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

FORM 8-K/A

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report: September 13, 2007
(Date of earliest event reported: July 25, 2007)

Constellation Energy Partners LLC
(Exact name of registrant as specified in its charter)

Delaware	**001-33147**	**11-3742489**
(State or other jurisdiction of incorporation)	**(Commission File Number)**	**(IRS Employer Identification No.)**

111 Market Place Baltimore, MD	**21202**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (410) 468-3500

Not applicable
(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))

On July 26, 2007, the Company filed a Current Report on Form 8-K (the "Report") in connection with its acquisition of certain oil and gas properties via an agreement of merger (the "Merger Agreement") providing for the merger of Amvest Osage, Inc. ("Amvest" or "Amvest Osage") with and into a wholly-owned subsidiary of the Company for an aggregate purchase price of approximately $240 million, subject to purchase price adjustments (the "Amvest Acquisition"). The description of the Amvest Acquisition and terms of the Merger Agreement contained in the Company's 8-K filed on July 16, 2007 are incorporated herein by reference. A copy of the Merger Agreement was filed as Exhibit 2.1 on Form 8-K on July 26, 2007 and is incorporated herein by reference. The Current Report on Form 8-K filed July 26, 2007 is being amended by this Amendment No. 1 to include the required historical financial statements and other financial information with respect to the Amvest Acquisition as required by Item 9.01 (a) and the pro forma financial information required by Item 9.01 (b). Financial statements are being provided for Amvest Osage.

This Report replaces Item 9.01 of that filing:

Item 9.01 Financial Statements and Exhibits.

(a) Financial Statements of businesses acquired.

The following information is included as an exhibit to this report as noted in (d) below:

1. Amvest Osage audited financial statements for the years ended July 31, 2006, July 31, 2005, and July 31, 2004, and the unaudited interim nine month periods ended April 30, 2007 and April 30, 2006.

(b) Pro Forma Financial Information.

The following unaudited pro forma condensed combined financial statements reflect the combination of the historical consolidated balance sheets and income statements of Constellation Energy Partners LLC, Amvest and certain other acquisitions, adjusted for certain effects of the acquisition, the related funding, and for different fiscal year-ends:

1. Unaudited Pro Forma Condensed Combined Balance Sheet

2. Unaudited Pro Forma Condensed Combined Statement of Operations

3. Notes to Unaudited Pro Forma Condensed Combined Financial Statements

4. Unaudited Pro Forma Combined Supplemental Oil and Gas Disclosures

(c) Not Applicable.

(d) Exhibits.

Exhibit Number	Description
99.1	The audited financial statements of Amvest Osage for the years ended July 31, 2006, July 31, 2005, and July 31, 2004, and the unaudited interim financial statements of Amvest Osage for the nine months ended April 30, 2007 and April 30, 2006.
99.2	The unaudited pro forma condensed balance sheet of Constellation Energy Partners LLC as of June 30, 2007, which gives effect to the Amvest Acquisition as if it had occurred on June 30, 2007 and the unaudited pro forma condensed combined statement of operations for the year ended December 31, 2006 and for the six months ended June 30, 2007, which give effect to the Amvest Acquisition and certain other acquisitions as if they occurred on January 1, 2006.

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 hereunto duly authorized.

CONSTELLATION ENERGY PARTNERS LLC

Date: September 13, 2007

By: /s/ Angela A. Minas
Angela A. Minas
Chief Financial Officer

EXHIBIT INDEX

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AMVEST OSAGE, INC.
AND SUBSIDIARIES

Consolidated Financial Statements for the Years ended July 31, 2006, 2005, and 2004, together with the Independent Auditors' Report, and Consolidated Condensed Financial Statements for the Nine Months ended April 30, 2007 and 2006 (Unaudited)

INDEPENDENT AUDITORS' REPORT

To the Stockholder of
AMVEST Osage, Inc.
Charlottesville, Virginia

We have audited the accompanying consolidated balance sheets of AMVEST Osage, Inc. and subsidiaries (the Company) as of July 31, 2006 and 2005, and the related consolidated statements of income, stockholder's equity, and cash flows for each of the three years in the period ended July 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the companies as of July 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended July 31, 2006 in conformity with accounting principles generally accepted in the United States of America.

Our audits were conducted for the purpose of forming an opinion on the basic financial statements taken as a whole. The supplemental information in Note 11 to the consolidated financial statements is presented for the purpose of additional analysis and is not a required part of the basic financial statements. This additional information is the responsibility of the Company's management. Such information has not been subjected to the auditing procedures applied in our audits of the basic financial statements, and accordingly, we express no opinion on it.

Deloitte & Touche LLP
Richmond, Virginia

September 13, 2007

AMVEST OSAGE, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (In thousands)

	April 30, 2007 (Unaudited)	July 31, 2006	July 31, 2005
ASSETS			
CURRENT ASSETS			
Cash	$ 3	$ 3	$ 3
Affiliate cash pool	—	1,050	748
Accounts receivable	3,982	4,711	3,581
Parts inventory	1,808	1,759	1,379
Prepaid assets	166	125	163
Deferred income taxes	—	—	17
	5,959	7,648	5,891
PROPERTY AND EQUIPMENT			
Equipment	1,444	1,337	1,214
Land	407	407	372
Buildings	412	412	172
Oil and gas properties (successful efforts)	124,180	102,134	78,468
	126,443	104,290	80,226
Accumulated depreciation, depletion and amortization	(26,414)	(18,965)	(11,767)
	100,029	85,325	68,459
DEPOSITS	12	12	28
TOTAL ASSETS	$ 106,000	$ 92,985	$ 74,378
LIABILITIES AND STOCKHOLDER'S EQUITY			
CURRENT LIABILITIES			
Accounts payable	$ 2,014	$ 2,271	$ 1,292
Accrued royalties	1,692	1,540	1,313
Accrued expenses	922	803	785
Affiliate cash pool	6,715	—	—
Due to affiliates	24,682	29,096	23,991
Deferred income taxes	82	72	—
	36,107	33,782	27,381
DEFERRED INCOME TAXES	23,259	18,161	13,038
RECLAMATION OBLIGATIONS	864	763	701
TOTAL LIABILITIES	60,230	52,706	41,120
COMMITMENTS AND CONTINGENCIES, note 7			
STOCKHOLDER'S EQUITY			
Common stock	—	—	—
Additional paid-in capital	27,267	26,807	26,500
Retained earnings	18,503	13,472	6,758
TOTAL STOCKHOLDER'S EQUITY	45,770	40,279	33,258
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	$ 106,000	$ 92,985	$ 74,378

See accompanying notes to consolidated financial statements.

