EASTERN AMERICAN NATURAL GAS TRUST
Form 10-Q
November 09, 2005

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

ý	**QUARTERLY REPORT UNDER SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**
	For the quarterly period ended September 30, 2005
	OR
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number 1-11748

EASTERN AMERICAN NATURAL GAS TRUST

(Exact name of registrant as specified in its charter)

Delaware	**36-7034603**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

JPMorgan Chase Bank, N.A., Trustee

Institutional Trust Services

700 Lavaca, 2nd Floor

Austin, Texas

(Address of principal executive offices)

78701

(Zip Code)

(800) 852-1422

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes o No ý

(1) The Registrant inadvertently did not file a report on Form 8-K for its 2004 third quarter press release announcing quarterly distributable income and distribution amounts.

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).

Yes ý No o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No ý

As of November 4, 2005, 5,900,000 Units of Beneficial Interest in Eastern American Natural Gas Trust were outstanding.

PART I FINANCIAL INFORMATION

ITEM 1. Financial Statements

EASTERN AMERICAN NATURAL GAS TRUST

STATEMENTS OF DISTRIBUTABLE INCOME

(Unaudited)

	Nine Months Ended September 30 2005	Nine Months Ended September 30 2004	Three Months Ended September 30 2005	Three Months Ended September 30 2004
Royalty Income	$ 12,221,141	$ 10,024,331	$ 4,659,185	$ 3,452,442
Operating Expenses				
Taxes on production and property	839,691	683,658	320,484	232,004
Operating cost charges	400,761	389,950	133,587	129,280
Total Operating Expenses	1,240,452	1,073,608	454,071	361,284
Net Proceeds to the Trust	10,980,689	8,950,723	4,205,114	3,091,158
General and Administrative Expenses	(1,017,252)	(651,903)	(405,340)	(242,168)
Interest Income	500	838		405
Cash Proceeds on Sale of Net Profits Interests		80,205		
Distributable Income	9,963,937	8,379,863	3,799,774	2,849,395
Cash Reserve	(185,000)	(100,000)		
Distribution Amount	$ 9,778,937	$ 8,279,863	$ 3,799,774	$ 2,849,395
Distributable Income Per Unit (5,900,000 units authorized and outstanding)	$ 1.6888	$ 1.4203	$ 0.6440	$ 0.4829
Distribution Amount Per Unit (5,900,000 units authorized and outstanding)	$ 1.6574	$ 1.4034	$ 0.6440	$ 0.4829

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

PART I FINANCIAL INFORMATION

EASTERN AMERICAN NATURAL GAS TRUST

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	September 30, 2005 (Unaudited)	December 31, 2004
Assets:		
Cash	$ 259,221	$ 185,752
Net Proceeds Receivable	4,205,114	3,989,827
Net Profits Interests in Gas Properties	93,162,180	93,162,180
Accumulated Amortization	(64,861,764)	(62,337,672)
Total Assets	$ 32,764,751	$ 35,000,087
Liabilities and Trust Corpus:		
Trust General and Administrative		
Expenses Payable	$ 164,561	$ 220,596
Distributions Payable	3,799,774	3,639,983
Trust Corpus (5,900,000 Trust Units authorized and outstanding)	28,800,416	31,139,508
Total Liabilities and Trust Corpus	$ 32,764,751	$ 35,000,087

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

EASTERN AMERICAN NATURAL GAS TRUST

STATEMENTS OF CHANGES IN TRUST CORPUS

(Unaudited)

	Nine Months Ended September 30, 2005	Nine Months Ended September 30 2004
Trust Corpus, Beginning of Period	$ 31,139,508	$ 34,857,666
Distributable Income	9,963,937	8,379,863
Distributions Payable to Unitholders	(9,778,937)	(8,279,863)
Amortization of Net Profits Interests in Gas Properties	(2,524,092)	(2,785,090)
Trust Corpus, End of Period	$ 28,800,416	$ 32,172,576

