	$ —	$ —

During 2009, 2008, and 2007, the weighted average interest rate for total indebtedness was 5.0 percent, 4.8 percent, and 8.9 percent, respectively.

Note 7. Partners' Equity and Distributions

Distributions

ENP's partnership agreement requires that, within 45 days after the end of each quarter, it distribute all of its available cash (as defined in ENP's partnership agreement) to its unitholders. Distributions are not cumulative. ENP distributes available cash to its unitholders in accordance with their ownership percentages.

The following table provides information regarding ENP's distributions of available cash for the periods indicated:

	Date Declared	Cash Distribution Declared per Common Unit	Date Paid	Total Distribution
		(In thousands)		
2009				
Quarter ended December 31	1/25/2010	$ 0.5375	2/12/2010	$ 24,642
Quarter ended September 30	10/26/2009	$ 0.5375	11/13/2009	24,642
Quarter ended June 30	7/27/2009	$ 0.5125	8/14/2009	23,481
Quarter ended March 31	4/27/2009	$ 0.5000	5/15/2009	16,813
2008				
Quarter ended December 31	1/26/2009	$ 0.5000	2/13/2009	16,813
Quarter ended September 30	11/7/2008	$ 0.6600	11/14/2008	22,191
Quarter ended June 30	8/11/2008	$ 0.6881	8/14/2008	23,119
Quarter ended March 31	5/9/2008	$ 0.5755	5/15/2008	19,316
2007				
Quarter ended December 31	2/6/2008	$ 0.3875	2/14/2008	9,843
Quarter ended September 30	11/8/2007	$ 0.0530(a)	11/14/2007	1,346

(a) Based on an initial quarterly distribution of $0.35 per unit, prorated for the period from and including September 17, 2007 (the closing date of the IPO) through September 30, 2007.

Shelf Registration Statement on Form S-3

In November 2008, ENP's "shelf" registration statement on Form S-3 was declared effective by the SEC. Under the shelf registration statement, ENP may offer common units, senior debt, or subordinated debt in one or more offerings with a total initial offering price of up to $1 billion.

Public Offerings of Common Units

In July 2009, ENP issued 9,430,000 common units under its shelf registration statement at a price to the public of $14.30 per common unit. ENP used the net proceeds of approximately $129.2 million, after deducting the underwriters' discounts and commissions of $5.4 million, in the aggregate, and offering costs of approximately $0.2 million, to fund a portion of the purchase price of the Rockies and Permian Basin Assets.

In May 2009, ENP issued 2,760,000 common units under its shelf registration statement at a price to the public of $15.60 per common unit. ENP used the net proceeds of approximately $40.9 million, after deducting the underwriters' discounts and commissions of $1.9 million, in the aggregate, and offering costs of approximately $0.2 million, to fund the purchase price of the Vinegarone Assets and a portion of the purchase price of the Williston Basin Assets.

Note 8. Earnings Per Unit

As discussed in "Note 2. Summary of Significant Accounting Policies," ENP adopted ASC 260-10 on January 1, 2009 and all periods prior to adoption have been restated to calculate earnings per unit in accordance therewith. For 2008, basic earnings per unit and diluted earnings per unit were unaffected by the adoption of ASC 260-10. For 2007, basic earnings per unit and diluted earnings per unit each decreased $0.01 per common unit as a result of the adoption of ASC 260-10. For 2007, earnings per unit was calculated based on the net loss for the period from the closing of the IPO in September 2007 through December 31, 2007.

The following table reflects the allocation of net income (loss) to ENP's limited partners and earnings per unit computations for the periods indicated:

	Year Ended December 31,		
	2009	2008	2007
	(In thousands, except per unit amounts)		
Net income (loss)	$ (40,329)	$ 220,756	$ 21,706
Less: net income for pre-IPO and pre-partnership operations of assets acquired from affiliates	(176)	(51,640)	(40,682)
Net income (loss) attributable to unitholders	$ (40,505)	$ 169,116	$ (18,976)
Numerator:			
Numerator for basic EPU:			
Net income (loss) attributable to unitholders	$ (40,505)	$ 169,116	$ (18,976)
Less: distributions earned by participating securities	(1,054)	(4,498)	(517)
Plus: cash distributions in excess of (less than) income allocated to the general partner	1,646	(1,548)	616
Net income (loss) allocated to limited partners	(39,913)	163,070	(18,877)
Plus: income allocated to dilutive participating securities	—	3,398	—
Numerator for diluted EPU	$ (39,913)	$ 166,468	$ (18,877)
Denominator:			
Denominator for basic EPU:			
Weighted average common units outstanding	39,366	30,568	23,877
Effect of dilutive management incentive units(a)	—	1,367	—
Effect of dilutive phantom units(b)	—	3	—
Denominator for diluted EPU	39,366	31,938	23,877
Net income (loss) per common unit:			
Basic	$ (1.01)	$ 5.33	$ (0.79)
Diluted	$ (1.01)	$ 5.21	$ (0.79)

(a) For 2007, 550,000 management incentive units were outstanding but were excluded from the diluted earnings per unit calculations because their effect would have been antidilutive. Please read "Note 9. Unit-Based Compensation Plans" for additional discussion of the management incentive units.

(b) Unvested phantom units have no contractual obligation to absorb losses of ENP. Therefore, for 2009 and 2007, 56,250 and 20,000 phantom units, respectively, were outstanding but were excluded from the diluted earnings per unit calculations because their effect would have been antidilutive. Please read "Note 9. Unit-Based Compensation Plans" for additional discussion of phantom units.

Note 9. Unit-Based Compensation Plans

Management Incentive Units

In May 2007, the board of directors of the General Partner issued 550,000 management incentive units to certain executive officers of the General Partner. During the fourth quarter of 2008, the management incentive units became convertible into ENP common units, at the option of the holder, at a ratio of one management incentive unit to approximately 3.1186 ENP common units, and all 550,000 management incentive units were converted into 1,715,205 ENP common units.

The fair value of the management incentive units was estimated on the date of grant using a discounted dividend model. During 2008 and 2007, ENP recognized non-cash unit-based compensation expense for the management incentive units of approximately $4.8 million and $6.8 million, respectively, which is included in "General and administrative expense" in the accompanying Consolidated Statements of Operations. There have been no additional issuances of management incentive units.

Long-Term Incentive Plan

In September 2007, the board of directors of the General Partner adopted the LTIP, which provides for the granting of options, restricted units, phantom units, unit appreciation rights, distribution equivalent rights, other unit-based awards, and unit awards. All employees, consultants, and directors of EAC, the General Partner, and any of their subsidiaries and affiliates who perform services for ENP are eligible to be granted awards under the LTIP. The LTIP is administered by the board of directors of the General Partner or a committee thereof, referred to as the plan administrator. To satisfy common unit awards under the LTIP, ENP may issue common units, acquire common units in the open market, or use common units owned by EAC.

The total number of common units reserved for issuance pursuant to the LTIP is 1,150,000. As of December 31, 2009, there were 1,075,000 common units available for issuance under the LTIP.

Phantom Units. Each October, ENP issues 5,000 phantom units to each member of the General Partner's board of directors pursuant to the LTIP. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit or, at the discretion of the plan administrator, cash equivalent to the value of a common unit. ENP intends to settle the phantom units at vesting by issuing common units to the grantee; therefore, these phantom units are classified as equity instruments. Phantom units vest equally over a four-year period. The holders of phantom units also receive distribution equivalent rights prior to vesting, which entitle them to receive cash equal to the amount of any cash distributions paid by ENP with respect to a common unit during the period the right is outstanding. During 2009, 2008, and 2007, ENP recognized non-cash unit-based compensation expense for the phantom units of approximately $0.4 million, $0.3 million, and $31,000, respectively, which is included in "General and administrative expense" in the accompanying Consolidated Statements of Operations.

The following table summarizes the changes in ENP's unvested phantom units for 2009:

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2009	43,750	$ 18.67
Granted	25,000	18.13
Vested	(12,500)	18.83
Forfeited	—	—
Outstanding at December 31, 2009	56,250	18.40

During 2009, 2008, and 2007, ENP issued 25,000, 30,000, and 20,000, respectively, phantom units to members of the General Partner's board of directors, the vesting of which is dependent only on the passage of time and continuation as a board member. The following table provides information regarding ENP's outstanding phantom units at December 31, 2009:

	Year of Vesting				
Year of Grant	2010	2011	2012	2013	Total
2007	5,000	5,000	—	—	10,000
2008	7,500	7,500	6,250	—	21,250
2009	6,250	6,250	6,250	6,250	25,000
Total	18,750	18,750	12,500	6,250	56,250

As of December 31, 2009, ENP had $0.7 million of total unrecognized compensation cost related to unvested phantom units, which is expected to be recognized over a weighted average period of 2.2 years. During 2009 and 2008, there were 12,500 and 6,250, respectively, phantom units that vested, the total fair value of which was $0.2 million and $0.1 million, respectively.

Note 10. Fair Value Measurements

The following table sets forth ENP's book value and estimated fair value of financial instruments as of the dates indicated:

	December 31,			
	2009		2008	
	Book Value	Book Value	Book Value	Book Value
	(In thousands)			
Assets:				
Cash and cash equivalents	$ 1,754	$ 1,754	$ 619	$ 619
Accounts receivable — trade	24,543	24,543	18,965	18,965
Accounts receivable — affiliate	8,213	8,213	3,896	3,896
Commodity derivative contracts	26,304	26,304	113,628	113,628
Liabilities:				
Accounts payable — trade	577	577	1,036	1,036
Accounts payable — affiliate	2,780	2,780	5,468	5,468
Revolving credit facility	255,000	255,000	150,000	150,000
Commodity derivative contracts	19,547	19,547	229	229
Interest rate swaps	3,669	3,669	4,559	4,559

The book values of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term nature of these instruments. The book value of the revolving credit facility approximates fair value as the interest rate is variable. ENP's credit risk has not changed materially from the date the revolving credit facility was entered into. Commodity derivative contracts and interest rate swaps are marked-to-market each period and are thus stated at fair value in the accompanying Consolidated Balance Sheets.

Commodity Derivative Contracts

ENP manages commodity price risk with swap contracts, put contracts, collars, and floor spreads. Swap contracts provide a fixed price for a notional amount of sales volumes. Put contracts provide a fixed floor price on a notional amount of sales volumes while allowing full price participation if the relevant index price closes above the floor price. Collars provide a floor price for a notional amount of sales volumes while allowing some additional price participation if the relevant index price closes above the floor price.

From time to time, ENP enters into floor spreads. In a floor spread, ENP purchases puts at a specified price (a "purchased put") and also sells a put at a lower price (a "short put"). This strategy enables ENP to achieve some downside protection for a portion of its production, while funding the cost of such protection by selling a put at a lower price. If the price of the commodity falls below the strike price of the purchased put, then ENP has protection against additional commodity price decreases for the covered production down to the strike price of the short put. At commodity prices below the strike price of the short put, the benefit from the purchased put is generally offset by the expense associated with the short put. For example, in 2007, ENP purchased oil put options for 2,000 Bbls/D in 2010 at $65 per Bbl. As NYMEX prices increased in 2008, ENP wanted to protect downside price exposure at the higher price. In order to do this, ENP purchased oil put options for 2,000 Bbls/D in 2010 at $75 per Bbl and simultaneously sold oil put options for 2,000 Bbls/D in 2010 at $65 per Bbl. Thus, after these transactions were completed, ENP had purchased two oil put options for 2,000 Bbls/D in 2010 (one at $65 per Bbl and one at $75 per Bbl) and sold one oil put option for 2,000 Bbls/D in 2010 at $65 per Bbl. However, the net effect resulted in ENP owning one oil put option for 2,000 Bbls/D at $75 per Bbl. In the following tables, the purchased floor component of these floor spreads are shown net and included with ENP's other floor contracts.

The following tables summarize ENP's open commodity derivative contracts as of December 31, 2009:

Oil Derivative Contracts

Period	Average Daily Floor Volume	Weighted Average Floor Price	Average Daily Cap Volume	Weighted Average Cap Price	Average Daily Swap Volume	Weighted Average Swap Price	Asset (Liability) Fair Market Volume
	(Bbls)	(per Bbl)	(Bbls)	(per Bbl)	(Bbls)	(per Bbl)	(in thousands)
2010							$ (1,476)
	880	$ 80.00	440	$ 93.80	760	$ 75.43	
	2,000	75.00	1,000	77.23	250	65.95	
	760	67.00	—	—	—	—	
2011							2,638
	1,880	80.00	1,440	95.41	760	78.46	
	1,000	70.00	—	—	—	—	
	760	65.00	—	—	250	69.65	
2012							(5,020)
	750	70.00	500	82.05	210	81.62	
	1,510	65.00	250	79.25	1,300	76.54	
							$ (3,858)

Natural Gas Derivative Contracts

Period	Average Daily Floor Volume	Weighted Average Floor Price	Average Daily Cap Volume	Weighted Average Cap Price	Average Daily Swap Volume	Weighted Average Swap Price	Asset Fair Market Volume
	(Mcf)	(per Mcf)	(Mcf)	(per Mcf)	(Mcf)	(per Mcf)	(in thousands)
2010							$ 7,963
	3,800	$ 8.20	3,800	$ 9.58	5,452	$ 6.20	
	4,698	7.26	—	—	550	5.86	
2011							2,105
	3,398	6.31	—	—	7,952	6.36	
	—	—	—	—	550	5.86	
2012							547
	898	6.76	—	—	5,452	6.26	
	—	—	—	—	550	5.86	
							$ 10,615

Counterparty Risk. At December 31, 2009, ENP had committed 10 percent or greater (in terms of fair market value) of either its oil or natural gas derivative contracts in asset positions to the following counterparties:

Counterparty	Fair Market Value of Oil Derivative Contracts Committed	Fair Market Value of Natural Gas Derivative Contracts Committed
	(In thousands)	
BNP Paribas	$ 13,955	$ 2,795
Calyon	3,820	6,167
Royal Bank of Canada	4,158	(a)
Wachovia	3,069	1,148

(a) Less than 10 percent.

In order to mitigate the credit risk of financial instruments, ENP enters into master netting agreements with certain counterparties. The master netting agreement is a standardized, bilateral contract between a given counterparty and ENP. Instead of treating each financial transaction between the counterparty and ENP separately, the master netting agreement enables the counterparty and ENP to aggregate all financial trades and treat them as a single agreement. This arrangement is intended to benefit ENP in three ways: (1) the netting of the value of all trades reduces the likelihood of counterparties requiring daily collateral posting by ENP; (2) default by a counterparty under one financial trade can trigger rights to terminate all financial trades with such counterparty; and (3) netting of settlement amounts reduces ENP's credit exposure to a given counterparty in the event of close-out. ENP's accounting policy is to not offset fair value amounts for derivative instruments.

Interest Rate Swaps

ENP uses derivative instruments in the form of interest rate swaps, which hedge risk related to interest rate fluctuation, whereby it converts the interest due on certain floating rate debt under its revolving credit facility to a weighted average fixed rate. The following table summarizes ENP's open interest rate swaps as of December 31, 2009, all of which were entered into with Bank of America, N.A.:

Term	Notional Amount	Fixed Rate	Floating Rate
	(In thousands)		
Jan. 2010 — Jan. 2011	$ 50,000	3.1610%	1-month LIBOR
Jan. 2010 — Jan. 2011	25,000	2.9650%	1-month LIBOR
Jan. 2010 — Jan. 2011	25,000	2.9613%	1-month LIBOR
Jan. 2010 — Mar. 2012	50,000	2.4200%	1-month LIBOR

During 2009 and 2008, settlements of interest rate swaps increased ENP's interest expense by approximately $3.8 million and $0.2 million, respectively.

Current Period Impact

ENP recognizes derivative fair value gains and losses related to: (1) ineffectiveness on derivative contracts designated as hedges; (2) changes in the fair market value of derivative contracts not designated as hedges; (3) settlements on derivative contracts not designated as hedges; and (4) premium amortization. The following table summarizes the components of "Derivative fair value loss (gain)" for the periods indicated:

	Year Ended December 31,		
	2009	2008	2007
	(In thousands)		
Ineffectiveness	$ 2	$ 372	$ —
Mark-to-market loss (gain)	94,438	(101,595)	23,470
Premium amortization	23,245	8,936	4,073
Settlements	(70,221)	(4,593)	(1,242)
Total derivative fair value loss (gain)	$ 47,464	$ (96,880)	$ 26,301

Accumulated Other Comprehensive Loss

At December 31, 2009 and 2008, "Accumulated other comprehensive loss" on the accompanying Consolidated Balance Sheets consisted entirely of deferred losses, net of tax, on ENP's interest rate swaps of $3.4 million and $4.3 million, respectively. During 2010, ENP expects to reclassify $3.4 million of deferred losses from accumulated other comprehensive loss to interest expense. The actual gains or losses ENP will realize from its interest rate swaps may vary significantly from the deferred losses recorded in "Accumulated other comprehensive loss" in the accompanying Consolidated Balance Sheet due to the fluctuation of interest rates.