AMVEST OSAGE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME (In thousands)

	Nine Months Ended April 30, 2007 (Unaudited)	Nine Months Ended April 30, 2006 (Unaudited)	Year Ended July 31, 2006	Year Ended July 31, 2005	Year Ended July 31, 2004
REVENUES					
Net sales	$ 27,955	$ 30,912	$39,808	$26,812	$16,575
Gain/(loss) on mark-to-market activities	—	150	150	(150)	—
TOTAL REVENUES	27,955	31,062	39,958	26,662	16,575
EXPENSES					
Operating expenses:					
Lease operating expenses	5,628	4,455	6,237	5,313	4,000
Cost of Sales	1,111	1,076	1,476	1,382	850
Production taxes	1,633	1,820	2,341	1,461	872
General and administrative	3,483	3,219	4,581	3,172	2,778
Depreciation, depletion, and amortization	7,619	5,362	7,363	5,335	3,336
Accretion expense	32	32	42	36	29
Total operating expenses	19,506	15,964	22,040	16,699	11,865
Other expense (income):					
Affiliate interest expense	1,183	594	844	573	148
Interest income	—	(1)	(1)	(1)	—
Other expense (income)	(46)	1	1	(2)	(21)
Total other expense, net	1,137	594	844	570	127
INCOME BEFORE INCOME TAXES	7,312	14,504	17,074	9,393	4,583
INCOME TAX PROVISION					
Current	(2,827)	2,380	1,148	(2,565)	(205)
Deferred	5,108	2,890	5,212	5,410	1,508
	2,281	5,270	6,360	2,845	1,303
NET INCOME	$ 5,031	$ 9,234	$10,714	$ 6,548	$ 3,280

See accompanying notes to consolidated financial statements.

AMVEST OSAGE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (In thousands)

	Nine Months Ended April 30, 2007 (Unaudited)	Nine Months Ended April 30, 2006 (Unaudited)	Year Ended July 31, 2006	Year Ended July 31, 2005	Year Ended July 31, 2004
OPERATING ACTIVITIES					
Net income	$ 5,031	$ 9,234	$ 10,714	$ 6,548	$ 3,280
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATIONS:					
Deferred income taxes	5,108	2,890	5,212	5,410	1,508
Depreciation, depletion, and amortization	7,619	5,362	7,363	5,335	3,336
(Gains) / loss on sale of property	(22)	4	5	—	(7)
Bad debt expense and other	—	—	—	(6)	(11)
Accretion expense	32	32	42	36	29
Stock appreciation rights	460	188	307	—	
CHANGES IN ASSETS AND LIABILITIES:					
Accounts receivable	729	97	(1,130)	(1,005)	(690)
Parts inventory	(49)	(206)	(380)	(528)	(233)
Prepaid Expenses	(41)	19	38	(75)	(69)
Deposits	—	16	16	1	(1)
Accounts payable	(161)	104	432	(14)	71
Accrued royalties	152	120	227	485	247
Accrued expenses	119	(20)	18	494	11
Reclamation obligations settled	—	(36)	(207)	(19)	(21)
CASH PROVIDED BY OPERATING ACTIVITIES	18,977	17,804	22,657	16,662	7,450
INVESTING ACTIVITIES					
Affiliate cash pool, net	1,050	748	(302)	(620)	(21)
Acquisition of oil and gas properties	—	—	(7,038)	—	—
Capital expenditures	(22,378)	(17,045)	(22,689)	(25,414)	(17,709)
Proceeds from disposal of property	50	6,083	6,267	301	19
CASH USED IN INVESTING ACTIVITIES	(21,278)	(10,214)	(23,762)	(25,733)	(17,711)
FINANCING ACTIVITIES					
Due to affiliates, net	(4,414)	(13,663)	1,105	9,071	10,260
Affiliate cash pool, net	6,715	6,073	—	—	—
CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	2,301	(7,590)	1,105	9,071	10,260
INCREASE (DECREASE) IN CASH	—	—	—	—	(1)
CASH, beginning of year	3	3	3	3	4
CASH, end of year	$ 3	$ 3	$ 3	$ 3	$ 3

See accompanying notes to consolidated financial statements.

AMVEST OSAGE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDER'S EQUITY (In thousands)

	COMMON STOCK *	ADDITIONAL PAID-IN CAPITAL	RETAINED EARNINGS	TOTAL
Balance at August 1, 2003	$ —	$ 26,500	$ (3,070)	$23,430
Net income	—	—	3,280	3,280
Balance at July 31, 2004	—	26,500	210	26,710
Net income	—	—	6,548	6,548
Balance at July 31, 2005	—	26,500	6,758	33,258
Net income	—	—	10,714	10,714
Capital contribution	—	307	—	307
Dividends paid	—	—	(4,000)	(4,000)
Balance at July 31, 2006	—	26,807	13,472	40,279
Net income (unaudited)	—	—	5,031	5,031
Capital contribution (unaudited)	—	460	—	460
Balance at April 30, 2007 (unaudited)	$ —	$ 27,267	$ 18,503	$45,770

* 100 shares issued and outstanding at $1 par value, 1,000 shares authorized.

See accompanying notes to consolidated financial statements.

1. Summary of Significant Accounting Policies

Nature of Business

AMVEST Osage, Inc. is an oil and gas company formed in September 2000 for the purpose of developing and operating oil and gas reserves in Oklahoma. The company owns and operates 343 natural gas wells in Osage County, Oklahoma under a concession from the Osage Nation covering approximately 560,000 net acres. AMVEST Osage, Inc.'s wholly owned subsidiaries include Northeast Shelf Energy, LLC and Mid-Continent Oilfield Supply, LLC (collectively the Company).

The Company was a wholly owned subsidiary of AMVEST Corporation (AMVEST) through the date of the transaction described in Note 10.

Unaudited Consolidated Financial Statements for the Nine Months ended April 30, 2007 and 2006

As permitted by the rules and regulations of the Securities and Exchange Commission (SEC), the accompanying unaudited consolidated financial statements contain certain condensed financial information and exclude certain footnote disclosures normally included in annual audited consolidated financial statements prepared in accordance with accounting principles generally accepted in the United States of America. In the opinion of the Company's management, the accompanying unaudited consolidated financial statements contain all adjustments, including normal recurring accruals, necessary to present fairly the Company's financial position as of April 30, 2007, and the results of its operations and cash flows for the nine months ended April 30, 2007 and 2006. The results of operations for the nine months ended April 30, 2007 are not necessarily indicative of the results expected for the full year.

Principles of Consolidation and Reporting

The consolidated financial statements of the Company include the accounts of AMVEST Osage, Inc. and its subsidiaries. All intercompany transactions have been eliminated in consolidation.

Derivatives

During the years ended July 31, 2006 and 2005, the Company entered into forward sales contracts for the delivery of natural gas. During the year ended July 31, 2006, the Company determined and formally documented that such agreements qualify for normal purchase and sale accounting. During the year ended July 31, 2005, a determination as to whether such agreements qualify for normal purchase and sale accounting was not made and a liability to reflect the estimated fair value of such agreements of $150 was included in Accrued Expenses in the accompanying consolidated balance sheet.

Parts Inventory

Parts inventory is valued at the lower of average cost or market.

Properties

Proved

Oil and gas properties are accounted for using the successful efforts method. Under this method, all development and acquisition costs of proved developed properties are capitalized and amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves, respectively. Costs of drilling exploratory wells are initially capitalized, but charged to expense if and when a well is determined to be unsuccessful.

The Company evaluates the impairment of its proved oil and gas properties by field whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. Unamortized capital costs are reduced to fair value if the expected undiscounted future cash flows are less than the asset's net book value. Cash flows are determined based upon reserves using prices and costs consistent with those used for internal decision making. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with the New York Mercantile Exchange pricing and adjusted for estimated location and quality differentials, as well as other factors that management believes will impact realizable prices. Although prices used are likely to approximate market, they do not necessarily represent current market prices. Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects (by greater than ten percent) the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other properties are recognized currently. Expenditures for maintenance, repairs and minor renewals necessary to maintain properties in operating condition are expensed as incurred. Major replacements and renewals are capitalized. Estimated dismantlement and abandonment costs for oil and gas properties are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

Unproved

Unproved properties consist of costs incurred to acquire unproved leases (lease acquisition costs) as well as costs incurred to acquire unproved reserves. These costs are capitalized and amortized on a composite basis, based on past success, experience and average lease-term lives. Unamortized lease acquisition costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. The Company assesses unproved reserves for impairment annually by comparing book value to fair value, which is determined using discounted estimates of future cash flows.