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

4

EASTERN AMERICAN NATURAL GAS TRUST

NOTES TO UNAUDITED CONDENSED FINANCIAL STATEMENTS

NOTE 1. Organization of the Trust

The Eastern American Natural Gas Trust (the Trust) was formed under the Delaware Business Trust Act pursuant to a Trust Agreement (the Trust Agreement) among Eastern American Energy Corporation (Eastern American), as grantor, Bank of Montreal Trust Company, as trustee, and Wilmington Trust Company, as Delaware Trustee (the Delaware Trustee). Effective May 8, 2000, The Bank of New York acquired the corporate trust business of the then current Trustee and served as Trustee through December 31, 2004. On November 20, 2004, the holders of a majority of the Trust Units voting at a special meeting approved the resignation of The Bank of New York, as trustee and depository of the Trust, and the appointment of JPMorgan Chase Bank, N.A. as successor trustee (Trustee) of the Trust. The appointment of JPMorgan Chase Bank, N.A., as successor trustee, became effective as of January 1, 2005. Effective January 1, 2005, the transfer agent for the Trust is Bondholder Communications.

The Trust was formed to acquire and hold net profits interests (the Net Profits Interests) created from the working interests owned by Eastern American in 650 producing gas wells and 65 proved development well locations (the Development Wells) in West Virginia and Pennsylvania (the Underlying Properties).

On March 15, 1993, 5,900,000 Depositary Units were issued in a public offering at an initial public offering price of $20.50 per Depositary Unit. Each Depositary Unit consists of beneficial ownership of one unit of beneficial interest (Trust Unit) in the Trust and a $20 face amount beneficial ownership interest in a $1,000 face amount zero coupon United States Treasury Obligation (Treasury Obligation) maturing on May 15, 2013. The financial statements of the Trust to which these notes relate do not include information concerning the Treasury Obligations, the beneficial interest in which is held for the Unitholders by the Depositary.

The Net Profits Interests are passive in nature, and neither the Trustee nor the Delaware Trustee has management control or authority over, nor any responsibility relating to, the operation of the properties subject to the Net Profits Interests. The Trust Agreement provides, among other things, that the Trust shall not engage in any business or commercial activity or acquire any asset other than the Net Profits Interests initially conveyed to the Trust; the Trustee may establish a reserve for payment of any liability that is contingent, uncertain in amount or is not currently due and payable; the Trustee is authorized to borrow funds required to pay liabilities of the Trust, provided that such borrowings are repaid in full prior to further distributions to Unitholders; and the Trustee will make quarterly cash distributions to Unitholders from funds of the Trust.

After the Trust was formed, 59 of the 65 Development Wells were drilled and completed. The remaining six Development Wells were not drilled. Clear title to two of the Development Wells could not be established, and they were excluded from the Trust in accordance with the conveyance transferring them to the Trust. Eastern American asserted the remaining four undrilled Development Wells, if drilled, would be too close to then existing wells on the property or an adjoining property, and thereafter settled its dispute with the Trust about drilling those four Development Wells by agreeing instead to pay the Trust annually for the annual volume of gas projected to be produced from those Development Wells as if they had been drilled.

The Net Profits Interests initially consisted of a royalty interest (Royalty NPI) in 322 wells and a term interest (Term NPI) in the remaining wells and locations. As of September 30, 2005, the Trust held Net Profits Interests in 671 wells, consisting of Royalty NPI in 317 wells and Term NPI in the remaining wells. The Term NPI expire by their terms on May 15, 2013, or such earlier time as 41,683 MMcf of gas has been produced that is attributable to Eastern American s net revenue interest in the properties burdened by the Term NPI. As of December 31, 2004, based on the Independent Petroleum Engineer s Report, 20,706 MMcf of the maximum 41,683 MMcf has been produced.

Between May 15, 2012 and May 15, 2013 (the Liquidation Date), the Trustee is required to sell all the Royalty NPI and liquidate the Trust. Under the Trust Agreement, Eastern American has the right of first refusal to purchase any of the Royalty NPI the Trustee is required to sell after the Liquidation Date. If it exercises this right, Eastern American must pay the appraised Fair Value (as defined in the Trust Agreement) of the Royalty NPI, or the relevant third party offer price if a third party has offered to purchase the Royalty NPI. Unitholders of record on the relevant record dates will receive the net proceeds from selling the Royalty NPI in accordance with the Trust Agreement, and also will receive their respective share of the matured face amount of the Treasury Obligations held by the Depositary.