Tabular Disclosures of Fair Value Measurements

The following table summarizes the fair value of ENP's derivative contracts as of the dates indicated (in thousands):

	Asset Derivatives				Liability Derivatives			
	December 31, 2009		December 31, 2008		December 31, 2009		December 31, 2008	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives not designated as hedging instruments under ASC 815								
Commodity derivative contracts	Derivatives — current	$ 12,881	Derivatives — current	$ 75,131	Derivatives — current	$ 6,393	Derivatives — current	$ —
Commodity derivative contracts	Derivatives — noncurrent	13,423	Derivatives — noncurrent	38,497	Derivatives — noncurrent	13,154	Derivatives — noncurrent	229
Total derivatives not designated as hedging instruments under ASC 815		$ 26,304		$ 113,628		$ 19,547		$ 229
Derivatives designated as hedging instruments under ASC 815								
Interest rate swaps	Derivatives — current	$ —	Derivatives — current	$ —	Derivatives — current	$ 3,421	Derivatives — current	$ 1,297
Interest rate swaps	Derivatives — noncurrent	—	Derivatives — noncurrent	—	Derivatives — noncurrent	248	Derivatives — noncurrent	3,262
Total derivatives designated as hedging instruments under ASC 815		$ —		$ —		$ 3,669		$ 4,559
Total derivatives		$ 26,304		$ 113,628		$ 23,216		$ 4,788

The following table summarizes the effect of derivative instruments not designated as hedges under ASC 815 on the Consolidated Statements of Operations for the periods indicated (in thousands):

Derivatives Not Designated as Hedges Under ASC 815	Location of Loss (Gain) Recognized in Income	Amount of Loss (Gain) Recognized in Income Year Ended December 31, 2009	2008	2007
Commodity derivative contracts	Derivative fair value loss (gain)	$ 47,462	$ (97,252)	$ 26,301

The following tables summarize the effect of derivative instruments designated as hedges under ASC 815 on the Consolidated Statements of Operations for the periods indicated (in thousands):

Derivatives Designated as Hedges Under ASC 815	Amount of Loss Recognized in Accumulated OCI (Effective Portion) Year Ended December 31, 2009	2008	2007
Interest rate swaps	$ 2,946	$ 4,505	$ —

Location of Loss Reclassified from Accumulated OCI into Income (Effective Portion)	Amount of Loss Reclassified from Accumulated OCI into Income (Effective Portion) Year Ended December 31, 2009	2008	2007
Interest expense	$ 3,785	$ 246	$ —

Location of Loss Recognized in Income as Ineffective	Amount of Loss Recognized in Income as Ineffective Year Ended December 31, 2009	2008	2007
Derivative fair value loss (gain)	$ 2	$ 372	$ —

Fair Value Hierarchy

ASC 820-10 established a fair value hierarchy that prioritizes the inputs used to measure fair value. The three levels of the fair value hierarchy defined by ASC 820-10 are as follows:

- Level 1 — Unadjusted quoted prices are available in active markets for identical assets or liabilities.
- Level 2 — Pricing inputs, other than quoted prices within Level 1, that are either directly or indirectly observable.
- Level 3 — Pricing inputs that are unobservable requiring the use of valuation methodologies that result in management's best estimate of fair value.

ENP's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the financial assets and liabilities and their placement within the fair value hierarchy levels. The following methods and assumptions were used to estimate the fair values of ENP's assets and liabilities that are accounted for at fair value on a recurring basis:

- Level 2 — Fair values of oil and natural gas swaps were estimated using a combined income-based and market-based valuation methodology based upon forward commodity price curves obtained from independent pricing services reflecting broker market quotes. Fair values of interest rate swaps were estimated using a combined income-based and market-based valuation methodology based upon credit ratings and forward interest rate yield curves obtained from independent pricing services reflecting broker market quotes.
- Level 3 — ENP's oil and natural gas calls, puts, and short puts are average value options, which are not exchange-traded contracts. Settlement is determined by the average underlying price over a predetermined period of time. ENP uses both observable and unobservable inputs in a Black-Scholes valuation model to determine fair value. Accordingly, these derivative instruments are classified within the Level 3 valuation hierarchy. The observable inputs of ENP's valuation model include: (1) current market and contractual prices for the underlying instruments; (2) quoted forward prices for oil and natural gas; and (3) interest rates, such as a LIBOR curve for a term similar to the commodity derivative contract. The unobservable input of ENP's valuation model is volatility. The implied volatilities for ENP's calls, puts, and short puts with comparable strike prices are based on the settlement values from certain exchange-traded contracts. The implied volatilities for calls, puts, and short puts where there are no exchange-traded contracts with the same strike price are extrapolated from exchange-traded implied volatilities by an independent party.

ENP adjusts the valuations from the valuation model for nonperformance risk, using management's estimate of the counterparty's credit quality for asset positions and ENP's credit quality for liability positions. ENP uses multiple sources of third-party credit data in determining counterparty nonperformance risk, including credit default swaps. ENP considers the impact of netting and offset provisions in the agreements on counterparty credit risk, including whether the position with the counterparty is a net asset or net liability. There were no changes in the valuation techniques used to measure the fair value of ENP's oil and natural gas calls, puts, or short puts during 2009.

The following table sets forth ENP's assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2009:

	Fair Value Measurements at Reporting Date Using			
	Asset (Liability) at December 31, 2009	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(In thousands)		
Oil derivative contracts — swaps	$ (12,443)	$ —	$ (12,443)	$ —
Oil derivative contracts — floors and caps	8,585	—	—	8,585
Natural gas derivative contracts — swaps	2,087	—	2,087	—
Natural gas derivative contracts — floors and caps	8,528	—	—	8,528
Interest rate swaps	(3,669)	—	(3,669)	—
Total	$ 3,088	$ —	$ (14,025)	$ 17,113

The following table summarizes the changes in the fair value of ENP's Level 3 assets and liabilities for 2009:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Oil Derivative Contracts – Floors and Caps	Natural Gas Derivative Contracts – Floors and Caps	Total
		(In thousands)	
Balance at January 1, 2009	$ 95,430	$ 12,741	$ 108,171
Total gains (losses):			
Included in earnings	(32,249)	8,940	(23,309)
Settlements	(54,596)	(13,153)	(67,749)
Balance at December 31, 2009	$ 8,585	$ 8,528	$ 17,113
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 the reporting date	$ (32,249)	$ 8,940	$ (23,309)

Since ENP does not use hedge accounting for its commodity derivative contracts, all gains and losses on its Level 3 assets and liabilities are included in "Derivative fair value loss (gain)" in the accompanying Consolidated Statements of Operations.

All fair values have been adjusted for nonperformance risk resulting in a reduction of the net commodity derivative asset of approximately $0.1 million as of December 31, 2009. For commodity derivative contracts which are in an asset position, ENP uses the counterparty's credit default swap rating. For commodity derivative contracts which are in a liability position, ENP uses the average credit default swap rating of its peer companies as ENP does not have its own credit default swap rating.

ENP's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the nonfinancial assets and liabilities and their placement within the fair value hierarchy levels. The following methods and assumptions were used to estimate the fair values of ENP's assets and liabilities that are accounted for at fair value on a nonrecurring basis:

- Level 3 — Fair values of asset retirement obligations are determined using discounted cash flow methodologies based on inputs, such as plugging costs and reserve lives, which are not readily available in public markets. Please read “Note 5. Asset Retirement Obligations” for additional discussion of ENP’s asset retirement obligations.

The following table sets forth ENP’s assets and liabilities that were accounted for at fair value on a nonrecurring basis as of December 31, 2009:

Description	Liability at December 31, 2009	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Gains (Losses)
			(In thousands)		
Asset					
Retirement obligations	$ 89	$ —	$ —	$ 89	$ —

Note 11. Related Party Transactions

Administrative Services Agreement

ENP does not have any employees. The employees supporting ENP’s operations are employees of EAC. As discussed in “Note 1. Formation of the Partnership and Description of Business,” ENP entered into the Administrative Services Agreement pursuant to which Encore Operating performs administrative services for ENP, such as accounting, corporate development, finance, land, legal, and engineering. In addition, Encore Operating provides all personnel, facilities, goods, and equipment necessary to perform these services which are not otherwise provided for by ENP. Encore Operating is not liable to ENP for its performance of, or failure to perform, services under the Administrative Services Agreement unless its acts or omissions constitute gross negligence or willful misconduct.

Encore Operating initially received an administrative fee of $1.75 per BOE of ENP’s production for such services. From April 1, 2008 to March 31, 2009, the administration fee was $1.88 per BOE of ENP’s production. Effective April 1, 2009, the administrative fee increased to $2.02 per BOE of ENP’s production. ENP also reimburses Encore Operating for actual third-party expenses incurred on ENP’s behalf. Encore Operating has substantial discretion in determining which third-party expenses to incur on ENP’s behalf. In addition, Encore Operating is entitled to retain any COPAS overhead charges associated with drilling and operating wells that would otherwise be paid by non-operating interest owners to the operator.

The administrative fee will increase in the following circumstances:

- beginning on the first day of April in each year by an amount equal to the product of the then-current administrative fee multiplied by the COPAS Wage Index Adjustment for that year;

- if ENP acquires additional assets, Encore Operating may propose an increase in its administrative fee that covers the provision of services for such additional assets; however, such proposal must be approved by the board of directors of the General Partner upon the recommendation of its conflicts committee; and

- otherwise as agreed upon by Encore Operating and the General Partner, with the approval of the conflicts committee of the board of directors of the General Partner.

ENP reimburses EAC for any state income, franchise, or similar tax incurred by EAC resulting from the inclusion of ENP in consolidated tax returns with EAC as required by applicable law. The amount of any such reimbursement is limited to the tax that ENP would have incurred had it not been included in a combined group with EAC.

Administrative fees (including COPAS recovery) paid to Encore Operating pursuant to the Administrative Services Agreement are included in "General and administrative expenses" in the accompanying Consolidated Statement of Operations. The reimbursements of actual third-party expenses incurred by Encore Operating on ENP's behalf are included in "Lease operating expense" in the accompanying Consolidated Statement of Operations. The following table shows amounts paid by ENP to Encore Operating pursuant to the Administrative Services Agreement for the periods indicated:

	Year Ended December 31,		
	2009	2008	2007
	(In thousands)		
Administrative fees (including COPAS recovery)	$ 5,693	$ 6,600	$ 2,848
Third-party expenses	5,352	8,269	3,502

As of December 31, 2009 and 2008, ENP had a payable to EAC of $2.8 million and $5.5 million, respectively, which is reflected as "Accounts payable — affiliate" in the accompanying Consolidated Balance Sheets and a receivable from EAC of $8.2 million and $3.9 million, respectively, which is reflected as "Accounts receivable — affiliate" in the accompanying Consolidated Balance Sheets.

Acquisitions from EAC

As previously discussed, ENP acquired (1) the Permian and Williston Basin Assets from Encore Operating in February 2008 for approximately $125.0 million in cash and the issuance of 6,884,776 ENP common units to Encore Operating, (2) the Arkoma Basin Assets from Encore Operating in January 2009 for approximately $46.4 million in cash, (3) the Williston Basin Assets from Encore Operating in June 2009 for approximately $25.2 million in cash, and (4) the Rockies and Permian Basin Assets from Encore Operating in August 2009 for approximately $179.6 million in cash. Prior to acquisition by ENP, these properties were owned by EAC and were not separate legal entities.

In addition to payroll-related expenses, EAC incurred general and administrative expenses related to leasing office space and other corporate overhead expenses during the period these properties were owned by EAC. A portion of EAC's consolidated general and administrative expenses were allocated to ENP and included in the accompanying Consolidated Statements of Operations based on the respective percentage of BOE produced by the properties in relation to the total BOE produced by EAC on a consolidated basis. A portion of EAC's consolidated indirect lease operating overhead expenses were allocated to ENP included in the accompanying Consolidated Statements of Operations based on its share of EAC's direct lease operating expense.

Distributions

During 2009, 2008, and 2007, ENP paid cash distributions of approximately $43.9 million, $46.9 million, and $0.8 million, respectively, to EAC and its subsidiaries, including the General Partner. During 2008 and 2007, ENP paid cash distributions of approximately $3.5 million and $27,000, respectively, to certain executive officers of the General Partner based on their ownership of management incentive units.

Other

As discussed in "Note 6. Long-Term Debt," during 2007, ENP had a subordinated credit agreement with EAP Operating, which was repaid in full with a portion of the net proceeds from the IPO.

EAC contributed $93.7 million in cash to ENP in March 2007. These proceeds were used by ENP, along with proceeds from the borrowings under ENP's long-term debt agreements, to purchase the Elk Basin Assets. Additionally, EAC made a non-cash contribution in March 2007 of derivative oil put contracts representing 2,500 Bbls/D of production at $65.00 per Bbl for the period of April 2007 through December 2008. At the date of transfer, the derivative contracts had a fair value of $9.4 million.

Note 12. Subsequent Events

Subsequent events were evaluated through February 24, 2010, which is the date the financial statements were issued.

On January 25, 2010, ENP announced that the board of directors of the General Partner declared an ENP cash distribution for the fourth quarter of 2009 to unitholders of record as of the close of business on February 8, 2010 at a rate of $0.5375 per unit. Approximately $24.6 million was paid to unitholders on February 12, 2010.

SUPPLEMENTARY INFORMATION

Capitalized Costs and Costs Incurred Relating to Oil and Natural Gas Producing Activities

The capitalized cost of oil and natural gas properties was as follows as of the dates indicated:

	December 31, 2009	December 31, 2008
	(In thousands)	
Properties and equipment, at cost — successful efforts method:		
Proved properties, including wells and related equipment	$ 851,833	$ 814,903
Unproved properties	55	84
Accumulated depletion, depreciation, and amortization	(210,417)	(154,584)
	$ 641,471	$ 660,403

The following table summarizes costs incurred related to oil and natural gas properties for the periods indicated:

	Year Ended December 31, 2009	2008	2007
	(In thousands)		
Acquisitions:			
Proved properties(a)	$ 32,265	$ 5,940	$ 498,057
Unproved properties	1	—	105
Total acquisitions	32,266	5,940	498,162
Development:			
Drilling and exploitation(b)	7,197	31,450	21,277
Total development	7,197	31,450	21,277
Exploration:			
Drilling and exploitation	1,088	8,104	9,899
Other	135	119	101
Total exploration	1,223	8,223	10,000
Total costs incurred	$ 40,686	$ 45,613	$ 529,439

(a) Includes asset retirement obligations incurred for acquisition activities of $66 thousand and $6.5 million in 2009 and 2007, respectively.

(b) Includes asset retirement obligations incurred for development activities of $23 thousand, $29 thousand, and $0.1 million during 2009, 2008, and 2007, respectively.

Oil & Natural Gas Producing Activities — Unaudited

The estimates of ENP's proved oil and natural gas reserves, which are located entirely within the United States, were prepared in accordance with guidelines established by the SEC. Proved oil and natural gas reserve quantities are derived from estimates prepared by Miller and Lents, Ltd., who are independent petroleum engineers.

Future prices received for production and future production costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. There can be no assurance that the proved reserves will be developed within the periods assumed or that prices and costs will remain constant. Actual production may not equal the estimated amounts used in the preparation of reserve projections. In accordance with SEC guidelines, 2009 estimates of future net cash flows from ENP's properties and the representative value thereof are made using an unweighted average of the closing oil and natural gas prices for the applicable commodity on the first day of each month in 2009 and are held constant throughout the life of the properties. In accordance with past SEC guidelines, 2008 and 2007 estimates of future net cash flows from ENP's properties and the representative value thereof are made using oil and natural gas prices in effect as of the dates of such estimates and are held constant throughout the life of the properties. Prices used in estimating ENP's future net cash flows were as follows:

	2009	2008	2007
Oil (per Bbl)	$ 61.18	$ 44.60	$ 96.01
Natural gas (per Mcf)	$ 3.83	$ 5.62	$ 7.47

Net future cash inflows have not been adjusted for commodity derivative contracts outstanding at the end of the year. Future cash inflows are reduced by estimated production and development costs, which are based on year-end economic conditions and held constant throughout the life of the properties, by estimated abandonment costs, net of salvage, and by the estimated effect of future income taxes due to the Texas margin tax. Future federal income taxes have not been deducted from future net revenues in the calculation of ENP's standardized measure as each partner is separately taxed on his share of ENP's taxable income.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures. Oil and natural gas reserve engineering is and must be recognized as a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in any exact way, and estimates of other engineers might differ materially from those included herein. The accuracy of any reserve estimate is a function of the quality of available data and engineering, and estimates may justify revisions based on the results of drilling, testing, and production activities. Accordingly, reserve estimates are often materially different from the quantities of oil and natural gas that are ultimately recovered. Reserve estimates are integral to management's analysis of impairments of oil and natural gas properties and the calculation of DD&A on these properties.