Exploration

Costs of drilling exploratory wells are initially capitalized, but charged to expense if and when a well is determined to be unsuccessful. All other exploration costs are expensed as incurred. Determination is usually made within one year from the date drilling and other necessary activities have been completed. If a determination cannot be made after one year, all costs associated with the well are expensed.

Other

Other properties include pipelines, buildings, and other equipment. These items are recorded at cost and are depreciated using either the straight-line method based on expected lives of the individual assets or group of assets or the unit-of-production method over the remaining life of related proved reserves.

Revenue Recognition

Oil and gas revenues are recorded using the entitlement method. Under the entitlement method, revenue is recorded when title passes based on the Company’s net working interest. The Company records its entitled share of revenues based on entitled volumes and contracted sales prices (net of royalty). The sales price for oil and gas are adjusted for transportation cost and other related deductions. The transportation costs and other deductions are based on contractual or historical data and do not require significant judgment. Subsequently, these deductions and transportation costs are adjusted to reflect actual charges based on third party documents. These adjustments have historically been insignificant. Since there is a ready market for oil and gas, the Company sells the majority of its products soon after production at various locations at which time title and risk of loss pass to the buyer. As a result, the Company does not maintain product inventory.

Royalty Payable

It is the Company’s policy to calculate and pay royalties on natural gas and crude oil in accordance with the particular contractual provisions of the lease, license or concession agreements and the laws and regulations applicable to those agreements. Royalty liabilities are recorded in the period in which the natural gas or crude oil are produced and are included in Accrued Expenses on the Company’s Consolidated Balance Sheets. Oil and gas revenues are presented net of royalties.

Credit and Market Risks

The Company manages and controls market and counterparty credit risk through established formal internal control procedures which are reviewed on an ongoing basis. In the normal course of business, collateral is not required for financial instruments with credit risk. The Company uses the specific identification method of providing allowances for doubtful accounts.

Income Taxes

The Company files a consolidated federal income tax return with AMVEST Corporation. The Company's income taxes are computed on a separate return basis and are provided for based on the Company's taxable income in addition to a provision for deferred income taxes. Deferred income taxes are provided to reflect the tax consequences in future years of differences between the financial statement and tax basis of assets and liabilities. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil and gas reserves and related cash flow estimates used in impairment tests of other long-lived assets, estimates of future development, income taxes, dismantlement and abandonment costs, estimates relating to certain oil and gas revenues and expenses as well as estimates of expenses related to legal, environmental and other contingencies. Actual results could differ from those estimates.

Fair Value of Financial Instruments

The fair value of the Company's assets and liabilities that qualify as financial instruments, including accounts receivable and accounts payable, approximate carrying value given their short-term nature.

Recently Issued Accounting Pronouncements

In July 2006, the Financial Accounting Standards Board, or FASB, issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, or FIN 48. FIN 48 prescribes a two-step process for the financial statement recognition and measurement of tax positions taken or expected to be taken in a tax return. The first step involves evaluation of a tax position to determine whether it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position. The second step involves measuring the benefit to recognize in the financial statements for those tax positions that meet the more-likely-than-not recognition threshold. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 will become effective for the Company beginning August 1, 2007. The Company has not yet determined the effects that FIN 48 will have on its consolidated financial statements.

In September 2006, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 157, Fair Value Measurements (SFAS No. 157), which defines fair value, establishes a framework for measuring fair value and expands disclosures related to fair value measurements. SFAS No. 157 clarifies that fair value should be based on assumptions that market participants would use when pricing an asset or liability and establishes a fair value hierarchy of three levels that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data. SFAS No. 157 requires fair value measurements to be separately disclosed by level within the fair value hierarchy. The provisions of SFAS No. 157 will become effective for the Company beginning August 1, 2008. The Company has not yet determined the effects that SFAS No. 157 will have on its consolidated financial statements.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS No. 159). SFAS No. 159 provides an entity with the option, at specified election dates, to measure certain financial assets and liabilities and other items at fair value, with changes in fair value recognized in earnings as those changes occur. SFAS No. 159 also establishes presentation and disclosure requirements that include displaying the fair value of those assets and liabilities for which the entity elected the fair value option on the face of the balance sheet and providing management’s reasons for electing the fair value option for each eligible item. The provisions of SFAS No. 159 will become effective for the Company beginning August 1, 2008. The Company has not yet determined the effects that SFAS No. 159 will have on its consolidated financial statements.

2. Oil and Gas and Other Properties

Oil and gas properties and related equipment (successful efforts method) consists of the following:

	July 31	
	2006	2005
Property Costs		
Proved	$ 96,350	$ 75,724
Unproved	1,633	576
Total Property Costs	97,983	76,300
Land	407	372
Buildings	412	172
Equipment	1,337	1,214
Pipelines	4,151	2,168
Less: Accumulated depreciation, depletion and amortization	(18,965)	(11,767)
Oil and gas properties and equipment, net	$ 85,325	$ 68,459

3. Acquisitions and Divestitures

Acquisitions

In July 2006, the Company acquired certain oil and gas properties located in Oklahoma for $7,038 paid for in cash and the assumption of reclamation obligations. The fair value of assets acquired and liabilities assumed is as follows:

Property Costs	
Proved	$5,478
Unproved	1,325
Parts inventory	113
Land	20
Buildings	230
Equipment	6
Reclamation Obligations	(134)
	$7,038

Divestitures

In September 2005, the Company sold certain oil and gas properties located in Oklahoma that constituted a portion of the Company's amortization base for cash and the buyer's assumption of reclamation obligations totaling $6,200. The total consideration received for this sale was credited to the Company's oil and gas properties account used in calculating amortization expense. No gain was recognized on the sale.

4. Reclamation Obligations

The Company records the fair value of a liability for a reclamation obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the reclamation costs included in the carrying amount of the related asset is allocated to expense through depreciation or depletion of the asset. The majority of the Company's reclamation obligations relate to plugging and abandoning oil and gas wells and related equipment.

The following table reflects the changes in the Company's reclamation obligations:

Reclamation obligation at August 1, 2003	$ 472
Liabilities incurred	78
Liabilities settled	(21)
Current year accretion expense	29
Reclamation obligation at July 31, 2004	558
Liabilities incurred	126
Liabilities settled	(19)
Current year accretion expense	36
Reclamation obligation at July 31, 2005	701
Liabilities incurred	227
Liabilities settled	(207)
Current year accretion expense	42
Reclamation obligation at July 31, 2006	$ 763

5. Related Party Transactions

In the normal course of business, the Company enters into transactions with AMVEST and certain subsidiaries of AMVEST (collectively Affiliates).

Services Provided by Affiliates

Management services including accounting, marketing, human resources, and information technology are provided to the Company by Affiliates. Specific identifiable costs associated with these services are recorded as General and Administrative Expense in the accompanying Consolidated Statements of Income. Costs associated with these services that are not specifically identifiable are allocated to the Company based on its share of specifically identifiable costs. Management of the Company believes this method of allocation is reasonable. The total of such costs were $1,469, $1,295 and $1,225 for the years ended July 31, 2006, 2005 and 2004, respectively, and $1,247 and $1,103 for the nine month periods ended April 30, 2007 and 2006, respectively (unaudited).