NOTE 2. Basis of Presentation

The preparation of financial statements requires estimates and assumptions that affect 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 revenue and expenses during the reporting period. Without limiting the foregoing statement, the information furnished is based upon certain estimates of production for the periods presented and is therefore subject to adjustment in future periods to reflect actual production for the periods presented. The information furnished reflects all adjustments which are, in the opinion of the Trustee, necessary for a fair presentation of the results for the interim periods presented. The accompanying financial statements are unaudited interim financial statements, and should be read in conjunction with the audited financial statements and notes thereto included in the Trust s Annual Report on Form 10-K for the year ended December 31, 2004, as amended.

NOTE 3. Trust Accounting Policies

The Trust serves as a pass-through entity, with items of depletion, interest income and expense, and income tax attributes being based upon the status and elections of Unitholders. Thus, the Statements of Distributable Income show Distributable Income, defined as Trust income available for distribution to Unitholders, subject to Cash Reserves, if any, described in Part I, Item 2 before application of those Unitholders additional expenses, if any, for depletion, interest expense, and income taxes. The Trust uses the accrual basis to recognize revenue, with Royalty Income recognized as gas reserves are extracted from properties and sold. Expenses are also presented on an accrual basis. Actual cash receipts will vary from the accrual of revenues due to, among other reasons, the payment provisions of the gas purchase contract between the Trust and Eastern Marketing Corporation (a subsidiary of Eastern American), which requires payment with respect to gas production for a calendar quarter to be made to the Trust on or before the tenth day of the third month following such quarter.

The Net Profits Interests are assessed annually to determine whether their net capitalized cost is impaired. The Trust will determine if a writedown is necessary to its investment in the Net Profits Interests in gas properties to the extent that total capitalized costs, less accumulated amortization, exceed undiscounted future net revenues attributable to proved gas reserves of the Underlying Properties. The Trust will then provide a writedown to the extent that the net capitalized costs exceed the discounted future net revenues attributable to proved gas reserves of the Underlying Properties. Any such writedown would not reduce distributable income, although it would reduce Trust Corpus.

Amortization of the Net Profits Interests in Gas Properties is calculated on a units-of-production basis, whereby the Trust s cost basis in the properties is divided by total Trust proved reserves to derive an amortization rate per reserve unit. Such amortization does not reduce distributable income, rather it is charged directly to Trust Corpus.

The financial statements of the Trust differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America due to the following: (i) certain cash reserves may be established for contingencies which were not accrued in the financial statements; (ii) amortization of the Net Profits Interests in gas properties is charged directly to Trust Corpus; and (iii) the sale of the Net Profits Interests is reflected in the Statements of Distributable Income as cash proceeds to the Trust.

NOTE 4. Income Taxes

The Trust is a grantor trust and is not required to pay federal or state income taxes. Accordingly, no provision for federal or state income taxes has been made. All income is taxed to the Unitholders of the Trust.

ITEM 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

Cautionary Statement

This Form 10-Q includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included in this Form 10-Q, including without limitation the statements under Management s Discussion and Analysis of Financial Condition and Results of Operations are forward-looking statements. Although Eastern American has advised the Trustee that its believes that the expectations reflected in the forward-looking statements contained herein are reasonable, no assurance can be given that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from expectations (Cautionary Statements) are disclosed in this Form 10-Q and in the Trust s Annual Report on Form 10-K for the year ended December 31, 2004, as amended, and include the fact that none of the Trust, the Trustee or Eastern American is able to predict future changes in gas prices, gas production levels, economic activity, legislation or regulation, or certain changes in expenses of the Trust. All subsequent written and oral forward-looking statements attributable to the Trust or persons acting on its behalf are expressly qualified in their entirety by the Cautionary Statements. The Trust, the Trustee and Eastern American disclaim any obligation to update any forward looking statements.