ENP's estimated net quantities of proved oil and natural gas reserves were as follows as of the dates indicated:

	December 31,		
	2009	2008	2007
Proved developed reserves:			
Oil (MBbls)	26,341	24,769	30,851
Natural gas (MMcf)	78,379	70,462	72,955
Combined (MBOE)	39,404	36,513	43,010
Proved undeveloped reserves:			
Oil (MBbls)	2,589	2,509	4,377
Natural gas (MMcf)	6,320	7,549	10,283
Combined (MBOE)	3,643	3,767	6,091
Proved reserves:			
Oil (MBbls)	28,930	27,278	35,228
Natural gas (MMcf)	84,699	78,011	83,238
Combined (MBOE)	43,047	40,280	49,101

The changes in ENP's proved reserves were as follows for the periods indicated:

	Oil (MBbls)	Natural Gas (MMcf)	Oil Equivalent (MBOE)
Balance, December 31, 2006(a)	9,073	76,824	21,877
Purchases of minerals-in-place	25,965	6,221	27,002
Extensions and discoveries	488	7,414	1,724
Revisions of previous estimates	1,934	(1,470)	1,688
Production	(2,232)	(5,751)	(3,190)
Balance, December 31, 2007(a)	35,228	83,238	49,101
Purchases of minerals-in-place	32	2,489	447
Extensions and discoveries	148	2,832	620
Revisions of previous estimates	(5,596)	(4,329)	(6,318)
Production	(2,534)	(6,219)	(3,570)
Balance, December 31, 2008(a)	27,278	78,011	40,280
Purchases of minerals-in-place	—	18,837	3,140
Extensions and discoveries	2	1,112	187
Revisions of previous estimates	3,987	(7,164)	2,793
Production	(2,337)	(6,097)	(3,353)
Balance, December 31, 2009	28,930	84,699	43,047

(a) Includes 1,585 MBOE, 1,510 MBOE, and 1,952 MBOE of proved reserves as of December 31, 2008, 2007, and 2006, respectively, associated with the Arkoma Basin Assets ENP acquired from Encore Operating in January 2009. Also includes 1,899 MBOE, 2,330 MBOE, and 444 MBOE of proved reserves as of December 31, 2008, 2007, and 2006, respectively, associated with the Williston Basin Assets ENP acquired from Encore Operating in June 2009. Also includes 10,732 MBOE, 13,663 MBOE, and 6,321 MBOE of proved reserves as of December 31, 2008, 2007, and 2006, respectively, associated with the Rockies and Permian Basin Assets ENP acquired from Encore Operating in August 2009. The acquisitions of these assets were accounted for as transactions between entities under common control, similar to a pooling of interests, whereby ENP's historical financial information and proved reserve volumes were recast to include the acquired properties for all periods the properties were owned by Encore Operating.

Recent SEC Rule-Making Activity. In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserves reporting requirements. Application of the new reserve rules resulted in the use of lower prices at December 31, 2009 for both oil and natural gas than would have resulted under the previous rules. Use of new 12-month average pricing rules at December 31, 2009 resulted in a decrease in proved reserves of approximately 2.2 MMBOE. Pursuant to the SEC's final rule, prior period reserves were not restated.

ENP's standardized measure of discounted estimated future net cash flows was as follows as of the dates indicated:

	December 31, 2009	December 31, 2008	December 31, 2007
	(In thousands)		
Future cash inflows	$ 1,879,504	$ 1,406,100	$ 3,392,199
Future production costs	(819,352)	(706,589)	(1,157,893)
Future development costs	(46,852)	(50,540)	(61,961)
Future abandonment costs, net of salvage	(29,339)	(28,771)	(27,750)
Future income tax expense	(1,217)	(182)	(7,344)
Future net cash flows	982,744	620,018	2,137,251
10% annual discount	(488,243)	(293,396)	(1,073,527)
Standardized measure of discounted estimated future net cash flows	$ 494,501	$ 326,622	$ 1,063,724

The changes in ENP's standardized measure of discounted estimated future net cash flows were as follows for the periods indicated:

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Net change in prices and production costs	$ 153,083	$ (660,592)	$ 145,074
Purchases of minerals-in-place	19,136	5,856	719,376
Extensions, discoveries, and improved recovery	1,588	5,938	28,692
Revisions of previous quantity estimates	65,300	(60,036)	46,995
Production, net of production costs	(95,270)	(76,970)	(161,737)
Previously estimated development costs incurred during the period	4,732	13,685	17,542
Accretion of discount	32,662	106,373	25,527
Change in estimated future development costs	(3,527)	(6,372)	(39,806)
Net change in income taxes	(457)	3,345	(2,427
Change in timing and other	(9,368)	(68,329)	29,225
Net change in standardized measure	167,879	(737,102)	808,461
Standardized measure, beginning of year	326,622	1,063,724	255,263
Standardized measure, end of year	$ 494,501	$ 326,622	$ 1,063,724

Selected Quarterly Financial Data — Unaudited

The following table provides selected quarterly financial data for the periods indicated:

	Quarter First	Quarter Second	Quarter Third	Quarter Fourth
	(In thousands, except per unit data)			
2009				
Revenues, as reported	$ 18,651	$ 27,246	$ 41,032	$ 46,560
Plus: revenues from assets acquired from affiliate	7,648	9,380	—	—
Revenues, as recast	$ 26,299	$ 36,626	$ 41,032	$ 46,560
Operating income (loss), as reported	$ 6,780	$ (35,043)	$ 10,383	$ (10,059)
Plus: operating income (loss) from assets acquired from affiliate	(2,492)	1,044	—	—
Operating income (loss), as recast	$ 4,288	$ (33,999)	$ 10,383	$ (10,059)
Net income (loss), as reported	$ 4,568	$ (37,593)	$ 7,460	$ (13,316)
Plus: net income (loss) from assets acquired from affiliate	(2,492)	1,044	—	—
Net income (loss), as recast	$ 2,076	$ (36,549)	$ 7,460	$ (13,316)
Net income (loss) allocation:				
Limited partners' interest in net income (loss)	$ 4,499	$ (37,093)	$ 5,904	$ (13,169)
General partner's interest in net income (loss)	$ 69	$ (630)	$ 63	$ (147)
Net income (loss) per common unit:				
Basic	$ 0.14	$ (1.08)	$ 0.13	$ (0.29)
Diluted	$ 0.14	$ (1.08)	$ 0.13	$ (0.29)
2008				
Revenues, as reported	$ 49,245	$ 67,160	$ 84,110	$ 26,383
Plus: revenues from assets acquired from affiliate	23,377	24,312	—	11,294
Revenues, as recast	$ 72,622	$ 91,472	$ 84,110	$ 37,677
Operating income (loss), as reported	$ 7,291	$ (38,817)	$ 113,981	$ 120,278
Plus: operating income from assets acquired from affiliate	11,464	13,810	—	381
Operating income (loss)	$ 18,755	$ (25,007)	$ 113,981	$ 120,659
Operating income (loss), as reported	$ 5,585	$ (40,526)	$ 111,892	$ 118,150
Plus: operating income from assets acquired from affiliate	11,550	13,810	—	295
Net income (loss)	$ 17,135	$ (26,716)	$ 111,892	$ 118,445
Net income (loss) allocation:				
Limited partners' interest in net income (loss)	$ (247)	$ (45,441)	$ 89,716	$ 115,332
General partner's interest in net income (loss)	$ (36)	$ (735)	$ 1,444	$ 1,843
Net income (loss) per common unit:				
Basic	$ (0.01)	$ (1.45)	$ 2.86	$ 3.68
Diluted	$ (0.01)	$ (1.45)	$ 2.86	$ 3.49

In June 2009, ENP acquired the Williston Basin Assets from Encore Operating. In August 2009, ENP acquired the Rockies and Permian Basin Assets from Encore Operating. Because these assets were acquired from an affiliate, the acquisitions were accounted for as transactions between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of the acquired properties were recorded at Encore Operating's carrying value and ENP's historical financial information was recast to include the acquired properties for all periods in which the properties were owned by Encore Operating. Accordingly, the above selected quarterly financial data reflects the historical results of ENP combined with those of the Williston Basin Assets and the Rockies and Permian Basin Assets.

As discussed in "Note 2. Summary of Significant Accounting Policies" and "Note 8. Earnings Per Unit," ENP adopted ASC 260-10 on January 1, 2009 and all periods have been restated to calculate earnings per unit in accordance therewith.

Exhibit 99.2

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

ENCORE ENERGY PARTNERS LP

CONSOLIDATED BALANCE SHEETS

(in thousands, except unit amounts)

	September 30, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10,283	$ 1,754
Accounts receivable:		
Trade	16,753	24,543
Affiliate	2,628	8,213
Derivatives	15,078	12,881
Other	697	857
Total current assets	45,439	48,248
Properties and equipment, at cost— successful efforts method:		
Proved properties, including wells and related equipment	856,182	851,833
Unproved properties	19	55
Accumulated depletion, depreciation, and amortization	(247,750)	(210,417)
	608,451	641,471
Other property and equipment	991	863
Accumulated depreciation	(575)	(419)
	416	444
Goodwill	9,290	9,290
Other intangibles, net	3,088	3,316
Derivatives	10,023	13,423
Other	2,207	3,459
Total assets	$ 678,914	$ 719,651
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 418	$ 577
Affiliate	2,356	2,780
Accrued liabilities:		
Lease operating	6,363	4,157
Development capital	1,576	1,484
Interest	312	429
Production, ad valorem, and severance taxes	10,988	10,218
Derivatives	5,643	9,815
Oil and natural gas revenues payable	1,611	1,598
Other	1,691	1,632
Total current liabilities	30,958	32,690
Derivatives	9,929	13,401
Future abandonment cost, net of current portion	12,950	12,556
Long-term debt	39	—
Other	240,000	255,000
Total liabilities	293,876	313,647
Commitments and contingencies (see Note4)		
Partners' equity:		
Limited partners— 45,285,347 and 33,077,610 common units issued and outstanding, respectively	386,752	409,777
General partner— 504,851 general partner units issued and outstanding	317	(353
Accumulated other comprehensive loss	(2,031)	(3,420)
Total partners' equity	385,038	406,004
Total liabilities and partners' equity	$ 678,914	$ 719,651

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

ENCORE ENERGY PARTNERS LP

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit amounts)

(unaudited)

	Three months ended September 30,		Nine months ended September 30,	
Revenues:	2010	2009	2010	2009
Oil	$ 36,286	$ 35,494	$ 114,733	$ 88,952
Natural gas	6,497	5,436	21,407	14,624
Marketing	60	102	207	381
Total revenues	42,843	41,032	136,347	103,957
Expenses:				
Production:				
Lease operating	9,607	9,717	31,701	32,614
Production taxes and marketing	4,413	4,523	14,157	11,865
Depletion, depreciation, and amortization	12,782	14,640	38,472	44,226
Exploration	53	3,034	129	3,074
General and administrative	2,817	3,557	10,088	9,800
Derivative fair value loss (gain)	7,609	(4,822)	(14,347)	21,711
Total expenses	37,281	30,649	80,200	123,290
Operating income (loss)	5,562	10,383	56,147	(19,333)
Other income (expenses):				
Interest	(3,277)	(2,984)	(9,912)	(7,551)
Other	9	23	47	34
Total other expenses	(3,268)	(2,961)	(9,865)	(7,517)
Income (loss) before income taxes	2,294	7,422	46,282	(26,850)
Income tax benefit (provision)	147	38	36	(163)
Net income (loss)	$ 2,441	$ 7,460	$ 46,318	(27,013)
Net income (loss) allocation (see Note 8):				
Limited partners' interest in net income (loss)	$ 2,419	$ 5,904	$ 45,813	$ (26,745)
General partner's interest in net income (loss)	$ 22	$ 63	$ 505	$ (444)
Net income (loss) per common unit:				
Basic	$ 0.05	$ 0.13	$ 1.01	$ (0.72)
Diluted	$ 0.05	$ 0.13	$ 1.01	$ (0.72)
Weighted average common units outstanding:				
Basic	45,342	44,653	45,328	37,373
Diluted	45,342	44,675	45,336	37,373
Cash distributions declared per common unit	$ 0.5000	$ 0.5125	$ 1.5375	$ 1.5125

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

ENCORE ENERGY PARTNERS LP

CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY AND

COMPREHENSIVE INCOME

(in thousands, except per unit amounts)

(unaudited)

	Limited Partner		General Partner		Accumulated Other Comprehensive	Total Partners'
	Units	Amount	Units	Amount	Loss	Equity
Balance at December 31, 2009	45,285	$ 409,777	505	$ (353)	$ (3,420)	$ 406,004
Owner contributions	—	(4)	—	935	—	931
Non-cash equity-based compensation	—	1,035	—	8	—	1,043
Vesting of phantom units	57	—	—	—	—	—
Other	—	(186)	—	(2)	—	(188)
Cash distributions to unitholders ($1.5375 per unit)	—	(69,683)	—	(776)	—	(70,459)
Components of comprehensive income:						
Net income attributable to unitholders	—	45,813	—	505	—	46,318
Change in deferred hedge loss on interest rate swaps, net of tax of $6	—	—	—	—	1,389	1,389
Total comprehensive income						47,707
Balance at September 30, 2010	45,342	$ 386,752	505	$ 317	$ (2,031)	$ 385,038

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

ENCORE ENERGY PARTNERS LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

Note 1. Description of Business

ENP is engaged in the acquisition, exploitation, and development of oil and natural gas reserves from onshore fields in the United States. Encore Energy Partners GP LLC (the “General Partner”), a Delaware limited liability company and indirect wholly owned subsidiary of Denbury, serves as ENP’s general partner and Encore Energy Partners Operating LLC (“OLLC”), a Delaware limited liability company and wholly owned subsidiary of ENP, owns and operates ENP’s properties. ENP’s properties and oil and natural gas reserves are located in four core areas:

- the Big Horn Basin in Wyoming and Montana;
- the Permian Basin in West Texas and New Mexico;
- the Williston Basin in North Dakota and Montana; and
- the Arkoma Basin in Arkansas and Oklahoma.

EAC’s Merger with Denbury

On March 9, 2010, Encore Acquisition Company (“EAC”), the former parent of the General Partner, was merged with and into Denbury (the “Merger”), with Denbury surviving the Merger. As part of the Merger, Denbury became the owner of the General Partner and approximately 46 percent of ENP’s outstanding common units. The Merger did not impact the accompanying Consolidated Financial Statements.

Strategic Alternatives and Asset Transaction Processes

On April 30, 2010, ENP and Denbury, the ultimate parent of the General Partner, announced the intent to explore a broad range of strategic alternatives (the “strategic process”) to enhance the value of ENP’s common units, including, but not limited to, those alternatives involving a possible merger, sale, or other transaction involving ENP, Denbury’s interest in the General Partner, or all or part of the ENP common units that Denbury owns. Additionally, ENP and Denbury also announced their intent to explore a sale or other transaction involving one or more of ENP’s assets (the “asset process”), initiated in light of the substantial projected capital requirements required to recognize the full potential value of certain fields owned by ENP which are possible CO_2 tertiary projects, such as the Elk Basin field. On September 2, 2010, ENP and Denbury announced (1) that they had terminated the asset process regarding the Elk Basin field, as no agreement could be reached on the value of the potential tertiary reserves; and (2) Denbury’s ongoing focus upon its intent to sell its interest in the General Partner and all or part of the ENP common units that Denbury owns. Although Denbury intends to sell its interest in the General Partner and all or part of ENP’s common units that Denbury owns, there is no assurance of completion of any transaction.