The Company also pays a management fee to affiliates based on two percent of allocated management services cost that is included in General and Administrative Expense in the accompanying Consolidated Statements of Income. Management fees for the years ended July 31, 2006, 2005 and 2004 amounted to $29, $26 and $24, respectively.

Certain of the Company's employees began participating in a stock appreciation rights program sponsored by AMVEST during the year ended July 31, 2006. Costs associated with these employees and amounts allocable to the Company as part of the general overhead allocation discussed above amounted to $307 for the year ended July 31, 2006 and $460 and $188 for the nine month periods ended April 30, 2007 and 2006, respectively (unaudited), and are included in General and Administrative Expense in the accompanying Consolidated Statements of Income and as an increase in the Company's Additional Paid-In Capital. The stock appreciation rights were settled in connection with the transaction discussed in Note 10.

Substantially all of the Company’s employees participate in defined contribution plans sponsored by AMVEST. The Company’s contributions to these plans are based either on a percentage of salary or matching programs and amounted to $141, $117, and $85 for the years ended July 31, 2006, 2005 and 2004, respectively and $129 and $109 for the nine month periods ended April 30, 2007 and April 30, 2006, respectively (unaudited).

Services Provided to Affiliates

The Company provides land and inventory purchasing services to Affiliates. Reimbursements associated with these services amounted to $1, $3 and $11 for the years ended July 31, 2006, 2005 and 2004, respectively.

Due to Affiliates and Affiliate Cash Pool

Advances between the Company and AMVEST Corporation occur in the normal course of business. Such transactions are primarily related to funding activities for working capital and capital expansion programs for the Company’s drilling operations in Oklahoma. These amounts are included in Due to Affiliates in the accompanying Consolidated Balance Sheets and amounted to $29,096 and $23,991 at July 31, 2006 and 2005, respectively, and $24,682 at April 30, 2007 (unaudited). AMVEST Corporation also collects and disburses cash on behalf of the Company. Such transactions are included in Affiliate Cash Pool in the accompanying Consolidated Balance Sheets and amounted to $1,050 and $748 at July 31, 2006 and 2005, respectively, and $(6,715) at April 30, 2007 (unaudited).

Interest on the Due to Affiliates and Affiliate Cash Pool balances are based on applicable federal rates in effect each month and the weighted average rates were 4.25%, 2.83% and 1.44% for the years ended July 31, 2006, 2005 and 2004, respectively and 3.66% and 3.17% for the nine month periods ended April 30, 2007 and 2006, respectively (unaudited). Interest expense for the years ended July 31, 2006, 2005 and 2004 was $844, $573 and $148, respectively and $1,183 and $594 for the nine month periods ended April 30, 2007 and 2006, respectively (unaudited).

6. Income Taxes

Pretax Income and Income Tax Expense. The table below shows the Company's components of income tax expense for each of the three years ended July 31:

	2006	2005	2004
Income Tax Expense			
Current			
Federal	$1,148	$(2,565)	$ (205)
State	—	—	—
Total Current	1,148	(2,565)	(205)
Deferred			
Federal	4,458	5,402	1,508
State	754	8	—
Total Deferred	5,212	5,410	1,508
Total Income Tax Expense	$6,360	$ 2,845	$1,303

Effective Tax Rate Reconciliation. The Company's income taxes, included in net income, differ from the amount computed by applying the statutory federal income tax rate of 35 percent for the following reasons for each of the three years ended July 31:

	2006	2005	2004
Income tax at federal rate of 35%	$5,976	$3,288	$1,604
State income tax, net of federal benefit	754	209	108
Change in valuation allowance	—	(201)	(108)
Percentage depletion in excess of cost	(531)	(379)	(296)
Other, net	161	(72)	(5)
Total tax expense	$6,360	$2,845	$1,303
Effective tax rate	37.3%	30.3%	28.4%

Deferred Tax Assets and Liabilities. The following are the components of the Company's deferred tax assets and liabilities as of July 31:

	2006	2005
Deferred Tax Liabilities		
Fixed assets	$ 8,412	$ 5,653
Mineral reserves and intangible drilling costs	11,497	8,904
Total Deferred Tax Liabilities	$19,909	$14,557
Deferred Tax Assets		
Accrued derivative liability	$ —	$ 58
Accrued stock compensation	119	—
Oklahoma net operating loss carryforward	1,554	1,469
Other, net	3	9
Total Deferred Tax Assets	$ 1,676	$ 1,536

Net operating loss and tax carryovers. The Company has an Oklahoma state net operating loss carryforward of $38,880 which expires July 31, 2016 through July 31, 2027.

Valuation Allowances. Deferred tax assets are recorded on net operating losses and temporary differences in the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions during periods in which those temporary differences or net operating losses are deductible. In assessing the need for a valuation allowance on deferred tax assets, the Company considers whether it is more likely than not that some portion or all of them will not be realized. As part of the assessment, the Company considers future reversals of existing taxable temporary differences, primarily related to depreciation. The Company believes it is more likely than not that it will realize the benefit of the deferred tax assets at July 31, 2006 and 2005.

7. Commitments and Contingencies

Legal Proceedings

The Company and its subsidiaries can be named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of business. For each legal proceeding and other contingent matters, the Company evaluates the merits of the case, its exposure, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If the Company determines that an unfavorable outcome is probable and can be estimated, it establishes the necessary accruals. As of July 31, 2006 and 2005, the Company had no outstanding legal and other contingent matters.

Other Commercial Commitments

At July 31, 2006, the Company had various commercial commitments primarily related to commitments associated with drilling and gas gathering activities in Oklahoma. The Company is party to two two-year compressor operating lease contracts with annual payments amounting to $285 in 2007 and $261 in 2008.

In connection with the concession agreement with the Osage Nation, the Company is obligated to drill or earn 440 wells by December 31, 2008 to continue earning acreage and to perpetuate the concession. As of July 31, 2006, the Company has drilled or earned 320 wells toward this commitment. The agreement further provides three additional four-year phases commencing on January 1, 2009 and extending through December 31, 2020 in which the Company is obligated to drill 240 wells per phase to continue earning acreage and perpetuating the concession.

In connection with a gas purchase agreement, the Company is obligated to throughput commitments of 2.6 BCF of natural gas per year during the two year term, beginning January 1, 2006.

8. Cash Flow Information

During the year ended July 31, 2006, the Company paid a dividend of $4,000 that was settled through Due to Affiliates. In addition, the Company recognized $307 in expense for year ended July 31, 2006 and $460 and $188 for the nine month periods ended April 30, 2007 and 2006, respectively (unaudited), associated with AMVEST Corporation's stock appreciation rights program that was treated as an equity contribution.

Accounts payable includes amounts related to purchases of property and equipment in the amount of $1,393, $846, and $863 for the years ended July 31, 2006, 2005, and 2004, respectively and $1,297 and $999 for the nine month periods ended April 30, 2007 and 2006 (unaudited).

The Company incurred reclamation obligations of $227, $126 and $78 during the years ended July 31, 2006, 2005, and 2004, respectively, and $71 and $59 for the nine months ended April 30, 2007 and 2006, respectively (unaudited). Corresponding increases were recognized in oil and gas properties.