In May 2010, the Conflicts Committee of the board of directors of the General Partner engaged an investment bank to assist in its responsibilities with regard to the asset process. This agreement was terminated during the third quarter of 2010. In conjunction with entering into this agreement, ENP accrued a $1 million non-refundable retainer fee in the second quarter of 2010, which was paid in the third quarter of 2010, and which is included in “General and administrative expenses” in the accompanying Consolidated Statement of Operations for the nine months ended September 30, 2010. In addition, the Conflicts Committee engaged other advisors such as engineers and legal counsel to help them evaluate any potential transaction and in their capacity as Board members approved paying a fee of $50,000 to each of the members of the Conflicts Committee for considering any potential transaction. These third party expenses and directors’ fees expensed during the three months ended September 30, 2010 totaled approximately $0.5 million, which is included in “General and administrative expenses” in the accompanying Consolidated Statement of Operations.

Note 2. Basis of Presentation

ENP's consolidated financial statements include the accounts of its wholly owned subsidiaries. All material intercompany balances and transactions have been eliminated in consolidation.

In the opinion of management, the accompanying unaudited consolidated financial statements include all adjustments necessary to present fairly, in all material respects, ENP's financial position as of September 30, 2010, results of operations for the three and nine months ended September 30, 2010 and 2009, and cash flows for the nine months ended September 30, 2010 and 2009. All adjustments are of a normal recurring nature. These interim results are not necessarily indicative of results for an entire year.

Certain amounts and disclosures have been condensed or omitted from these consolidated financial statements pursuant to the rules and regulations of the SEC. Therefore, these consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in ENP's 2009 Annual Report on Form 10-K.

Reclassifications

Certain amounts in prior periods have been reclassified to conform to the current period presentation. On the accompanying Consolidated Statements of Operations, NGL revenues were reclassed from "Natural gas revenues" to "Oil revenues," marketing expenses were reclassed to "Production taxes and marketing," ad valorem taxes were reclassed to "Lease operating expenses," and transportation expenses were reclassed to "Production taxes and marketing."

Note 3. Proved Properties

Amounts shown in the accompanying Consolidated Balance Sheets as "Proved properties, including wells and related equipment" consisted of the following as of the dates indicated:

	September 30, 2010	December 31, 2009
Proved leasehold costs	$ 609,910	$ 609,692
Wells and related equipment — Completed	246,162	241,953
Wells and related equipment — In process	110	188
Total proved properties	$ 856,182	$ 851,833

Note 4. Fair Value Measurements

The following table sets forth ENP's book value and estimated fair value of financial instruments as of the dates indicated:

	September 30, 2010		December 31, 2009	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Assets:				
Cash and cash equivalents	$ 10,283	$ 10,283	$ 1,754	$ 1,754
Accounts receivable — trade	16,753	16,753	24,543	24,543
Accounts receivable — affiliate	2,628	2,628	8,213	8,213
Commodity derivative contracts	25,101	25,101	26,304	26,304
Liabilities:				
Accounts payable — trade	418	418	577	577
Accounts payable — affiliate	2,356	2,356	2,780	2,780
Revolving credit facility	240,000	237,636	255,000	252,047
Commodity derivative contracts	13,164	13,164	19,547	19,547
Interest rate swaps	2,408	2,408	3,669	3,669

The book values of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term nature of these instruments. The book value of the revolving credit facility approximates fair value as the interest rate is variable; however, ENP adjusted the estimated fair value for estimated nonperformance risk of approximately $2.4 million and $3.0 million at September 30, 2010 and December 31, 2009, respectively. The nonperformance risk was determined using industry credit default swaps. Commodity derivative contracts and interest rate swaps are marked-to-market each period and are thus stated at fair value in the accompanying Consolidated Balance Sheets.

Derivative Policy

ENP uses various financial instruments for non-trading purposes to manage and reduce price volatility and other market risks associated with its oil and natural gas production. These arrangements are structured to reduce ENP's exposure to commodity price decreases, but they can also limit the benefit ENP might otherwise receive from commodity price increases. ENP's risk management activity is generally accomplished through over-the-counter derivative contracts with large financial institutions, all of which are lenders underwriting ENP's revolving credit facility. ENP also uses derivative instruments in the form of interest rate swaps, which hedge risk related to interest rate fluctuation.

ENP applies the provisions of the "Derivatives" topic of the FASC, which requires each derivative instrument to be recorded in the balance sheet at fair value. If a derivative has not been designated as a hedge or does not otherwise qualify for hedge accounting, it must be adjusted to fair value through earnings. However, if a derivative qualifies for hedge accounting, depending on the nature of the hedge, the effective portion of changes in fair value can be recognized in accumulated other comprehensive income or loss within partners' equity until such time as the hedged item is recognized in earnings. In order to qualify for cash flow hedge accounting, the cash flows from the hedging instrument must be highly effective in offsetting changes in cash flows of the hedged item. In addition, all hedging relationships must be designated, documented, and reassessed periodically.

ENP has elected to designate its outstanding interest rate swaps as cash flow hedges. The effective portion of the mark-to-market gain or loss on these derivative instruments is recorded in "Accumulated other comprehensive loss" on the accompanying Consolidated Balance Sheets and reclassified into earnings in the same period in which the hedged transaction affects earnings. Any ineffective portion of the mark-to-market gain or loss is recognized in earnings and included in "Derivative fair value loss (gain)" in the accompanying Consolidated Statements of Operations.

ENP has elected not to designate its current portfolio of commodity derivative contracts as hedges. Therefore, changes in fair value of these derivative instruments are recognized in earnings and included in "Derivative fair value loss (gain)" in the accompanying Consolidated Statements of Operations.

Commodity Derivative Contracts

ENP manages commodity price risk with swap contracts, put contracts, collars, and floor spreads. Swap contracts provide a fixed price for a notional amount of sales volumes. Put contracts provide a fixed floor price on a notional amount of sales volumes while allowing full price participation if the relevant index price closes above the floor price. Collars provide a floor price for a notional amount of sales volumes while allowing some additional price participation if the relevant index price closes above the floor price.

From time to time, ENP enters into floor spreads. In a floor spread, ENP purchases puts at a specified price (a "purchased put") and also sells a put at a lower price (a "short put"). This strategy enables ENP to achieve some downside protection for a portion of its production, while funding the cost of such protection by selling a put at a lower price. If the price of the commodity falls below the strike price of the purchased put, then ENP has protection against commodity price decreases for the covered production down to the strike price of the short put. At commodity prices below the strike price of the short put, the benefit from the purchased put is generally offset by the expense associated with the short put. For example, in 2007, ENP purchased oil put options for 2,000 Bbls/D in 2010 at $65 per Bbl. As NYMEX prices increased in 2008, ENP wished to protect downside price exposure at the higher price. In order to do this, ENP purchased oil put options for 2,000 Bbls/D in 2010 at $75 per Bbl and simultaneously sold oil put options for 2,000 Bbls/D in 2010 at $65 per Bbl. Thus, after these transactions were completed, ENP had purchased two oil put options for 2,000 Bbls/D in 2010 (one at $65 per Bbl and one at $75 per Bbl) and sold one oil put option for 2,000 Bbls/D in 2010 at $65 per Bbl. However, the net result was ENP effectively owning one oil put option for 2,000 Bbls/D in 2010 at $75 per Bbl. The following tables include information on both ENP's purchased floor component of its floor spreads net and ENP's other floor contracts.

The following tables summarize ENP's open commodity derivative contracts as of September 30, 2010:

Oil Derivative Contracts

	Average Daily Floor Volume	Weighted Average Floor Price	Average Daily Cap Volume	Weighted Average Cap Price	Average Daily Swap Volume	Weighted Average Swap Price	Asset (Liability) Fair Market Value
	(Bbls)	(per Bbl)	(Bbls)	(per Bbl)	(Bbls)	(per Bbl)	(in thousands)
Oct. — Dec. 2010							(853)
	880	80.00	440	93.80	760	75.43	
	2,000	75.00	1,000	77.23	250	65.95	
	760	67.00	—	—	—	—	
2011							1,084
	1,880	80.00	1,440	95.41	760	78.46	
	1,000	70.00	—	—	—	—	
	760	65.00	—	—	250	69.65	
2012							(5,566)
	750	70.00	500	82.05	210	81.62	
	1,510	65.00	250	79.25	1,300	76.54	
							(5,335)

Natural Gas Derivative Contracts

	Average Daily Floor Volume	Weighted Average Floor Price	Average Daily Cap Volume	Weighted Average Cap Price	Average Daily Swap Volume	Weighted Average Swap Price	Asset Fair Market Value
	(Mcf)	(per Mcf)	(Mcf)	(per Mcf)	(Mcf)	(per Mcf)	(in thousands)
Oct. — Dec. 2010							$ 4,301
	3,800	$ 8.20	3,800	$ 9.58	5,452	$ 6.20	
	4,698	7.26	—	—	550	5.86	
2011							9,083
	3,398	6.31	—	—	7,952	6.36	
	—	—	—	—	550	5.86	
2012							3,888
	898	6.76	—	—	5,452	6.26	
	—	—	—	—	550	5.86	
							$ 17,272

Counterparty Risk. At September 30, 2010, ENP had committed 10 percent or greater (in terms of fair market value) of either its oil or natural gas derivative contracts in asset positions to the following counterparties:

Counterparty	Fair Market Value of Oil Derivative Contracts Committed	Fair Market Value of Natural Gas Derivative Contracts Committed
	(in thousands)	
BNP Paribas	$ 3,610	$ 4,084
Calyon	2,082	8,462
RBC	2,157	4,372

In order to mitigate the credit risk of financial instruments, ENP enters into master netting agreements with certain counterparties. The master netting agreement is a standardized, bilateral contract between a given counterparty and ENP. Instead of treating each financial transaction between the counterparty and ENP separately, the master netting agreement enables the counterparty and ENP to aggregate all financial trades and treat them as a single agreement. This arrangement is intended to benefit ENP in three ways: (1) the netting of the value of all trades reduces the likelihood of counterparties requiring daily collateral posting by ENP; (2) default by a counterparty under one financial trade can trigger rights to terminate all financial trades with such counterparty; and (3) netting of settlement amounts reduces ENP's credit exposure to a given counterparty in the event of close-out. ENP's accounting policy is to not offset fair value amounts for derivative instruments.

Interest Rate Swaps

ENP uses derivative instruments in the form of interest rate swaps, which hedge risk related to interest rate fluctuation, whereby it converts the interest due on certain floating rate debt under its revolving credit facility to a weighted average fixed rate. The following table summarizes ENP's open interest rate swaps as of September 30, 2010, all of which were entered into with Bank of America, N.A.:

	Notional Amount	**Fixed Rate**	**Floating Rate**
		(in thousands)	
Oct. 2010 - Jan. 2011	50,000	3.1610%	1-month LIBOR
Oct. 2010 - Jan. 2011	25,000	2.9650%	1-month LIBOR
Oct. 2010 - Jan. 2011	25,000	2.9613%	1-month LIBOR
Oct. 2010 - Mar. 2012	50,000	2.4200%	1-month LIBOR

Current Period Impact

ENP recognizes derivative fair value gains and losses related to: (1) ineffectiveness on derivative contracts designated as hedges; (2) changes in the fair market value of derivative contracts not designated as hedges; (3) receipts and settlements on derivative contracts not designated as hedges; and (4) premium amortization. The following table summarizes the components of "Derivative fair value loss (gain)" for the periods indicated:

	Three months ended September 30,		**Nine months ended September 30,**	
	2010	**2009**	**2010**	**2009**
		(in thousands)		
Ineffectiveness on interest rate swaps	29	18	133	(16)
Mark-to-market loss (gain)	8,922	4,957	(12,521)	62,638
Premium amortization	2,474	5,918	7,342	17,326
Receipts, net of settlements	(3,816)	(15,715)	(9,301)	(58,237)
Total derivative fair value loss (gain)	7,609	(4,822	(14,347)	21,711

Accumulated Other Comprehensive Loss

At September 30, 2010 and December 31, 2009, "Accumulated other comprehensive loss" on the accompanying Consolidated Balance Sheets consisted entirely of deferred losses, net of tax, on ENP's interest rate swaps of $2.0 million and $3.4 million, respectively. During the twelve months ending September 30, 2011, ENP expects to reclassify $1.9 million of deferred losses associated with its interest rate swaps from accumulated other comprehensive loss to interest expense. The actual gains or losses ENP will realize from its interest rate swaps may vary significantly from the deferred losses recorded in "Accumulated other comprehensive loss" in the accompanying Consolidated Balance Sheet due to fluctuations in interest rates.

Tabular Disclosures of Fair Value Measurements

The following table summarizes the fair value of ENP's derivative contracts as of the dates indicated (in thousands):

	Asset Derivatives			Liability Derivatives		
		Fair Value			Fair Value	
	Balance Sheet Location	September 30, 2010	December 31, 2009	Balance Sheet Location	September 30, 2010	December 31, 2009
Derivatives not designated as hedges						
Commodity derivative contracts	Derivatives - current	$ 15,078	$ 12,881	Derivatives - current	$ 3,719	$ 6,393
Commodity derivative contracts	Derivatives - noncurrent	10,023	13,423	Derivatives - noncurrent	9,445	13,154
Total derivatives not designated as hedges		$ 25,101	$ 26,304		$ 13,164	$ 19,547
Derivatives designated as hedges						
Interest rate swaps	Derivatives - current	$ —	$ —	Derivatives - current	$ 1,924	$ 3,422
Interest rate swaps	Derivatives - noncurrent	—	—	Derivatives - noncurrent	484	247
Total derivatives designated as hedges		$ —	$ —		$ 2,408	$ 3,669
Total derivatives		$ 25,101	$ 26,304		$ 15,572	$ 23,216

The following table summarizes the effect of derivative instruments not designated as hedges on the Consolidated Statements of Operations for the periods indicated (in thousands):

		Amount of Loss (Gain) Recognized in Income Three Months Ended September 30,		Amount of Loss (Gain) Recognized in Income Nine Months Ended September 30,	
Derivatives Not Designated as Hedges	**Location of Loss (Gain) Recognized in Income**	**2010**	**2009**	**2010**	**2009**
Commodity derivative contracts	Derivative fair value loss (gain)	$ 7,580	$ (4,840)	$ (14,480)	21,727

The following tables summarize the effect of derivative instruments designated as hedges on the Consolidated Statements of Operations for the periods indicated (in thousands):

	Amount of Loss Recognized in Accumulated OCI (Effective Portion) Three Months Ended September 30,		Amount of Loss Recognized in Accumulated OCI (Effective Portion) Nine Months Ended September 30,	
Derivatives Designated as Hedges	**2010**	**2009**	**2010**	**2009**
Income expense	$ 401	$ 1,289	$ 1,536	$ 2,444

	Amount of Loss Reclassified from Accumulated OCI into Income (Effective Portion) Three Months Ended September 30,		Amount of Loss Reclassified from Accumulated OCI into Income (Effective Portion) Nine Months Ended September 30,	
Location of Loss Reclassified from Accumulated OCI into Income (Effective Portion)	**2010**	**2009**	**2010**	**2009**
Income expense	$ 974	$ 983	$ 2,925	$ 2,786

Location of Loss Recognized in Income as Ineffective	Amount of Loss Recognized in Income as Ineffective Three Months Ended September 30, 2010	 2009	Amount of Loss (Gain) Recognized in Income as Ineffective Nine Months Ended September 30, 2010	 2009
Derivative fair value loss (gain)	$ 29	$ 18	$ 133	$ (16)

Fair Value Hierarchy

The FASC established a fair value hierarchy that prioritizes the inputs used to measure fair value. The three levels of the fair value hierarchy are as follows:

- Level 1 — Unadjusted quoted prices are available in active markets for identical assets or liabilities.

- Level 2 — Pricing inputs, other than quoted prices within Level 1, that are either directly or indirectly observable.

- Level 3 — Pricing inputs that are unobservable requiring the use of valuation methodologies that result in management's best estimate of fair value.

ENP's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the financial assets and liabilities and their placement within the fair value hierarchy levels. The following methods and assumptions were used to estimate the fair values of ENP's assets and liabilities that are accounted for at fair value on a recurring basis:

- Level 2 — Fair values of oil and natural gas swaps were estimated using a combined income-based and market-based valuation methodology based upon forward commodity price curves obtained from independent pricing services reflecting broker market quotes. Fair values of interest rate swaps were estimated using a combined income-based and market-based valuation methodology based upon credit ratings and forward interest rate yield curves obtained from independent pricing services reflecting broker market quotes.

- Level 3 — ENP's oil and natural gas calls, puts, and short puts are average value options, which are not exchange—traded contracts. Settlement is determined by the average underlying price over a predetermined period of time. ENP uses both observable and unobservable inputs in a Black-Scholes valuation model to determine fair value. Accordingly, these derivative instruments are classified within the Level 3 valuation hierarchy. The observable inputs of ENP's valuation model include: (1) current market and contractual prices for the underlying instruments; (2) quoted forward prices for oil and natural gas; and (3) interest rates, such as a LIBOR curve for a term similar to the commodity derivative contract. The unobservable inputs of ENP's valuation model include volatility. The implied volatilities for ENP's calls, puts, and short puts with comparable strike prices are based on the settlement values from certain exchange-traded contracts. The implied volatilities for calls, puts, and short puts where there are no exchange-traded contracts with the same strike price are extrapolated from exchange-traded implied volatilities by an independent party.

ENP adjusts the valuations from the valuation model for nonperformance risk, using management's estimate of the counterparty's credit quality for asset positions and ENP's credit quality for liability positions. ENP uses multiple sources of third-party credit data in determining counterparty nonperformance risk, including credit default swaps.

The following table sets forth ENP's assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2010:

Description	Asset (Liability)	Fair Value Measurements at Reporting Date Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(in thousands)			
Oil derivative contracts — swaps	$ (9,254)	$ —	$ (9,254)	$ —
Oil derivative contracts — floors and caps	3,919	—	—	3,919
Natural gas derivative contracts — swaps	11,056	—	11,056	
Natural gas derivative contracts — floors and caps	6,216	—	—	6,216
Interest rate swaps	(2,408)	—	(2,408)	—
Total	$ 9,529	$ —	$ (606)	$ 10,135

The following table summarizes the changes in the fair value of ENP's Level 3 assets and liabilities for the nine months ended September 30, 2010:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3): Oil Derivative Natural Gas Contracts – Floors and Caps	Natural Gas Derivative Contracts - Floors and Caps	Total
	(in thousands)		
Balance at January 1, 2010	$ 8,585	$ 8,528	$ 17,113
Total gains (losses):			
Included in earnings	(4,996)	(9,566)	(14,562)
Settlements	330	7,254	7,584
Balance at September 30, 2010	$ 3,919	$ 6,216	$ 10,135
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets still held at the reporting date	$ (4,996)	$ (9,566)	$ (14,562)

Since ENP does not use hedge accounting for its commodity derivative contracts, all gains and losses on its Level 3 assets and liabilities are included in "Derivative fair value loss (gain)" in the accompanying Consolidated Statements of Operations.

All fair values have been adjusted for nonperformance risk resulting in a decrease of the net commodity derivative asset of approximately $0.1 million as of September 30, 2010. For commodity derivative contracts which are in an asset position, ENP uses the counterparty's credit default swap rating. For commodity derivative contracts which are in a liability position, ENP uses the average credit default swap rating of its peer companies as ENP does not have its own credit default swap rating.

Note 5. Asset Retirement Obligations

Asset retirement obligations relate to future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal. The following table summarizes the changes in ENP's asset retirement obligations for the nine months ended September 30, 2010 (in thousands):

Future abandonment liability at January 1, 2010	$ 13,130
Accretion of discount	548
Revision of previous estimates	66
Plugging and abandonment costs incurred	(96)
Future abandonment liability at September 30, 2010	$ 13,648

As of September 30, 2010, $12.9 million of ENP's asset retirement obligations were long-term and recorded in "Future abandonment cost, net of current portion" and $0.7 million were current and included in "Other current liabilities" in the accompanying Consolidated Balance Sheet. Approximately $5.0 million of the long-term future abandonment liability represents the estimated cost for decommissioning the Elk Basin natural gas processing plant.

Note 6. Long-Term Debt

OLLC is a party to a five-year credit agreement dated March 7, 2007 (as amended, the "OLLC Credit Agreement"). The OLLC Credit Agreement matures on March 7, 2012. In November 2009, OLLC amended the OLLC Credit Agreement, which amendment was effective upon the closing of the Merger, to, among other things, permit the consummation of the Merger not being treated as a "Change of Control" under the OLLC Credit Agreement. Denbury paid a fee of approximately $0.9 million for this bank waiver and did not seek reimbursement from ENP for this payment. As such, the $0.9 million paid by Denbury is reflected as a capital contribution to ENP by Denbury in its capacity as the parent of the General Partner and is included in "General and administrative expense" in the accompanying Consolidated Statement of Operations for the nine months ended September 30, 2010 as a non-cash expense.

The OLLC Credit Agreement provides for revolving credit loans to be made to OLLC from time to time and letters of credit to be issued from time to time for the account of OLLC or any of its restricted subsidiaries. The aggregate amount of the commitments of the lenders under the OLLC Credit Agreement is $475 million. Availability under the OLLC Credit Agreement is subject to a borrowing base, which is redetermined semi-annually and upon requested special redeterminations. On June 14, 2010, the borrowing base under the OLLC Credit Agreement was reaffirmed at $375 million. As of September 30, 2010, there were $240 million of outstanding borrowings and $135 million of borrowing capacity under the OLLC Credit Agreement.

OLLC incurs a quarterly commitment fee at a rate of 0.5 percent per year on the unused portion of the OLLC Credit Agreement.

Obligations under the OLLC Credit Agreement are secured by a first-priority security interest in substantially all of OLLC's proved oil and natural gas reserves and in the equity interests of OLLC and its restricted subsidiaries. In addition, obligations under the OLLC Credit Agreement are guaranteed by ENP and OLLC's restricted subsidiaries. Obligations under the OLLC Credit Agreement are non-recourse to Denbury and its restricted subsidiaries.

Loans under the OLLC Credit Agreement are subject to varying rates of interest based on (1) amount outstanding in relation to the borrowing base and (2) whether the loan is a Eurodollar loan or a base rate loan. Eurodollar loans under the OLLC Credit Agreement bear interest at the Eurodollar rate plus the applicable margin indicated in the following table, and base rate loans under the OLLC Credit Agreement bear interest at the base rate plus the applicable margin indicated in the following table:

Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans
Less than .50 to 1	2.250%	1.250%
Greater than or equal to .50 to 1 but less than .75 to 1	2.500%	1.500%
Greater than or equal to .75 to 1 but less than .90 to 1	2.750%	1.750%
Greater than or equal to .90 to 1	3.000%	2.000%

The "Eurodollar rate" for any interest period (either one, two, three, or six months, as selected by ENP) is the rate equal to the British Bankers Association LIBOR for deposits in dollars for a similar interest period. The "Base Rate" is calculated as the highest of: (1) the annual rate of interest announced by Bank of America, N.A. as its "prime rate"; (2) the federal funds effective rate plus 0.5 percent; or (3) except during a "LIBOR Unavailability Period," the Eurodollar rate (for dollar deposits for a one-month term) for such day plus 1.0 percent.

Any outstanding letters of credit reduce the availability under the OLLC Credit Agreement. Borrowings under the OLLC Credit Agreement may be repaid from time to time without penalty.

The OLLC Credit Agreement contains several restrictive covenants including, among others, the following:

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against purchasing or redeeming capital stock, or prepaying indebtedness, subject to permitted exceptions;
- a restriction on creating liens on the assets of ENP, OLLC, and OLLC's restricted subsidiaries, subject to permitted exceptions;
- restrictions on merging and selling assets outside the ordinary course of business;
- restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business;
- a provision limiting oil and natural gas hedging transactions (other than puts) to a volume not exceeding 75 percent of anticipated production from proved producing reserves;
- a requirement that ENP and OLLC maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0;
- a requirement that ENP and OLLC maintain a ratio of consolidated EBITDA, as defined in the OLLC Credit Agreement, to the sum of consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0; and
- a requirement that ENP and OLLC maintain a ratio of consolidated funded debt to consolidated adjusted EBITDA of not more than 3.5 to 1.0.

As of September 30, 2010, ENP and OLLC were in compliance with all covenants of the OLLC Credit Agreement.

The OLLC Credit Agreement contains customary events of default including, among others, the following:

- failure to pay principal on any loan when due;
- failure to pay accrued interest on any loan or fees when due and such failure continues for more than three days;
- failure to observe or perform covenants and agreements contained in the OLLC Credit Agreement, subject in some cases to a 30-day grace period after discovery or notice of such failure;
- failure to make a payment when due on any other debt in a principal amount equal to or greater than $3 million or any other event or condition occurs which results in the acceleration of such debt or entitles the holder of such debt to accelerate the maturity of such debt;
- the commencement of liquidation, reorganization, or similar proceedings with respect to OLLC or any guarantor under bankruptcy or insolvency law, or the failure of OLLC or any guarantor generally to pay its debts as they become due;
- the entry of one or more judgments in excess of $3 million (to the extent not covered by insurance) and such judgment(s) remain unsatisfied and unstayed for 30 days;
- the occurrence of certain ERISA events involving an amount in excess of $3 million;
- there cease to exist liens covering at least 80 percent of the borrowing base properties; or
- the occurrence of a change in control, as defined in the OLLC Credit Agreement.

If an event of default occurs and is continuing, lenders with a majority of the aggregate commitments may require Bank of America, N.A. to declare all amounts outstanding under the OLLC Credit Agreement to be immediately due and payable.

Note 7. Partners' Equity and Distributions

Distributions

ENP's partnership agreement requires that, within 45 days after the end of each quarter, it distribute all of its available cash (as defined in ENP's partnership agreement) to its unitholders. ENP's available cash is its cash on hand at the end of a quarter after the payment of its expenses and the establishment of reserves for future capital expenditures and operational needs. Distributions are not cumulative. ENP distributes available cash to its unitholders in accordance with their ownership percentages.

The following table illustrates information regarding ENP's distributions of available cash for the periods indicated:

	Date Declared	Cash Distribution Declared per Common Unit	Date Paid	Total Distribution
				(in thousands)
2010				
Quarter ended September 30	10/28/2010	$ 0.5000	11/12/2010(a)	$ 22,923 (a)
Quarter ended June 30	7/29/2010	$ 0.5000	8/13/2010	22,923
Quarter ended March 31	4/30/2010	$ 0.5000	5/14/2010	22,923
2009				
Quarter ended December 31	1/25/2010	$ 0.5375	2/12/2010	24,642
Quarter ended September 30	10/26/2009	$ 0.5375	11/13/2009	24,642
Quarter ended June 30	7/27/2009	$ 0.5125	8/14/2009	23,481
Quarter ended March 31	4/27/2009	$ 0.5000	5/15/2009	16,813
2008				
Quarter ended December 31	1/26/2009	$ 0.5000	2/13/2009	16,813

(a) Represents the date the distribution is expected to be paid and the total amount of the distribution that is expected to be paid.

Note 8. Earnings Per Unit

ENP applies the provisions of the "Earnings Per Share" topic of the FASC, which requires earnings per unit to be calculated using the two-class method. Under the two-class method of calculating earnings per unit, earnings are allocated to participating securities as if all earnings for the period had been distributed. A participating security is any security that may participate in distributions with common units. For purposes of calculating earnings per unit, general partner units and unvested phantom units are considered participating securities. Earnings per unit is calculated by dividing the limited partners' interest in net income (loss), after deducting the interests of participating securities, by the weighted average common units outstanding.

The following table reflects the allocation of net income (loss) to ENP's limited partners and earnings per unit computations for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands, except per unit amount)			
Net income (loss)	$ 2,441	$ 7,460	$ 46,318	$ (27,013)
Less: net income for pre-partnership operations of assets acquired from affiliates	—	(1,493)	—	(176)
Net income (loss) attributable to unitholders	$ 2,441	$ 5,967	$ 46,318	$ (27,189)
Numerator:				
Numerator for basic earnings per unit:				
Net income (loss) attributable to unitholders	$ 2,441	$ 5,967	$ 46,318	$ (27,189)
Less: distributions earned by participating securities	(253)	(271)	(757)	(783)
Plus: cash distributions in excess of (less than) income allocated to the general partner	231	208	252	1,227
Net income (loss) allocated to limited partners	$ 2,419	$ 5,904	$ 45,813	$ (26,745)
Denominator:				
Denominator for basic earnings per unit:				
Weighted average common units outstanding	45,342	44,653	45,328	37,373
Effect of dilutive phantom units (a)	—	22	8	—
Denominator for diluted earnings per unit	45,342	44,675	45,336	37,373
Net income (loss) per common unit:				
Basic	$ 0.05	$ 0.13	$ 1.01	$ (0.72)
Diluted	$ 0.05	$ 0.13	$ 1.01	$ (0.72)

(a) For the nine months ended months ended September 30, 2009, 43,750 phantom units were outstanding but were excluded from the diluted EPU calculations because their effect would have been antidilutive. Please read "Note 9. Unit-Based Compensation Plans" for additional discussion of phantom units.

Note 9. Unit-Based Compensation Plans

Long-Term Incentive Plan

In September 2007, the board of directors of the General Partner adopted the Encore Energy Partners GP LLC Long-Term Incentive Plan (the "LTIP"), which provides for the granting of options, restricted units, phantom units, unit appreciation rights, distribution equivalent rights, other unit-based awards, and unit awards. All employees, consultants, and directors of the General Partner and its affiliates who perform services for or on behalf of ENP and its subsidiaries are eligible to be granted awards under the LTIP. The LTIP is administered by the board of directors of the General Partner or a committee thereof, referred to as the plan administrator. To satisfy common unit awards under the LTIP, ENP may acquire common units in the open market, use common units owned by the General Partner, or use common units acquired by the General Partner from ENP or from any other person.

The total number of common units reserved for issuance pursuant to the LTIP is 1,150,000. As of September 30, 2010, there were 1,075,000 common units available for issuance under the LTIP with none outstanding.

Phantom Units. As a result of the change of control of the General Partner in conjunction with the Merger of EAC with and into Denbury, all 56,250 of ENP's outstanding phantom units vested and were settled in an equal number of ENP's common units. The acceleration of the phantom unit vesting resulted in the recognition of the remaining unrecognized unit-based compensation expense during March 2010. The fair value of these phantom units was approximately $1.2 million on the date of the Merger. During the nine months ended September 30, 2010 and 2009, ENP recognized non-cash unit-based compensation expense related to phantom units of approximately $0.7 million (upon closing of the Merger on March 9, 2010) and $0.3 million, respectively, which is included in "General and administrative expense" in the accompanying Consolidated Statements of Operations. As of September 30, 2010, there were no outstanding phantom units.

Note 10. Comprehensive Income (Loss)

The components of comprehensive income (loss), net of tax, were as follows for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Net income (loss)	$ 2,441	$ 7,460	$ 46,318	$ (27,013)
Change in deferred hedge loss on interest rate swaps	573	(306)	1,389	342
Comprehensive income (loss)	$ 3,014	$ 7,154	$ 47,707	$ (26,671)

Note 11. Commitments and Contingencies

ENP is a party to ongoing legal proceedings in the ordinary course of business. The General Partner's management does not believe the result of these proceedings will have a material adverse effect on ENP's business, financial condition, results of operations, liquidity, or ability to pay distributions.

Additionally, ENP has contractual obligations related to future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal, long-term debt, derivative contracts, operating leases, and development commitments. Please read "Capital Commitments, Capital Resources, and Liquidity — Capital commitments — Contractual obligations" included in "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations" of this Report for ENP's contractual obligations as of September 30, 2010.

Note 12. Related Party Transactions

Administrative Services Agreement

ENP does not have any employees. The employees supporting the operations of ENP are employees of Denbury. Encore Operating, L.P. ("Encore Operating"), a Texas limited partnership and indirect wholly-owned subsidiary of Denbury, performs administrative services for ENP, such as accounting, corporate development, finance, land, legal, and engineering, pursuant to an administrative services agreement. In addition, Encore Operating provides all personnel, facilities, goods, and equipment necessary to perform these services which are not otherwise provided for by ENP. Encore Operating is not liable to ENP for its performance of, or failure to perform, services under the administrative services agreement unless its acts or omissions constitute gross negligence or willful misconduct.

From April 1, 2008 to March 31, 2009, the administrative fee charged by Encore Operating to ENP under the administrative services agreement was $1.88 per BOE of ENP's production. From April 1, 2009 to March 31, 2010, the administrative fee was $2.02 per BOE of ENP's production. Effective April 1, 2010, the administrative fee increased to $2.06 per BOE of ENP's production. ENP also reimburses Encore Operating for actual third-party expenses incurred on ENP's behalf under the administrative services agreement. In addition, Encore Operating is entitled to retain any COPAS overhead charges associated with drilling and operating wells that would otherwise be paid by non-operating interest owners to the operator.