9. Other Information

Information About Major Customers. The Company has transactions with two major customers that amounted to approximately 94%, 82%, and 79%, of the Company's revenues for the years ended July 31, 2006, 2005 and 2004, respectively. Accounts receivables due from these customers were $4,495 and $2,905 at July 31, 2006 and 2005, respectively.

10. Subsequent Events

In June 2007, the Company's Due to Affiliates and Affiliate Cash Pool balances were settled with a corresponding increase in Additional Paid-In Capital.

In July 2007, the Company was purchased by Constellation Energy Partners LLC.

11. Supplemental Oil and Gas Disclosures – Unaudited

The Company is engaged in the exploration for, and the acquisition, development and production of oil and natural gas in the Cherokee Basin of Oklahoma.

Capitalized Costs. Capitalized costs relating to oil and gas producing activities and related accumulated depreciation, depletion and amortization were as follows at July 31:

	2006	2005	2004
Property Costs			
Proved	$ 96,350	$ 75,724	$50,921
Unproved	1,633	576	1,509
Total property costs	97,983	76,300	52,430
Other	6,307	3,926	2,843
Less: accumulated depreciation, depletion and amortization	(18,965)	(11,767)	(6,604)
TOTAL OIL AND GAS PROPERTIES AND EQUIPMENT, NET	$ 85,325	$ 68,459	$48,669

Total Costs Incurred. Costs incurred in oil and gas producing activities were as follows for each of the years ended July 31:

	2006	2005	2004
Property acquisition costs			
Proved	$ 4,460	$ 414	$ 97
Unproved	1,323	186	255
Total property acquisition costs	5,783	600	352
Exploration costs	459	243	255
Development costs	21,434	23,312	15,541
Other	2,826	1,367	1,072
TOTAL COST INCURRED	$30,502	$25,522	$17,220

Oil and Gas Reserves. Net quantities of proved developed and undeveloped reserves of natural gas and oil, and changes in these reserves at July 31, 2006, 2005, and 2004 are presented below. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate.

	Natural Gas (MMCF)	Oil (MMBBL)	Equivalents (MMCFE)
July 31, 2003	88,406	27	88,571
Extensions and discoveries			
Purchases of reserves in place			
Sales of reserves in place			
Revisions of previous estimates	(16,717)	95	(16,149)
Production	(3,025)	(19)	(3,140)
July 31, 2004	68,664	103	69,282
Extensions and discoveries	14,354	5	14,384
Purchases of reserves in place	1,831		1,831
Sales of reserves in place			
Revisions of previous estimates	713	149	1,609
Production	(4,027)	(31)	(4,212)
July 31, 2005	81,535	226	82,894
Extensions and discoveries	12,955		12,955
Purchases of reserves in place	3,665		3,665
Sales of reserves in place	(2,040)		(2,040)
Revisions of previous estimates	(18,688)	25	(18,535)
Production	(5,000)	(25)	(5,159)
July 31, 2006	72,427	226	73,780
Total developed reserves - 2004	40,127	103	40,745
Total developed reserves - 2005	47,378	226	48,737
Total developed reserves - 2006	46,539	226	47,892

There are numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and projecting the timing of development expenditures, including many factors beyond the Company's control. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretations and judgment. All estimates of proved reserves are determined according to the rules prescribed by the SEC. These rules indicate that the standard of "reasonable certainty" be applied to proved reserve estimates. This concept of reasonable certainty implies that as more technical data becomes available, a positive, or upward, revision is more likely than a negative, or downward, revision. Estimates are subject to revision based upon a number of factors, including reservoir performance, prices, economic conditions and government restrictions. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate. Reserve estimates are often different from the quantities of oil and gas that are ultimately recovered. The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from oil and gas properties the Company owns decline as reserves are depleted. Except to the extent the Company conducts successful exploration and development activities or acquires additional properties containing proved reserves, or both, the Company's proved reserves will decline as reserves are produced. There have been no major discoveries or other events, favorable or adverse, that may be considered to have caused a significant change in the estimated proved reserves since July 31, 2006.

Standardized Measure of Discounted Future Net Cash Flows. The standardized measure of discounted future net cash flows relating to proved oil and gas reserves at July 31:

	2006	2005	2004
Future cash inflows	$ 484,781	$ 597,542	$ 394,760
Future production costs	(185,115)	(193,694)	(132,294)
Future development costs	(40,742)	(45,375)	(38,845)
Future income tax expenses	(83,266)	(97,706)	(54,780)
Future net cash flows	175,658	260,767	168,841
10% annual discount for estimated timing of cash flows	(72,082)	(109,856)	(72,041)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 103,576	$ 150,911	$ 96,800

Changes in Standardized Measure of Discounted Future Net Cash Flows. The following are the principal sources of change in the standardized measure of discounted future net cash flows:

Standardized Measure as of July 31, 2003	$ 54,621
Sales and transfers of oil and gas produced, net of production costs	(9,611)
Net changes in prices and production costs	70,906
Extensions and discoveries, less related costs	—
Previously estimated development costs incurred during the period	17,670
Revisions of previous quantity estimates	(29,984)
Purchases and sales of mineral interests	—
Accretion of discount	7,256
Net change in income taxes	(14,058)
Other	—
Standardized Measure as of July 31, 2004	96,800
Sales and transfers of oil and gas produced, net of production costs	(19,815)
Net changes in prices and production costs	41,671
Extensions and discoveries, less related costs	21,297
Previously estimated development costs incurred during the period	10,668
Revisions of previous quantity estimates	11,586
Purchases and sales of mineral Interests	1,313
Accretion of discount	12,879
Net change in income taxes	(25,488)
Other	—
Standardized Measure as of July 31, 2005	150,911
Sales and transfers of oil and gas produced, net of production costs	(30,123)
Net changes in prices and production costs	(40,285)
Extensions and discoveries, less related costs	18,700
Previously estimated development costs incurred during the period	14,469
Revisions of previous quantity estimates	(39,990)
Purchases and sales of mineral Interests	2,189
Accretion of discount	20,839
Net change in income taxes	6,866
Other	—
Standardized Measure as of July 31, 2006	$103,576

Constellation Energy Partners LLC

UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL STATEMENTS

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Constellation Energy Partners LLC
Unaudited Pro Forma Condensed Combined Balance Sheet
At June 30, 2007
(in thousands)