The administrative fee will increase in the following circumstances:

- beginning on the first day of April in each year by an amount equal to the product of the then-current administrative fee multiplied by the COPAS Wage Index Adjustment for that year;
- if ENP acquires additional assets, Encore Operating may propose an increase in its administrative fee that covers the provision of services for such additional assets; however, such proposal must be approved by the board of directors of the General Partner upon the recommendation of its Conflicts Committee; and
- otherwise as agreed upon by Encore Operating and the General Partner, with the approval of the Conflicts Committee of the board of directors of the General Partner.

ENP reimburses Denbury for any state, income, franchise, or similar tax incurred by Denbury resulting from the inclusion of ENP in consolidated tax returns of Denbury as required by applicable law. The amount of any such reimbursement is limited to the tax that ENP would have incurred had it not been included in a combined group with Denbury.

Administrative fees (including COPAS recovery) paid to Encore Operating pursuant to the administrative services agreement are included in “General and administrative expenses” in the accompanying Consolidated Statement of Operations. The reimbursements of actual third-party expenses incurred by Encore Operating on ENP’s behalf are included in “Lease operating expense” or “General and administrative expenses” in the accompanying Consolidated Statement of Operations based on the nature of the expense. The following table illustrates amounts paid by ENP to Encore Operating pursuant to the administrative service agreement for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Administrative fees (including COPAS recovery)	$ 2,276	$ 1,325	$ 7,717	$ 4,150
Third-party expenses	1,212	1,059	4,527	4,031

As of September 30, 2010, ENP had a payable to Denbury of $2.4 million which is reflected as “Accounts payable — affiliate” in the accompanying Consolidated Balance Sheets, and a receivable from Denbury of $2.6 million which is reflected as “Accounts receivable — affiliate” in the accompanying Consolidated Balance Sheets. As of December 31, 2009, ENP had a payable to EAC of $2.8 million which is reflected as “Accounts payable — affiliate” in the accompanying Consolidated Balance Sheets, and a receivable from EAC of $8.2 million which is reflected as “Accounts receivable — affiliate” in the accompanying Consolidated Balance Sheets.

Acquisitions

In January 2009, ENP acquired certain oil and natural gas properties and related assets in the Arkoma Basin in Arkansas and royalty interest properties primarily in Oklahoma, as well as 10,300 unleased mineral acres (the “Arkoma Basin Assets”) from Encore Operating, at the time a subsidiary of EAC, for approximately $46.4 million. In June 2009, ENP acquired certain oil and natural gas properties and related assets in the Williston Basin in North Dakota and Montana (the “Williston Basin Assets”) from Encore Operating for approximately $25.2 million. In August 2009, ENP acquired certain oil and natural gas properties and related assets in the Big Horn Basin in Wyoming, the Permian Basin in West Texas and New Mexico, and the Williston Basin in Montana and North Dakota (the “Rockies and Permian Basin Assets”) from Encore Operating for approximately $179.6 million in cash. Prior to the acquisition by ENP, the properties were owned by EAC and were not separate legal entities.

In addition to payroll-related expenses, EAC incurred general and administrative expenses related to leasing office space and other corporate overhead expenses during the period these properties were owned by EAC. A portion of EAC’s consolidated general and administrative expenses was allocated to ENP and included in the accompanying Consolidated Statements of Operations based on the respective percentage of BOE produced by the properties in relation to the total BOE produced by EAC on a consolidated basis for the three and nine months ended September 30, 2009. A portion of EAC’s consolidated indirect lease operating overhead expenses was allocated to ENP included in the accompanying Consolidated Statements of Operations based on its share of EAC’s direct lease operating expense for the three and nine months ended September 30, 2009.

Distributions

Each quarter, ENP pays cash distributions with respect to operations in the previous quarter on all of its outstanding units, including those common units held by the General Partner and its affiliates, and pays cash distributions to the General Partner based upon its general partner interest. On each of August 13, 2010 and May 14, 2010, ENP paid cash distributions of approximately $22.9 million, of which $10.7 million was paid to the General Partner and its affiliates. On February 12, 2010, ENP paid cash distributions of approximately $24.6 million, of which $11.5 million was paid to the General Partner and its affiliates. On August 14, 2009, ENP paid cash distributions of approximately $23.5 million, of which $11.0 million was paid to the General Partner and its affiliates. On each of May 15, 2009 and February 13, 2009, ENP paid cash distributions of approximately $16.8 million, of which $10.7 million was paid to the General Partner and its affiliates.

Note 13. Subsequent Events

On October 28, 2010, the board of directors of the General Partner declared an ENP cash distribution for the third quarter of 2010 to unitholders of record as of the close of business on November 8, 2010 of $0.50 per unit or approximately $22.9 million of which $10.7 million is expected to be paid to the General Partner and its affiliates. The distribution is expected to be paid to unitholders on or about November 12, 2010.

Exhibit 99.3

Vanguard Natural Resources, LLC
Unaudited pro forma combined financial information

The following unaudited pro forma combined financial information is based on the historical consolidated financial statements of Vanguard Natural Resources, LLC and subsidiaries ("Vanguard") and Encore Energy Partners LP, a Delaware limited partnership ("Encore"), adjusted to reflect (1) the proposed acquisition by Vanguard of all of the member interests of Encore Energy Partners GP LLC, a Delaware limited liability company (which holds 504,851 general partner units in Encore that represent a one point one percent (1.10%) interest in Encore), and 20,924,055 common units of Encore (which represent an approximate forty-six percent (46%) limited partner interest in Encore) (collectively the "Encore Interests"), from Denbury Resources Inc. ("Denbury"), for $380.0 million (the "Acquisition"), (2) the Vanguard common unit offering completed in October 2010, (3) the anticipated issuance of Vanguard's common units to Denbury, and (4) other financing transactions described below. Vanguard's historical consolidated statements of operations have also been adjusted to give pro forma effect to the Sun TSH, Ward County and Parker Creek acquisitions of natural gas and oil properties completed during 2009 and 2010 as presented in Note 4 to the unaudited pro forma combined financial information.

The unaudited pro forma combined financial statements give effect to the events set forth below:

- Vanguard's acquisition of the Encore Interests. The acquisition of the Encore Interests will be accounted for using the acquisition method of accounting. The unaudited pro forma combined financial information reflects the preliminary allocation of (1) the consideration to be paid and (2) the market value of the noncontrolling interest of Encore to the underlying assets acquired and liabilities assumed of Encore based upon their estimated fair values.

- Borrowings under a new $175.0 million term loan. Borrowings under the newly committed term loan will be used to fund a portion of the $380.0 million purchase price for the Encore Interests. The term loan matures in one year from the date of funding and its lenders will have a first lien on the Encore Interests and a second lien on Vanguard's natural gas and oil properties.

- The approximate 4.8 million Vanguard common unit offering completed in October 2010. The units were offered to the public at a price of $25.40 per unit. Vanguard received proceeds of approximately $112.5 million from the offering, after deducting underwriting discounts of $5.1 million and paying $3.7 million of the proceeds to redeem 150,000 common units from Vanguard's largest unitholder, but before deducting $0.02 million in expenses. The proceeds will be used to fund a portion of the $380.0 million purchase price for the Encore Interests.

- The issuance of approximately 3.1 million Vanguard common units to Denbury as partial consideration for the purchase of the Encore Interests. Pursuant to the Purchase Agreement, Vanguard may elect to pay up to $80.0 million of the $380.0 million purchase price in Vanguard common units. The price of the Vanguard common units to be issued to Denbury was established at $25.50 per common unit pursuant to the Purchase Agreement. The unaudited pro forma combined financial information assumes that Vanguard has elected to exercise its option in full and anticipates issuing approximately 3.1 million Vanguard common units.

- Borrowings of approximately $18.8 million under Vanguard's existing reserve-based credit facility. Proceeds from the borrowings will be used to fund the remaining portion of the purchase price, pay debt issuance costs (approximately $2.8 million) and transaction expenses (approximately $3.6 million) related to the Acquisition.

- Adjustments to conform the classification of revenues and expenses in Encore's historical statements of operations to Vanguard's classification of similar revenues and expenses.

- Adjustments to conform Encore's historical accounting policies related to natural gas and oil properties from successful efforts to full cost accounting.

- Vanguard's Sun TSH, Ward County and Parker Creek acquisitions of natural gas and oil properties completed during 2009 and 2010 and the effect of the related equity offerings.

The unaudited pro forma combined balance sheet gives effect to the acquisition of the Encore Interests by Vanguard, the Vanguard common unit offering completed in October 2010, and the anticipated issuance of Vanguard's common units to Denbury and financing transactions described below, as if they had occurred on September 30, 2010. The unaudited pro forma combined statements of operations combine the results of operations of Vanguard and Encore for the year ended December 31, 2009 and the nine months ended September 30, 2010, as if the acquisition of the Encore Interests, the Sun TSH, Ward County and Parker Creek acquisitions of natural gas and oil properties completed during 2009 and 2010 (see Note 4) and the financing transactions had occurred on January 1, 2009.

The unaudited pro forma combined statements of operations exclude the following:

- The impact of nonrecurring expenses Vanguard and Encore will incur as a result of the Acquisition and related issuance of Vanguard's common units to Denbury and financing transactions, primarily non-capitalizable legal and advisory fees;

- nonrecurring gains and a nonrecurring loss related to the Vanguard's Sun TSH, Ward County and Parker Creek acquisitions; and

- the fee and expense reimbursement associated with the administrative services agreement which will transfer to Vanguard upon the closing of the Acquisition due to the uncertainty of determining the amount of expenses Vanguard would have incurred. Encore entered into this administrative services agreement with Encore Operating L.P., a Texas limited partnership and indirect wholly-owned subsidiary of Denbury pursuant to which Encore Operating L.P. performs administrative services for Encore, such as accounting, corporate development, finance, land, legal, and engineering. In addition, Encore Operating L. P. provides all personnel, facilities, goods, and equipment necessary to perform these services which are not otherwise provided for by Encore. The administration fee is $2.06 per BOE of Encore's production. Encore also reimburses Encore Operating L. P. for actual third-party expenses incurred on Encore's behalf. Encore Operating L. P. has substantial discretion in determining which third-party expenses to incur on Encore's behalf. In addition, Encore Operating L. P. is entitled to retain any COPAS overhead charges associated with drilling and operating wells that would otherwise be paid by non-operating interest owners to the operator.

The unaudited pro forma combined financial information should be read in conjunction with the Form 10-K of Vanguard for the year ended December 31, 2009 and the Form 10-Q of Vanguard for the quarter ended September 30, 2010 and the historical financial statements of Encore for the year ended December 31, 2009 and for the nine months ended September 30, 2010. Encore's historical consolidated financial statements and the notes thereto for each of the three years ended December 31, 2009, 2008, and 2007 and for the three and nine month periods ended September 30, 2010 are included in this filing.

The unaudited pro forma combined financial information is for informational purposes only and is not intended to represent or to be indicative of the combined results of operations or financial position that Vanguard or the pro forma combined company would have reported had the acquisition of the Encore Interests and the Sun TSH, Ward County and Parker Creek acquisitions been completed as of the dates set forth in this unaudited pro forma combined financial information and should not be taken as indicative of Vanguard's future combined results of operations or financial position. The actual results may differ significantly from that reflected in the unaudited pro forma combined financial information for a number of reasons, including, but not limited to, differences between the assumptions used to prepare the unaudited pro forma combined financial information and actual results.

Unaudited Pro Forma Combined
Balance Sheet as of September 30, 2010

(In thousands)	Vanguard historical	Encore historical	Pro forma adjustments (note 2)		Vanguard pro forma combined
Current assets					
	$ 3,234	$ 10,283	$ 193,800	(c),	
Cash and cash equivalents			112,500	(e),	
			(300,000)	(a),	
			(2,750)	(b),	
			(3,550)	(g)	$ 13,517
Trade accounts receivables, net	9,249	16,753	–		26,002
Accounts receivable — affiliates	–	2,628	–		2,628
Derivative assets	21,332	15,078	–		36,410
Other receivables	1,870	–	–		1,870
Other current assets	1,127	697	–		1,824
Total current assets	36,812	45,439	–		82,251
Property and equipment					
Natural gas and oil properties, at cost					
Proved	522,272	856,182	(162,694)	(a)	1,215,760
Unevaluated	–	19	(19)	(a)	–
Accumulated depletion, amortization and accretion	(242,630)	(247,750)	247,750	(a)	(242,630)
Natural gas and oil properties evaluated, net (see Note 1)	279,642	608,451	85,037		973,130
Derivative assets	1,198	10,023	–		11,221
Deferred financing costs	3,110	2,159	(2,159)	(a)	
			2,750	(b)	5,860
Goodwill	–	9,290	(9,290)	(a)	
			407,500	(a)	407,500
Other intangibles, net	–	3,088	5,728	(a)	8,816
Other assets	1,227	464	–		1,691
Total assets	321,989	$ 678,914	$ 489,566		$ 1,490,469
Current liabilities					
Accounts payable — trade	$ 1,086	$ 341	$ –		$ 1,427
Accounts payable — natural gas and oil	2,542	7,946	–		10,488
Payables to affiliates	1,100	2,356			3,456
Deferred swap premium liability	1,643	–	–		1,643
Derivative liabilities	340	5,643	–		5,983
Phantom unit compensation accrual	103	–	–		103
Accrued ad valorem taxes	1,756	11,016	–		12,772
Accrued expenses	768	2,957	–		3,725
Term loan	–	–	175,000	(c)	175,000
Other current liabilities	–	699	–		699
Total current liabilities	9,338	30,958	175,000		215,296
Long-term liabilities					
Long-term debt	170,900	240,000	18,800	(c)	429,700
Derivative liabilities	5,759	9,929	–		15,688
Deferred swap premium liability	432	–	–		432
Asset retirement obligations	5,160	12,950	–		18,110
Deferred taxes	–	39	–		39
Total long-term liabilities	182,251	262,918	18,800		463,969
Members' equity					
Members' capital	128,609	–	112,500	(e)	
			80,000	(f)	
			(3,550)	(g)	317,559
Class B units	5,397	–	–		5,397
Limited partners – public	–	359,940	(359,940)	(d)	–
Limited partners – affiliates	–	26,812	(26,812)	(d)	–
General partner	–	317	(317)	(d)	–
Accumulated other comprehensive income (loss)	(3,606)	(2,031)	2,031	(d)	(3,606)
Noncontrolling interest	–	–	491,854	(a)	491,854

Total members' equity	130,400	385,038	295,766	811,204
Total liabilities and members' equity	$ 321,989	$ 678,914	$ 489,566	$ 1,490,469

Unaudited Pro Forma Combined
Statement of Operations
for the Nine Months Ended September 30, 2010

(In thousands, except per unit amounts)	Vanguard pro forma (note 4)	Encore historical	Pro forma reclassification adjustments (note 3)	Pro forma adjustments (note 3)	Vanguard pro forma combined
Revenues:					
Natural gas, natural gas liquids and oil sales	$ 68,678	$ –	$ 136,140 (a)	$ –	
			207 (b)		
			(96) (b)		$ 204,929
Loss on commodity cash flow hedges	(2,127)	–	–	–	(2,127)
Realized gain on other commodity derivative contracts	18,274	–	9,300 (g)	–	27,574
Unrealized gain on other commodity derivative contracts	1,332	–	5,180 (g)		6,512
Oil revenue	–	114,733	(114,733) (a)	–	–
Natural gas revenue	–	21,407	(21,407) (a)	–	–
Marketing revenue	–	207	(207) (b)	–	–
Total revenues	86,157	136,347	14,384	–	236,888
Costs and Expenses					
Lease operating expenses	14,390	31,701	999 (e)	–	
			(1,890) (d)	–	45,200
Depreciation, depletion, amortization and accretion	17,310	38,472	–	1,920 (n)	57,702
Production taxes and marketing expenses	–	14,157	(13,062) (c)	–	
			(999) (e)	–	
			(96) (b)	–	–
Selling, general and administrative expenses	3,638	10,088	(13) (f)	–	13,713
Production and other taxes	5,215	–	13,062 (c)	–	
			1,890 (d)	–	
			13 (f)	–	
			19 (i)	–	
			(55) (i)	–	20,144
Derivative fair value gain	–	(14,347)	14,347 (g)	–	–
Exploration	–	129	–	(129) (m)	–
Total costs and expenses	40,553	80,200	14,215	1,791	136,759
Income from operations	45,604	56,147	169	(1,791)	100,129
Other income and (expense)					
Interest expense	(4,959)	(9,912)	2,924 (j)	(7,914) (o)	(19,861)
Realized loss on interest rate derivative contracts	(1,408)	–	(2,924) (j)	–	(4,332)
Unrealized loss on interest rate derivative contracts	(2,021)	–	(133) (g)	–	(2,154)
Other income	–	47	–	–	47
Total other expense	(8,388)	(9,865)	(133)	(7,914)	(26,300)
Current income tax benefit (provision)	–	(19)	19 (i)	–	–
Deferred income tax benefit (provision)	–	55	(55) (i)	–	–
Total income taxes	–	36	(36)	–	–
Net income (loss) before noncontrolling interest	37,216	46,318	–	(9,705)	73,829
Income attributable to noncontrolling interest	–	–	–	25,179 (p)	25,179
Net income (loss)	$ 37,216	$ 46,318	$ –	$ (34,884)	$ 48,650
Net income per Common and Class B unit — basic & diluted	$ 1.68				$ 1.63
Weighted average units outstanding					

Common units — basic	21,668	7,760(q)	29,428
Common units — diluted	21,702	7,760(q)	29,462
Class B units — basic & diluted	420		420

Unaudited Pro Forma Combined
Statement of Operations
for the Year Ended December 31, 2009

(In thousands, except per unit amounts)	Vanguard pro forma (note 4)	Encore historical	Pro forma reclassification adjustments (note 3)	Pro forma adjustments (note 3)	Vanguard pro forma combined
Revenues:					
Natural gas, natural gas liquids and oil sales	$ 74,273	$ –	$ 150,039 (a)	$ –	
			478 (b)	–	
			(302)(b)	–	$ 224,488
Loss on commodity cash flow hedges	(2,380)	–	–	–	(2,380)
Realized gain on other commodity derivative contracts	29,993	–	70,221 (g)	–	100,214
Unrealized loss on other commodity derivative contracts	(19,043)	–	(117,733)(g)	–	(136,776)
Oil revenue	–	127,611	(127,611)(a)	–	–
Natural gas revenue	–	22,428	(22,428)(a)	–	–
Marketing revenue	–	478	(478)(b)	–	–
Total revenues	82,843	150,517	(47,814)	–	185,546
Costs and Expenses					
Lease operating expenses	19,271	41,676	1,826 (e)	–	62,773
Depreciation, depletion, amortization and accretion	22,330	56,757	724 (h)	13,251(n)	93,062
Impairment of natural gas and oil properties	105,531	–	–	–	105,531
Production, ad valorem and severance taxes	–	16,099	(16,099)(c)	–	–
Selling, general and administrative expenses	10,644	11,375	645 (k)	–	22,664
Marketing	–	302	(302)(b)	–	–
Production and other taxes	3,845	–	16,099 (c)	–	
			19 (f)	–	
			300 (i)	–	
			(286)(i)	–	19,977
Derivative fair value loss	–	47,464	(47,464)(g)	–	–
Exploration	–	3,132	–	(3,132) (m)	–
Other operating	–	3,099	(1,826)(e)	–	
			(645)(k)	–	
			(724)(h)	–	
			115 (l)	–	
			(19)(f)	–	–
Total costs and expenses	161,621	179,904	(47,637)	10,119	304,007
Loss from operations	(78,778)	(29,387)	(177)	(10,119)	(118,461)
Other income and (expense)					
Interest expense	(5,681)	(10,974)	3,785 (j)	(13,302)(o)	(26,172)
Realized loss on interest rate derivative contracts	(1,903)	–	(3,785)(j)	–	(5,688)
Unrealized gain on interest rate derivative contracts	763	–	48(g)	–	811
Other income	–	46	115 (l)	–	161
Total other income (expense)	(6,821)	(10,928)	163	(13,302)	(30,888)
Current income tax benefit (provision)	–	(300)	300 (i)	–	–
Deferred income tax benefit (provision)	–	286	(286)(i)	–	–
Total income taxes	–	(14)	14	–	–
Net loss before noncontrolling interest	(85,599)	(40,329)	–	(23,421)	(149,349)
Loss attributable to noncontrolling interest	–	–	–	(20,761)(p)	(20,761)
Net loss	$ (85,599)	$ (40,329)	$ –	$ (2,660)	$ (128,588)
Net loss per Common and Class B unit — basic & diluted	$ (3.88)				$ (4.31)
Weighted average units outstanding					
Common units — basic & diluted	21,666			7,760 (q)	29,426
Class B units — basic & diluted	420				420

Notes to Unaudited Pro Forma Combined Financial Information

Note 1Basis of Presentation

On November 16, 2010, Vanguard Natural Resources, LLC (the "Company" or "Vanguard") and its wholly-owned subsidiary, Vanguard Natural Gas, LLC, entered into a Purchase Agreement with Denbury Resources, Inc. ("Denbury"), a Delaware corporation, Encore Partners GP Holdings LLC, a Delaware limited liability company, Encore Partners LP Holdings LLC, a Delaware limited liability company, and Encore Operating, L.P., a Texas limited partnership, pursuant to which it will purchase (i) all of the member interests of Encore Energy Partners GP LLC, a Delaware limited liability company, and (ii) 20,924,055 common units of Encore Energy Partners LP, a Delaware limited partnership ("Encore" or "Partnership"). Vanguard is acquiring 504,851 general partner units which represent a one point one percent (1.10%) interest in the Partnership, and 20,924,055 common units representing limited partner interests, which represent an approximate forty-six percent (46%) interest in the Partnership (collectively the "Encore Interests"), for an aggregate purchase price of $380.0 million (the "Acquisition"). Pursuant to the Purchase Agreement, Vanguard will pay consideration equal to $46.1 million for the general partner units and $333.9 million for the limited partner interests.

Pursuant to the Purchase Agreement, Vanguard may elect to pay up to $80.0 million of the $380.0 million purchase price in Vanguard common units. The price of the Vanguard common units to be issued to Denbury was established at $25.50 per common unit pursuant to the Purchase Agreement. The unaudited pro forma combined financial information assumes that Vanguard has elected to exercise its option in full and anticipates issuing approximately 3.1 million Vanguard common units.

In connection with the Acquisition, Vanguard has entered into a new $175.0 million term loan with some of its lenders under its reserve-based credit facility, which matures in one year from the date of funding ("Newly Committed Term Loan"). The unaudited pro forma combined financial information assumes that Vanguard's Newly Committed Term Loan has been used to effect the transaction described herein, and that the proceeds from the Vanguard common unit offering completed in October 2010, along with the proceeds from additional borrowings under Vanguard's existing reserve-based credit facility will be used as follows (in thousands):

Sources:	
October 2010 offering of common units [1]	$ 112,500
Newly Committed Term Loan [2]	175,000
Borrowings from existing reserve-based credit facility [3]	18,800
Fair value of Vanguard common units to be issued to Denbury [4]	80,000
Total Sources	$ 386,300

Uses:	
Fund cash portion of purchase price	$ 300,000
Fair value of Vanguard common units to be issued to Denbury	80,000
Pay financing and transaction costs	6,300
Total Uses	$ 386,300

(1) Approximate 4.8 million Vanguard common unit offering completed in October 2010. The units were offered to the public at a price of $25.40 per unit. Vanguard received proceeds of approximately $112.5 million from the offering, after deducting underwriting discounts of $5.1 million and paying $3.7 million of the proceeds to redeem 150,000 common units from Vanguard's largest unitholder, but before deducting $0.02 million in expenses.

(2) The $175.0 million Newly Committed Term Loan matures in one year. The lenders will have first lien on the Encore Interests and a second lien on Vanguard's natural gas and oil properties.

(3) Vanguard has a revolving reserve-based credit facility that matures on October 1, 2012 and bears interest based on LIBOR or ABR indications, plus a margin. The reserve-based credit facility is secured by a first lien security interest on all of Vanguard's natural gas and oil properties.

(4) Approximately 3.1 million Vanguard common units at $25.50 per unit. The per unit price was established pursuant to the Purchase Agreement.

Notes (continued)

The accompanying unaudited pro forma combined balance sheet at September 30, 2010 has been prepared to give effect to the Acquisition, the Vanguard common unit offering completed in October 2010, the Vanguard common units to be issued to Denbury and the other financing transactions as if they had occurred on September 30, 2010 and the unaudited pro forma combined statements of operations have been prepared to give effect to the transactions referred to above as if they had occurred on January 1, 2009.

The unaudited pro forma combined financial information includes adjustments to conform Encore's accounting for natural gas and oil properties to the full cost method. Vanguard follows the full cost method of accounting for natural gas and oil properties while Encore follows the successful efforts method of accounting for natural gas and oil properties. Certain costs that are capitalized under the full cost method are expensed under the successful efforts method. These costs consist primarily of unsuccessful exploration drilling costs, geological and geophysical costs, delay rental on leases, abandonment costs and general and administrative expenses directly related to exploration and development activities. Under the successful efforts method of accounting, proved property acquisition costs are amortized on a unit-of-production basis over total proved reserves and costs of wells, related equipment and facilities are depreciated over the life of the proved developed reserves that will utilize those capitalized assets on a field-by-field basis. Under the full cost method of accounting, property acquisition costs, costs of wells, related equipment and facilities and future development costs are included in a single full cost pool, which is amortized on a unit-of-production basis over total proved reserves.

Vanguard's unaudited pro forma statements of operations, which are included in the unaudited pro forma combined statements of operations, also include the pro forma effects of the Sun TSH, Ward County and Parker Creek acquisitions of natural gas and oil properties completed during 2009 and 2010 and the related equity financings as if they had occurred on January 1, 2009. Vanguard’s Sun TSH, Ward County and Parker Creek acquisitions are unrelated to the acquisition of the Encore Interests. The pro forma effects of the Sun TSH, Ward County and Parker Creek acquisitions are presented in Note 4 to the unaudited pro forma combined financial information.

Notes (continued)

Note 2 Unaudited Pro forma Combined Balance Sheet

The Acquisition will be accounted for using the acquisition method of accounting as Vanguard obtains control upon the closing of the Acquisition. Vanguard will receive carryover tax basis in Encore's assets and liabilities because the Acquisition will not be a taxable transaction under the United States Internal Revenue Code. The consideration to be paid, the fair value of Vanguard’s common units to be issued to Denbury and the estimated market value of the noncontrolling interest of Encore was assigned to the assets acquired and liabilities assumed based on a preliminary assessment of the estimated fair value of the assets acquired and liabilities assumed at September 30, 2010 using currently available information. Vanguard expects to close the Acquisition as soon as practicable. The final purchase price allocation and the resulting effect on results of operations and financial position may significantly differ from the pro forma amounts included herein.

The purchase price allocation is preliminary and subject to change due to several factors, including:

- changes in the estimated fair values of Encore's assets and liabilities as of the Acquisition date, which could result from changes in expected future product prices, changes in reserve estimates as well as other changes;

- the tax basis of Encore's assets and liabilities at the Acquisition date;

- changes in the estimated market value of the noncontrolling interest of Encore resulting from changes in Encore’s common unit price at the Acquisition closing date; and

- changes in the estimated fair value of the Vanguard common unit consideration transferred depending on its estimated fair value at the date of closing.

Notes (continued)

The consideration to be transferred and noncontrolling interest, fair value of assets acquired and liabilities assumed and resulting goodwill were calculated as follows (in thousands):

Pro forma consideration and noncontrolling interest	
Cash payment to acquire Encore Interests	$ 300,000
Market value of Vanguard's common units to be issued to Denbury[(1)]	80,000
Market value of noncontrolling interest of Encore [(2)]	491,854
Pro forma consideration and noncontrolling interest of Encore	$ 871,854
Add: fair value of liabilities assumed	
Accounts payable and accrued liabilities	$ 14,314
Natural gas and oil payable	7,946
Current derivative liabilities	5,643
Other current liabilities	3,055
Long-term debt	240,000
Asset retirement obligations	12,950
Long-term derivative liabilities	9,929
Long-term deferred tax liability	39
Amount attributable to liabilities assumed	$ 293,876
Less: fair value of assets acquired	
Cash	$ 10,283
Trade and other receivables	16,753
Current derivative assets	15,078
Other current assets	3,325
Natural gas and oil properties — proved	693,488
Long-term derivative assets	10,023
Other long-term assets	9,280
Amount attributable to assets acquired	$ 758,230
Goodwill	$ 407,500

(1) Approximately 3.1 million Vanguard common units at $25.50 per unit will be issued to Denbury to acquire the Encore Interests. The per unit price was established pursuant to the Purchase Agreement. For every dollar that the market value of Vanguard's unit price increases (decreases), goodwill would increase (decrease) by $3.1 million.

(2) Represents approximate market value of the noncontrolling interest of Encore assuming 24.4 million Encore common units are outstanding to public unitholders (based on Encore common units outstanding as of November 30, 2010) at $20.19 per Encore common unit (closing price as of November 30, 2010).

Notes (continued)

Goodwill is measured as the excess of the fair value of the consideration transferred plus the estimated market value of the noncontrolling interest of Encore over the acquisition-date estimated fair value of the assets acquired less liabilities assumed.
The market value of the noncontrolling interest of Encore was calculated using the Encore closing common unit price on November 30, 2010 of $20.19. If Encore's common unit price were to increase (decrease) by $1.00, goodwill would increase (decrease) by $24.4 million.

Pro Forma Adjustments to the Unaudited Pro Forma Combined Balance Sheet

(a) Represents pro forma adjustments to:

- reflect the consideration to be paid and the estimated market value of the noncontrolling interest of Encore and adjust the assets acquired and liabilities assumed to their estimated fair values as of the closing date;

- eliminate Encore's historical goodwill and accumulated depreciation, depletion and amortization balances; and

- eliminate deferred financing costs on Encore's credit facilities.

(b) Represents the new deferred financing costs attributable to the Newly Committed Term Loan.

(c) Represents Vanguard's borrowings under the Newly Committed Term Loan and borrowings under Vanguard's existing reserve-based credit facility. Assumes Vanguard's pro forma debt will consist of the following (in thousands):

New Financing	
Newly Committed Term Loan	$ 175,000
Borrowings under Vanguard's existing reserve-based credit facility	18,800
Vanguard's Existing Debt	
Reserve-based credit facility	170,900
Encore's Existing Debt	
Encore's revolving credit facility	240,000
Total combined debt	604,700
Less current obligations	(175,000)
Pro forma combined long-term debt	$ 429,700

(d) Represents the elimination of Encore's historical equity in connection with the acquisition method of accounting.

(e) Represents the approximate 4.8 million Vanguard common unit offering completed in October 2010. The units were offered to the public at a price of $25.40 per unit. Vanguard received proceeds of approximately $112.5 million from the offering, after deducting underwriting discounts of $5.1 million and paying $3.7 million of the proceeds to redeem 150,000 common units from Vanguard's largest unitholder, but before deducting $0.02 million in expenses.

(f) Represents the increase in Vanguard's common units resulting from the issuance of Vanguard's common units to Denbury to effect the Acquisition as follows:

Vanguard common units issued	3,137,255
Price of Vanguard common units[(1)]	$ 25.50
Fair value of common units issued	$ 80,000,000

(1) Represents the price established pursuant to the Purchase Agreement.

Notes (continued)

(g) Represents the estimated $3.6 million of legal and advisory fees to be incurred by Vanguard not reflected in the September 30, 2010 balance sheets, that are not capitalizable as part of the transaction. These costs are reflected in the unaudited pro forma combined balance sheet as a reduction of equity as the costs will be expensed by Vanguard as incurred.

Reclassifications were made to the historical Encore assets and liabilities to conform to Vanguard’s presentation. Those reclassifications did not impact the total historical Encore assets or liabilities.

Note 3 Unaudited Pro Forma Combined Statements of Operations

Adjustments (a) — (l) to the unaudited pro forma combined statement of operations for the nine months ended September 30, 2010 and the year ended December 31, 2009 include reclassifications required to conform Encore's revenue and expense items to Vanguard's presentation as follows:

(a) Represents the reclassification of Encore's natural gas and oil product sales to conform to Vanguard's presentation.

(b) Represents the reclassification of marketing revenue and marketing expenses to conform to Vanguard's presentation.

(c)Represents the reclassification of production and severance taxes to “Production and other taxes” to conform to Vanguard's presentation.

(d) Represents the reclassification of ad valorem taxes to “Production and other taxes” to conform to Vanguard's presentation.

(e) Represents the reclassification of transportation costs to “Lease operating expenses” to conform to Vanguard's presentation.

(f) Represents the reclassification of annual corporate taxes to “Production and other taxes” to conform to Vanguard's presentation.