	CEP Historical	Amvest Historical	Pro Forma Adjustments		CEP Pro Forma
Assets					
Current assets					
Cash and cash equivalents	$ 7,668	$ 3	$ 6,655	a,b,i	$ 14,326
Accounts receivable	9,717	4,381	(775)	a,i	13,323
Prepaid expenses	258	150	—		408
Risk management assets	5,922	—			5,922
Drilling fund		—	8,500	a	8,500
Other	2,033	6,039	(6,039)	i	2,033
Total current assets	25,598	10,573	8,341		44,512
Natural gas properties (See Note 2)					
Natural gas properties and related equipment					
Natural gas properties, equipment and facilities	306,448	130,451	96,520	a,i	533,419
Material and supplies	546	1,775	—		2,321
Less accumulated depreciation, depletion and amortization	(17,126)	(28,454)	28,454	i	(17,126)
Net natural gas properties	289,868	103,772	124,974		518,614
Other assets					
Loan Costs	1,229	—	350	a,c,i	1,579
Intangible contracts			5,000	a	5,000
Other Non-Current Assets	4,050	12	(12)	i	4,050
Risk management assets	1,839	—			1,839
Total assets	$322,584	$114,357	$ 138,653		$575,594
Liabilities and members' equity					
Liabilities					
Current liabilities					
Accounts payable	$ 2,364	$ 1,591	$ (210)	a,c,i	$ 3,745
Payable to affiliate	1,822	—			1,822
Accrued liabilities	3,847	1,137	(484)	a,i	4,500
Royalty payable	2,999	1,669	(389)	a,i	4,279
Deferred taxes	—	92	(92)	i	—
Environmental liability	717	—			717
Mark to market derivative liabilities	—	—			—
Total current liabilities	11,749	4,489	(1,175)		15,063
Other liabilities					
Asset retirement obligation	5,933	871			6,804
Deferred taxes	—	29,330	(29,330)	i	—
Mark to market derivative liabilities	1,873	—			1,873
Debt	82,500	—	42,500	b	125,000
Total other liabilities	90,306	30,201	13,170		133,677
Total liabilities	102,055	34,690	11,995		148,740
Class D Interests	7,667	—	—		7,667
Members' equity					
Members' equity	203,354	79,667	126,658	b,i	409,679
Accumulated other comprehensive income	9,508	—			9,508
Total members' equity	212,862	79,667	126,658		419,187
Total liabilities and members' equity	$322,584	$114,357	$ 138,653		$575,594

Constellation Energy Partners LLC
Unaudited Pro Forma Condensed Combined Statement of Operations
For the Year Ended December 31, 2006
(in thousands)

	CEP Historical	EQR and KPC Historical	Amvest Historical	Pro Forma Adjustments		CEP Pro Forma
Revenues						
Gas sales	$ 36,917	$ 18,772	$36,632	$ (1,625)	i	$ 90,696
Total Revenues	36,917	18,772	36,632	(1,625)		90,696
Expenses:						
Operating expenses:						
Lease operating expenses	7,234	8,806	6,871	(1,625)	i	21,286
Cost of sales			1,481			1,481
Production taxes	1,783	812	2,126			4,721
General and administrative	4,573		4,809	—	h	9,382
Depreciation, depletion and amortization	7,444	544	8,604	10,088	d	26,680
Accretion expense	141		42	216	e	399
Total operating expenses	21,175	10,162	23,933	8,679		63,949
Other expense/(income)						
Interest expense	221		1,178	6,365	f, g	7,764
Interest (income)	(468)					(468)
Other (income)	—		(12)			(12)
Total other expenses/(income)	(247)	—	1,166	6,365		7,284
						—
Total expenses	20,928	10,162	25,099	15,044		71,233
Income before taxes	$ 15,989	$ 8,610	$11,533	$ (16,669)		$ 19,463
Income tax provision	—		4,333	(4,333)	i	—
Net income (loss)	$ 15,989	$ 8,610	$ 7,200	$ (12,336)		$ 19,463
Other comprehensive income	13,113	—	—	—		13,113
Comprehensive income (loss)	$ 29,102	$ 8,610	$ 7,200	$ (12,336)		$ 32,576
Earnings per unit - Basic	$ 1.41					$ 0.98
Units outstanding - Basic	11,320,300			8,504,364	b	19,824,664
Earnings per unit - Diluted	$ 1.41					$ 0.98
Units outstanding - Diluted	11,320,300			8,504,364	b	19,824,664

Constellation Energy Partners LLC
Unaudited Pro Forma Condensed Combined Statement of Operations
For the Six Months Ended June 30, 2007
(in thousands)

	CEP Historical	EQR and KPC Historical	Amvest Historical	Pro Forma Adjustments		CEP Pro Forma
Revenues						
Gas sales	$ 26,497	$ 4,702	$20,073	$ (407)	i	$ 50,865
Loss from mark-to-market activities	(5,401)					(5,401)
Total Revenues	21,096	4,702	20,073	(407)		45,464
Expenses:						
Operating expenses:						
Lease operating expenses	4,745	1,966	3,992	(407)	i	10,296
Cost of sales	—		698			698
Production taxes	1,144	171	1,143			2,458
General and administrative	3,390		2,166	—	h	5,556
Loss on sale of asset	94					94
Depreciation, depletion and amortization	5,543	163	5,544	2,830	d, i	14,080
Accretion expense	113		21	54	e	188
Total operating expenses	15,029	2,300	13,564	2,477		33,370
Other expense/(income)						
Interest expense	1,825		683	1,946	f,g,i	4,454
Interest (income)	(135)					(135)
Other (income)	(70)		(37)			(107)
Total other expenses/(income)	1,620	—	646	1,946		4,212
Total expenses	16,649	2,300	14,210	4,423		37,582
Income before taxes	$ 4,447	$ 2,402	$ 5,863	$ (4,830)		$ 7,882
Income tax provision	—		1,857	(1,857)	i	—
Net income (loss)	$ 4,447	$ 2,402	$ 4,006	$ (2,973)		$ 7,882
Other comprehensive income	(3,605)	—	—	—		(3,605)
Comprehensive income (loss)	$ 842	$ 2,402	$ 4,006	$ (2,973)		$ 4,277
Earnings per unit - Basic	$ 0.36					$ 0.40
Units outstanding - Basic	12,201,279			7,623,385	b	19,824,664
Earnings per unit - Diluted	$ 0.36					$ 0.40
Units outstanding - Diluted	12,201,279			7,623,385	b	19,824,664
Distributions declared and paid per unit	0.6736					0.6736

Constellation Energy Partners LLC

NOTES TO UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

The unaudited pro forma condensed combined balance sheet as of June 30, 2007, is derived from:

- the historical consolidated financial statements of Constellation Energy Partners LLC ("CEP," or the "Company"); and
- the preliminary purchase price allocation of certain oil and natural gas properties and other related assets acquired in the purchase of Amvest Osage, Inc. (referred to as "Amvest").

The unaudited pro forma condensed combined statements of operations for the year ended December 31, 2006, and the six months ended June 30, 2007, are derived from:

- the historical consolidated financial statements of CEP;
- the historical consolidated financial statements of Amvest;
- the historical statements of direct revenues and direct operating expenses of EnergyQuest Resources, L.P. ("EQR"); and
- the historical financial statements of Kansas Processing EQR, LLC ("KPC").

The unaudited pro forma condensed combined balance sheet gives effect to the acquisition of Amvest and the related financing activities as if the transactions had occurred on June 30, 2007. The unaudited pro forma condensed combined statements of operation give effect to the acquisition of Amvest and of the EnergyQuest assets and the related financing activities as if the transactions had occurred on January 1, 2006.

The unaudited pro forma condensed combined financial statements reflect the following transactions:

- the acquisition of Amvest, EQR, and KPC;
- the equity issuance of additional Class B and the Class F units on July 25, 2007, used to finance the acquisition of Amvest; and
- an increase in debt in July 2007, used to finance the acquisition of Amvest and to fund certain investment capital expenditures in the Black Warrior Basin and Cherokee Basin.

The consolidated financial statements of Amvest included elsewhere in this Form 8-K/A have a fiscal year-end of July 31. The pro forma condensed combined financial statement information included in this Form 8-K/A is presented as of December 31, 2006 and June 30, 2007. In order to present a comparable fiscal period, we have utilized the financial statements of Amvest for the year ended July 31, 2006 and unaudited interim financial statement data.