(g) Represents the reclassification of (1) settlements of natural gas and oil derivatives to “Realized gain on other commodity derivative contracts,” (2) the change in fair value of natural gas and oil derivatives to “Unrealized gain (loss) on other commodity derivative contracts” and (3) the change in fair value of interest rate derivatives to “Unrealized gain (loss) on interest rate derivative contracts” to conform to Vanguard’s presentation.

(h) Represents the reclassification of accretion expense on Encore's asset retirement obligations to “Depreciation, depletion amortization and accretion” expense to conform to Vanguard's presentation.

(i) Represents the reclassification of current and deferred income tax benefit (provision) to “Production and other taxes” to conform to Vanguard's presentation.

(j) Represents the reclassification of settlements of interest rate derivatives to “Realized loss on interest rate derivative contracts” to conform to Vanguard's presentation.

(k) Represents the reclassification of bad debt expense to “Selling, general and administrative expenses” to conform to Vanguard's presentation.

(l) Represents the reclassification of gains on sales of other assets to “Other income” to conform to Vanguard's presentation.

Notes (continued)

Adjustments (m) — (q) to the unaudited pro forma combined statements of operations for the nine months ended September 30, 2010 and the year ended December 31, 2009 are to reflect the Acquisition, the Vanguard common unit offering completed in October 2010, other anticipated financing transactions and the conversion of Encore's method of accounting for natural gas and oil properties from the successful efforts method of accounting to the full cost method of accounting.

(m) Represents the capitalization of unsuccessful exploration costs, geological and geophysical costs and delay rentals attributable to the development of natural gas and oil properties in accordance with the full cost method of accounting for natural gas and oil properties.

(n) Represents the change in depreciation, depletion and amortization primarily resulting from the pro forma calculation of the combined entity's depletion expense under the full cost method of accounting for natural gas and oil properties. The pro forma depletion adjustment utilizes a depletion rate of $14.56 per BOE for the nine months ended September 30, 2010 and $15.01 per BOE for the year ended December 31, 2009.

(o) Represents the adjustment to interest expense for the Newly Committed Term Loan as follows (in thousands):

	Nine months ended September 30, 2010	Year ended December 31, 2009
Pro forma increase in cash interest expense due to:		
Vanguard's Newly Committed Term Loan	$ 7,560	$ 10,080
Borrowings under Vanguard’s existing reserve-based credit facility	354	472
Pro forma increase to noncash interest expense due to:		
Amortization of deferred financing costs of Vanguard's Newly Committed Term Loan	–	2,750
Pro forma increase to interest expense	$ 7,914	$ 13,302

Pro forma borrowings at September 30, 2010 under the Newly Committed Term Loan are $175.0 million. Interest on the Newly Committed Term Loan is variable at LIBOR plus 5.5%. Pro forma interest expense under the Newly Committed Term Loan assumes an interest rate of 5.76% which was calculated using LIBOR rates at November 3, 2010. Each 1/8% fluctuation in the term loan interest rate would change pro forma interest expense by approximately $0.2 million for the nine months ended September 30, 2010 and for the year ended December 31, 2009.

Pro forma borrowings at September 30, 2010 under the Vanguard’s existing reserve-based credit facility are $189.7 million. Interest on Vanguard’s existing reserve-based credit facility is variable at LIBOR plus 2.25%. Pro forma interest expense under Vanguard’s existing reserve-based credit facility assumes an interest rate of 2.51% which was calculated using LIBOR rates at November 3, 2010. Each 1/8% fluctuation in the term loan interest rate would change pro forma interest expense by approximately $0.02 million for the nine months ended September 30, 2010 and for the year ended December 31, 2009.

(p) Represents the allocable portion of Encore’s historical net income (loss) and impact of adjustments (m) and (n) to earnings relating to the noncontrolling interest of Encore.

(q) Reflects units sold in the Vanguard common unit offering completed in October 2010, a portion of the proceeds were used to redeem 150,000 common units from Vanguard’s largest unitholder and the remaining proceeds will be used to fund a portion of the purchase price of the Encore Interests and units to be issued to Denbury in the Acquisition.

Notes (continued)

Note 4 Vanguard's Unaudited Pro forma Consolidated Statements of Operations

Vanguard's unaudited pro forma consolidated statements of operations included in the unaudited pro forma combined statements of operations give effect to the following transactions as if they had occurred on January 1, 2009:

Acquisition of natural gas and oil properties located in the Sun TSH Field. On July 17, 2009, Vanguard entered into a Purchase and Sale Agreement with Segundo Navarro Drilling, Ltd., a wholly-owned subsidiary of Lewis Energy Group, for the acquisition of certain natural gas and oil properties located in the Sun TSH Field in La Salle County, Texas. Vanguard refers to this acquisition as the “Sun TSH acquisition.” The purchase price for said assets was $52.3 million with an effective date of July 1, 2009. Vanguard completed this acquisition on August 17, 2009 for an adjusted purchase price of $50.5 million. The adjusted purchase price of $50.5 million considered purchase price adjustments of approximately $1.8 million. This acquisition was funded with borrowings under Vanguard’s reserve-based credit facility and proceeds from the public equity offering of 3.9 million Vanguard common units completed on August 17, 2009.

Acquisition of natural gas and oil properties located in Ward County. On November 27, 2009, Vanguard entered into a Purchase and Sale Agreement, Lease Amendment and Lease Royalty Conveyance Agreement and a Conveyance Agreement to acquire certain producing natural gas and oil properties located in Ward County, Texas in the Permian Basin from private sellers, referred to as the “Ward County acquisition.” This transaction had an effective date of October 1, 2009 and was closed on December 2, 2009 for $55.0 million. This acquisition was initially funded with borrowings under Vanguard’s reserve-based credit facility with borrowings being reduced by $40.3 million shortly thereafter with the proceeds from a 2.6 million Vanguard common unit offering.

Acquisition of natural gas and oil properties located in Mississippi, Texas and New Mexico. On April 30, 2010, Vanguard entered into a definitive agreement with a private seller for the acquisition of certain natural gas and oil properties located in Mississippi, Texas and New Mexico. Vanguard refers to this acquisition as the “Parker Creek acquisition.” The purchase price for said assets was $113.1 million with an effective date of May 1, 2010. Vanguard completed this acquisition on May 20, 2010. The adjusted purchase price of $114.3 million considered final purchase price adjustments of approximately $1.2 million. The purchase price was funded from the approximate $71.5 million in net proceeds from Vanguard’s May 2010 equity offering and with borrowings under Vanguard’s existing reserve-based credit facility.

Notes (continued)

Vanguard Unaudited Pro Forma
Consolidated Statement of Operations
for the Nine Months Ended September 30, 2010

(In thousands, except per unit amounts)	Vanguard historical	Pro forma adjustments		Vanguard pro forma
Revenues:				
Natural gas, natural gas liquids and oil sales	$ 62,200	$ 6,478	(a)	$ 68,678
Loss on commodity cash flow hedges	(2,127)	–		(2,127)
Realized gain on other commodity derivative contracts	18,274	–		18,274
Unrealized gain on other commodity derivative contracts	1,332	–		1,332
Total revenues	79,679	6,478		86,157
Costs and Expenses				
Lease operating expenses	13,545	845	(b)	14,390
Depreciation, depletion, amortization and accretion	16,130	1,180	(c)	17,310
Selling, general and administrative expenses	3,638	–		3,638
Production and other taxes	5,215	–		5,215
Total costs and expenses	38,528	2,025		40,553
Income from operations	41,151	4,453		45,604
Other expense				
Interest expense	(4,522)	(437)	(d)	(4,959)
Realized loss on interest rate derivative contracts	(1,408)	–		(1,408)
Unrealized loss on interest rate derivative contracts	(2,021)	–		(2,021)
Loss on acquisition of natural gas and oil properties	(5,680)	5,680	(e)	–
Total other expense	(13,631)	5,243		(8,388)
Net income	$ 27,520	$ 9,696		$ 37, 216
Net income per Common and Class B unit — basic	$ 1.35			$ 1.68
Net income per Common and Class B unit — diluted	$ 1.34			$ 1.68
Weighted average units outstanding				
Common units — basic	20,037	1,631	(f)	21,668
Common units — diluted	20,071	1,631	(f)	21,702
Class B units — basic & diluted	420			420

Notes (continued)

Vanguard Unaudited Pro Forma Consolidated Statement of Operations for the Year Ended December 31, 2009

(In thousands, except per unit amounts)	Vanguard historical	Pro forma adjustments		Vanguard pro forma
Revenues:				
Natural gas, natural gas liquids and oil sales	$ 46,035	$ 28,238	(g)	$ 74,273
Loss on commodity cash flow hedges	(2,380)	–		(2,380)
Realized gain on other commodity derivative contracts	29,993	–		29,993
Unrealized gain on other commodity derivative contracts	(19,043)	–		(19,043)
Total revenues	54,605	28,238		82,843
Costs and Expenses				
Lease operating expenses	12,652	6,619	(h)	19,271
Depreciation, depletion, amortization and accretion	14,610	7,720	(i)	22,330
Impairment of natural gas and oil properties	110,154	(4,623)	(j)	105,531
Selling, general and administrative expenses	10,644	–		10,644
Production and other taxes	3,845	–		3,845
Total costs and expenses	151,905	9,716		161,621
Income from operations	(97,300)	18,522		(78,778)
Other income and (expense)				
Interest expense	(4,276)	(1,405)	(k)	(5,681)
Realized loss on interest rate derivative contracts	(1,903)	–		(1,903)
Unrealized loss on interest rate derivative contracts	763	–		763
Gain on acquisition of natural gas and oil properties	6,981	(6,981)	(l)	–
Total other income	1,565	(8,386)		(6,821)
Net income (loss)	$ (95,735)	$ 10,136		$ (85,599)
Net income per Common and Class B unit — basic & diluted	$ (6.74)			$ (3.88)
Weighted average units outstanding				
Common units — basic & diluted	13,791	7,875	(m)	21,666
Class B units — basic & diluted	420			420

Notes (continued)

Vanguard's unaudited pro forma consolidated statements of operations include the following adjustments:

(a) Represents the increase in natural gas, natural gas liquids and oil sales resulting from the Parker Creek acquisition of natural gas and oil properties completed during 2010.

(b) Represents the increase in lease operating expenses resulting from the Parker Creek acquisition of natural gas and oil properties completed during 2010.

(c) Represents the increase in depreciation, depletion, amortization and accretion resulting from the Parker Creek acquisition of natural gas and oil properties completed during 2010.

(d) Represents the pro forma interest expense related to borrowings under Vanguard's reserve-based credit facility to fund the Parker Creek acquisition completed during 2010.

(e) Represents the nonrecurring loss on acquisition of natural gas and oil properties related to the Parker Creek acquisition completed during 2010.

(f) Represents the pro forma adjustment for the Vanguard common units sold in connection with the funding of the Parker Creek acquisition completed during 2010.

(g) Represents the increase in natural gas, natural gas liquids and oil sales resulting from the Sun TSH, Ward County and Parker Creek acquisitions of natural gas and oil properties completed during 2009 and 2010.

(h) Represents the increase in lease operating expenses resulting from the Sun TSH, Ward County and Parker Creek acquisitions of natural gas and oil properties completed during 2009 and 2010.

(i) Represents the increase in depreciation, depletion, amortization and accretion resulting from the Sun TSH, Ward County and Parker Creek acquisitions of natural gas and oil properties completed during 2009 and 2010.

(j) Represents the decrease in impairment of natural gas and oil properties resulting from the increase in 2009 depletion from the Sun TSH and Ward County acquisitions of natural gas and oil properties completed during 2009.

(k) Represents the pro forma interest expense related to borrowings under Vanguard's reserve-based credit facility to fund the Ward County and Parker Creek acquisitions completed during 2009 and 2010.

(l) Represents the nonrecurring gain on acquisition of natural gas and oil properties related to the Sun TSH and Ward County acquisitions completed during 2009.

(m) Represents the pro forma adjustment for the Vanguard common units sold in connection with the funding of the Sun TSH, Ward County and Parker Creek acquisitions completed during 2009 and 2010.

Exhibit 99.4

Summary Pro Forma Combined
Natural Gas, Oil and Natural Gas Liquids
Reserve Data

The following tables set forth summary pro forma information with respect to Vanguard's and Encore's pro forma combined estimated net proved and proved developed natural gas, oil and natural gas liquids reserves as of December 31, 2009. This pro forma information gives effect to the acquisition of the Encore Interests as if it occurred on December 31, 2009. The Vanguard pro forma combined reserves include the noncontrolling interest in the Encore reserves of approximately 53.2% at December 31, 2009. Future exploration, exploitation and development expenditures, as well as future commodity prices and service costs, will affect the reserve volumes attributable to the acquired properties and the standardized measure of discounted future net cash flows.

Estimated quantities of natural gas, oil and natural gas liquids reserves as of December 31, 2009

	Gas (MMcf)		
	Vanguard historical	**Encore historical**	**Vanguard pro forma combined**
Net proved reserves			
January 1, 2009	81,237	78,011	159,248
Revisions of previous estimates	(36,569)	(7,164)	(43,733)
Extensions, discoveries and other	3,191	1,112	4,303
Purchases of reserves in place	39,832	18,837	58,669
Production	(4,542)	(6,097)	(10,639)
December 31, 2009	83,149	84,699	167,848

	Oil and Natural Gas Liquids (MBbls)		
	Vanguard historical	**Encore historical**	**Vanguard pro forma combined**
Net proved reserves			
January 1, 2009	4,547	27,278	31,825
Revisions of previous estimates	–	3,987	3,987
Extensions, discoveries and other	66	2	68
Purchases of reserves in place	5,810	–	5,810
Production	(460)	(2,337)	(2,797)
December 31, 2009	9,963	28,930	38,893

	Vanguard historical	**Encore historical**	**Vanguard pro forma combined**
Estimated proved reserves:			
Natural Gas (MMcf)	83,149	84,699	167,848
Oil and Natural Gas Liquids (MBbls)	9,963	28,930	38,893
MBOE	23,821	43,047	66,868
Estimated proved developed reserves:			
Natural Gas (MMcf)	54,129	78,379	132,508
Oil and Natural Gas Liquids (MBbls)	7,126	26,341	33,467
MBOE	16,148	39,404	55,552

The standardized measure of discounted future net cash flows relating to the combined proved gas, oil and natural gas liquids reserves at December 31, 2009 is as follows (in thousands):

	Vanguard historical	Encore historical	Vanguard pro forma combined	
Future cash inflows	$ 846,196	$ 1,879,504	$ 2,725,700	
Future production costs	(362,386)	(819,352)	(1,181,738)	
Future development costs	(95,297)	(46,852)	(142,149)	
Future abandonment costs, net of salvage	–	(29,339)	(29,339)	
Future net income tax expense	–	(1,217)	(1,217)	
Future net cash flows	388,513	982,744	1,371,257	
10% annual discount for estimated timing of cash flows	(209,840)	(488,243)	(698,083)	
Standardized measure of discounted future net cash flows	$ 178,673	$ 494,501	$ 673,174	(a)

(a) The total Vanguard pro forma combined standardized measure includes approximately $263.1 million attributable to the noncontrolling interest of Encore.

For the December 31, 2009 calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves were computed using the average natural gas and oil price based upon the 12-month average price of $3.87 and $3.83 per MMBtu for natural gas and $ 61.04 and $61.18 per barrel of crude oil for Vanguard and Encore historical, respectively, adjusted for quality, transportation fees and a regional price differential.

The following are the principal sources of change in the combined standardized measure of discounted future net cash flows (in thousands):

	Vanguard historical	Encore historical	Vanguard pro forma combined	
Sales and transfers, net of production costs	$ (29,313)	$ (95,270)	(124,583)	
Net changes in prices and production costs	(21,697)	153,083	131,386	
Extensions discoveries and improved recovery, less related costs	1,673	1,588	3,261	
Changes in estimated future development costs	2,557	(3,527)	(970)	
Previously estimated development costs incurred during the period	5,825	4,732	10,557	
Revision of previous quantity estimates	(64,155)	65,300	1,145	
Accretion of discount	19,007	32,662	51,669	
Purchases of reserves in place	80,776	19,136	99,912	
Net change in income taxes	–	(457)	(457)	
Change in production rates, timing and other	(6,073)	(9,368)	(15,441)	
Net change in standardized measure	$ (11,400)	$ 167,879	$ 156,479	
Standardized measure, January 1, 2009	190,073	326,622	516,695	
Standardized measure, December 31, 2009	$ 178,673	$ 494,501	$ 673,174	(a)

(a) The total Vanguard pro forma combined standardized measure includes approximately $263.1 million attributable to the noncontrolling interest of Encore.