The unaudited pro forma condensed combined balance sheet and statements of operations are presented for illustrative purposes only, and do not purport to be indicative of the financial position or results of operations that would actually have occurred if the transactions described had occurred as presented in such statements or that may be obtained in the future. In addition, future results may vary significantly from the results reflected in such statements due to factors described in "Risk Factors" included in our Quarterly Report on Form 10-Q for the six months ended June 30, 2007, in our Annual Report on Form 10-K for the year ended December 31, 2006 or elsewhere in the Company's reports and filings with the Securities and Exchange Commission ("SEC"). The unaudited pro forma condensed combined balance sheet and statements of operations should be read in conjunction with our historical consolidated financial statements and the notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2006 and our Quarterly Report on Form 10-Q for the six months ended June 30, 2007.

The pro forma statements should also be read in conjunction with the consolidated financial statements for Amvest included elsewhere in this Form 8-K/A and with the statements of direct revenues and direct operating expenses for EQR and the notes thereto and the consolidated financial statements of KPC and the notes thereto included in a Form 8-K/A filing with the SEC dated July 5, 2007.

2. ACQUISITION AND PRELIMINARY PURCHASE PRICE ALLOCATION

The acquisition of Amvest was completed on July 25, 2007. The Company acquired certain oil and natural gas properties from Amvest for approximately $240.0 million, subject to purchase price adjustments.

The acquisition included a 13 year exclusive concession from the Osage Nation for coalbed methane and shale rights on approximately 560,000 net acres in Osage County, Oklahoma, with potential for up to 100,000 additional acres, and approximately 370 producing wells with current net production of 16 MMcfe per day. Also included were support equipment and facilities, including certain pipeline gathering systems.

The total consideration was $241.9 million which consisted of cash of $241.0 million and estimated transaction costs of $0.9 million. An amount of $8.5 million was included in a drilling escrow fund that was returned to the Company for use for drilling programs on proved undeveloped locations after the close of transaction. The purchase price allocation of the total consideration (after the return of the drilling fund) of $233.4 million is as follows:

Natural Gas and Oil Properties	$ 181.3 million
Unproved Properties	38.4 million
Pipelines	5.0 million
Other PP&E	1.4 million
Intangible Third Party Gas Contracts	5.0 million
Net Working Capital	2.3 million
Total	$ 233.4 million

The preliminary purchase price allocation used for the purpose of this pro forma financial information is based on preliminary appraisals, evaluations of proved oil and natural gas reserves, discounted cash flows, quoted market prices, other estimates by management, and a preliminary third party valuation report. The purchase price allocation related to the acquisition of Amvest is preliminary and subject to change, pending finalization of the valuation of the assets and liabilities acquired.

3. PRO FORMA ADJUSTMENTS

The unaudited pro forma condensed combined financial statements have been adjusted to reflect the following:

a. the purchase of Amvest as detailed in Note 2

b. the issuance and sale of 3,371,219 Class F Units and 2,664,998 Common Units for approximately $206.3 million ($210.0 million less $3.675 million in estimated expenses) and borrowings of $42.5 million under the reserve-based credit facility to fund the remaining balance of the purchase price and certain investment capital expenditures in the Black Warrior Basin and the Cherokee Basin

c. the debt issuance costs of approximately $0.35 million related to the borrowings under the reserve-based credit facility to fund the remaining purchase price of Amvest

d. recording incremental depreciation, depletion and amortization expense related to the acquired Amvest, EQR, and KPC assets based on the relative fair value allocation of the purchase price to the acquired assets

e. recording incremental accretion expense related to the assumed asset retirement obligations of EQR

f. recording incremental interest expense at 7.11% associated with the increase in long-term debt of approximately $42.5 million incurred to fund the balance of the purchase price of Amvest, as well as to fund planned capital expenditures on these properties and recording incremental interest expense at 7.235% associated with the increase in long-term debt of approximately $60.5 million incurred to fund the balance of the purchase price of EQR, the escrow deposit and certain investment capital expenditures in the Black Warrior Basin

A 0.125% increase or decrease in this rate results in a $0.13 million change in interest expense associated with these increases in outstanding debt.

g. recording incremental amortization of additional debt issuance costs associated with the increase in the reserve-based credit facility

h. no incremental pro forma adjustments for general and administrative expenses have been reflected for any costs associated with the Transition Services Agreement, pursuant to which EQR will operate the EnergyQuest assets and conduct a specified drilling program on CEP's behalf. The Transition Services Agreement provides for a reimbursement of EQR's actual costs plus a 10% premium for any general and administrative services that CEP specifically requests. This amount may not be indicative of any actual future general and administrative costs incurred by CEP. Under this agreement, CEP estimates that the monthly requested general and administrative services will be approximately $140,000 per month.

i. To eliminate intercompany activities between EQR and KPC, to eliminate historical balances from Amvest not acquired in the transaction, to eliminate historical interest expense on historical affiliate balances, and to eliminate historical income tax-related balances as CEP is not a taxpayer.

4. DEBT

In July 2007, the Company borrowed $42.5 million under the reserve-based credit facility to fund the purchase price of the acquisition of Amvest, as well as to fund a portion of planned capital expenditures on these properties. On July 6, 2007, the borrowing base of the reserve-based credit facility was increased to $135.0 million, and then to $180.0 million on July 26, 2007.

In July 2007, the amount guaranteed under a credit support fee agreement with Constellation Energy ("CEG"), under which CEG will guarantee credit support for the Company's financial derivatives, was increased to $15.0 million. This guarantee and another guarantee for $25.0 million were released effective July 6, 2007, when the borrowing base under the Company's reserve-based credit facility was increased to $135.0 million. On July 13, 2007, the Company entered into a credit support fee agreement with CEG under which CEG will guarantee credit support up to $15.0 million for financial derivatives that the Company entered into in relation to the Amvest Acquisition. This guarantee was released on July 26, 2007, when the borrowing base under the Company's reserve-based credit facility was increased to $180.0 million. Debt issuance costs related to these transactions were approximately $0.5 million which are being amortized over the life of the facility. The reserve-based credit facility will mature in October 2010.

5. EQUITY ISSUANCE

On July 16, 2007, the Company entered into a Class F Unit and Common Unit Purchase Agreement (the "Unit Purchase Agreement") with certain unaffiliated third-party investors (the "Purchasers") to sell 3,371,219 Class F Units representing limited liability company interests (the "Class F Units") and 2,664,998 common units representing Class B limited liability company interests (the "New Common Units") in a private placement (the "Private Placement") for an aggregate purchase price of approximately $210 million. The Company issued and sold 3,371,219 Class F Units and 2,664,998 New Common Units to the Purchasers pursuant to the Unit Purchase Agreement on July 25, 2007. The Company used the proceeds from the Private Placement, together with funds available under the Company's revolving credit facility, to fund the purchase price of the acquisition of Amvest. At the issuance of the Class F and New Common Units, additional Class A units were issued such that the total outstanding amount remained at 2% of all outstanding units. Estimated offering expenses were $3.675 million.

In connection with the Unit Purchase Agreement, the Company entered into a registration rights agreement (the "Registration Rights Agreement") with the Purchasers dated July 25, 2007. Pursuant to the Registration Rights Agreement, the Company is required to prepare and file a registration statement within 90 days of the closing of the Private Placement (the "Closing Date"), and use its commercially reasonable efforts to cause the registration statement to become effective no later than 135 days following the Closing Date. In addition, the Registration Rights Agreement gives the Purchasers piggyback registration rights under certain circumstances. These registration rights are transferable to affiliates and, in certain circumstances, to third parties.

If the registration statement is not declared effective within 165 days after the Closing Date, then the Company must pay each Purchaser, as liquidated damages, 0.25% of the sum of the product of $34.43 times the number of Class F Units purchased by such Purchaser plus the product of $35.25 times the number of New Common Units purchased by such Purchaser (the "Liquidated Damages Multiplier") per 30-day period for the first 90 days following the 165th day after the Closing Date, increasing by an additional 0.25% of the Liquidated Damages Multiplier per 30-day period for each subsequent 30 days, up to a maximum of 1.00% of the Liquidated Damages Multiplier per 30-day period. There is no limitation on the aggregate amount of the liquidated damages the Company must pay each Purchaser.

6. SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (Unaudited)

The following table sets forth certain unaudited pro forma information concerning the Company's proved oil and natural gas reserves for the year ended December 31, 2006, giving effect to the transaction relating to the acquisition of Amvest and of the EnergyQuest assets as if they had occurred on January 1, 2006. The information excludes reserves related to royalty and net profit interests. The Company's estimate of proved reserves is based on the quantities of natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. There are numerous uncertainties inherent in estimating the quantities of proved reserves and projecting future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact.

Natural Gas Reserves—MMCF

Year-Ended December 31, 2006

	CEP Historical	EQR Historical	Amvest Historical	CEP Pro Forma
Beginning Balance	112,025	39,822	76,733	228,580
Extensions and discoveries	—	5,334	25,678	31,012
Purchases of reserves in place	—	—	3,665	3,665
Sales of reserves in place	—	—	—	—
Revisions of previous estimates	12,952	(1,668)	(30,651)	(19,367)
Production	(4,641)	(2,279)	(5,367)	(12,287)
End of year	120,336	41,209	70,058	231,603
Total developed reserves	97,387	23,479	44,170	165,036

Oil, Condensate, and Liquids—MBBLS

Year-Ended December 31, 2006

	CEP Historical	EQR Historical	Amvest Historical	CEP Pro Forma
Beginning Balance	—	8	209	217
Extensions and discoveries	—	—	—	—
Purchases of reserves in place	—	—	—	—
Sales of reserves in place	—	—	—	—
Revisions of previous estimates	—	8	31	39
Production	—	(2)	(26)	(28)
End of year	—	14	214	228
Total developed reserves	—	14	214	228

Natural Gas Reserves—MMCFE

Year-Ended December 31, 2006

	CEP Historical	EQR Historical	Amvest Historical	CEP Pro Forma
Beginning Balance	112,025	39,873	77,990	229,888
Extensions and discoveries	—	5,334	25,678	31,012
Purchases of reserves in place	—	—	3,665	3,665
Sales of reserves in place	—	—	—	—
Revisions of previous estimates	12,952	(1,621)	(30,467)	(19,136)
Production	(4,641)	(2,293)	(5,526)	(12,460)
End of year	120,336	41,293	71,340	232,969
Total developed reserves	97,387	23,563	45,452	166,402

The following table sets forth certain unaudited pro forma information for the Company's standardized measure of discounted cash flows relating to proved oil and natural gas reserves as of December 31, 2006, giving effect to the transaction relating to the acquisition of Amvest and of the EnergyQuest assets as if they had occurred on January 1, 2006. Certain information concerning the assumptions used in computing the valuation of proved reserves and their inherent limitations are discussed below.

Future cash inflows are calculated by applying year-end prices of natural gas, relating to the proved reserves, to the year-end quantities of those reserves. Future cash inflows exclude the impact of the Company's hedging program and mark-to-market derivatives. Future development and production costs represent the estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. In addition, asset retirement obligations are included within future production and development costs. There are no future income tax expenses because the Company is a non-taxable entity.

The assumptions used to compute estimated future cash inflows do not necessarily reflect expectations of actual revenues or costs or their present value. In addition, variations from expected production rates could result directly or indirectly from factors outside of the Company's control, such as unexpected delays in development, changes in prices or regulatory or environmental policies. The reserve valuation further assumes that all reserves will be disposed of by production; however, if reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized.

Standardized Measure

Year-Ended December 31, 2006

	CEP Historical	EQ Historical	Amvest Historical	CEP Pro Forma
Future cash inflows	677,866	216,410	412,325	1,306,601
Future production costs	(257,502)	(79,642)	(178,655)	(515,799)
Future estimated development costs	(64,673)	(24,629)	(40,742)	(130,044)
Future net cash inflows	355,691	112,139	192,928	660,758
10% annual discount for estimated timing of cash flows	(235,504)	(52,037)	(76,205)	(363,746)
Standardized measure of discounted estimated future net cash flows	120,187	60,102	116,723	297,012

The following table sets forth certain unaudited pro forma information for the principal sources of changes in discounted future net cash flows from the Company's proved oil and natural gas reserves for the year ended December 31, 2006, giving effect to the transaction relating to the acquisition of Amvest and of the EnergyQuest assets as if they had occurred on January 1, 2006.

Changes in Standardized Measure

Year-Ended December 31, 2006

	CEP Historical	EQ Historical	Amvest Historical	CEP Pro Forma
Beginning of the period	295,435	109,627	297,930	702,992
Sales and transfer of natural gas and oil, net of production costs	(40,064)	(11,996)	(46,925)	(98,985)
Net changes in prices and production costs related to future production	(193,499)	(52,950)	(174,114)	(420,563)
Development costs incurred during the period	12,292	1,457	14,469	28,218
Changes in extensions and discoveries	—	9,239	27,838	37,077
Revisions of previous quantity estimates	18,435	(3,013)	(45,702)	(30,280)
Purchases of reserves in place	—	—	13,435	13,435
Accretion discount	29,624	10,963	29,792	70,379
Other	(2,036)	(3,225)	—	(5,261)
Standardized measure of discounted estimated future net cash flows	120,187	60,102	116,723	297,012

7. SUBSEQUENT EVENT

Newfield Acquisition Announcement

In August 2007, the Company announced that it had entered into a definitive purchase agreement to acquire additional coalbed methane properties in the Cherokee Basin of Oklahoma (the "Newfield Assets") for approximately $128 million, subject to purchase price adjustments. The Company executed a unit purchase agreement with third party investors to sell 2,470,592 common units at a price of $42.50 per unit in a private placement for an aggregate purchase price of approximately $105 million. The Company has agreed to file a registration statement with the SEC registering for resale the common units within 90 days after the closing of the private placement. The Company believes that the proceeds from this equity private placement, together with funds available under its existing credit facility, will fully fund the purchase price of the acquisition. The Company anticipates that the private placement will close simultaneously with the acquisition of the assets in September 2007. The Company borrowed $13.0 million under its reserve-based credit facility to fund an acquisition deposit escrow account. The Company also entered into derivative transactions to hedge the future expected production associated with this acquisition.

Debt

In August 2007, the Company borrowed an additional $13.0 million to fund an acquisition deposit escrow account for the purchase of the Newfield Assets.

In August 2007, the amount guaranteed under the credit support fee agreement with CEG, under which CEG will guarantee credit support for the Company's financial derivatives, was increased to $10.0 million. The guarantee is for financial derivatives that the Company entered into in anticipation of the acquisition of the Newfield Assets.