General

The Trust does not conduct any operations or activities. The Trust s purpose is, in general, to hold the Net Profits Interests, to distribute the cash proceeds to Unitholders which the Trust receives in respect of the Net Profits Interests (net of Trust expenses), and to perform certain administrative functions in respect of the Net Profits Interests and the Depositary Units. Accordingly, the Trust derives substantially all of its income and cash flows from the Net Profits Interests. The Trust has no source of liquidity or capital resources other than the cash flows from the Net Profits Interests.

The Net Profits Interests were created pursuant to conveyances (the Conveyances) from Eastern American to the Trust. In connection therewith, Eastern American assigned its rights under a gas purchase contract (the Gas Purchase Contract), which obligates Eastern Marketing Corporation, a subsidiary of Eastern American, to purchase all of the natural gas produced from the Underlying Properties that is attributable to the Net Profits Interests.

The Conveyances and the Gas Purchase Contract entitle the Trust to receive an amount of cash for each calendar quarter equal to the Net Proceeds for such quarter. Net Proceeds for any calendar quarter generally means an amount of cash equal to (a) 90% of a volume of gas equal to (i) the volume of gas produced during such quarter attributable to the Underlying Properties less (ii) a volume of gas equal to Chargeable Costs for such quarter, multiplied by (b) the applicable price for such quarter under the Gas Purchase Contract. Chargeable Costs is that volume of gas which equates in value, determined by reference to the relevant sales price under the Gas Purchase Contract or the Conveyances, as applicable, to the sum of the Operating Cost Charge , Capital Costs and Taxes .

The Operating Cost Charge for 2005 is based on an annual rate of $535,224, and for 2004 was an annual rate of $521,340. As provided in the Conveyances, the Operating Cost Charge will fluctuate based

on the lesser of (A) five percent (5%) or (B) a percentage, not less than zero percent (0%), equal to the percentage increase, if any, in the average weekly earnings of Crude Petroleum and Gas Production Workers for the last calendar year, as shown by the index of average weekly earnings of Crude Petroleum and Gas Production Workers, as published by the United States Department of Labor, Bureau of Labor Statistics, based on December-to-December comparison.

During 2003, the United States Department of Labor, Bureau of Labor Statistics converted all of its industry-based statistics to a different reporting system that was developed in cooperation with the United States   North American Free Trade Agreement Partners, Canada and Mexico, in an effort to standardize and modernize reporting codes. As a result of this conversion, the Crude Petroleum and Gas Production Workers index is no longer available for use in the annual calculation of overhead adjustment called for in the various Council of Petroleum Accountants Societies (COPAS) model forms after March 2003.

Research by COPAS covering the past ten years indicated that by blending the Oil and Gas Extraction Index with the Professional and Technical Services Index, the results approximate the data from the old Crude Petroleum and Natural Gas Workers Index. Accordingly, COPAS has calculated the percentage change in the simple average of the Oil and Extraction Index and the Professional and Technical Services Index, commencing in April 2004. This   Overhead Adjustment Index   has been provided as a guidance to the industry as a replacement index for use in calculating the overhead adjustment. The adjustment for the effective time period is 3.5%. Since the Conveyance Documents do not specifically provide for a replacement index if the Crude Petroleum and Gas Production Workers Index is no longer published, Eastern American believes, and advised the Trustee, that the   Overhead Adjustment Index   as calculated by COPAS is a reasonable index to utilize since the industry is generally adopting the same as a replacement. Eastern American, with the concurrence of the Trustee, will utilize this   Overhead Adjustment Index   to adjust the   Operating Cost Charge   so long as such index is published by COPAS.

The Operating Cost Charge will be reduced for each well that is sold (free of the Net Profits Interests) or plugged and abandoned. Capital Costs are defined as Eastern American s working interest share of capital costs for operations on the Underlying Properties having a useful life of at least three years, and excluding any capital costs incurred in drilling the Development Wells. Taxes refer to ad valorem taxes, production and severance taxes, and other taxes imposed on Eastern American s or the Trust s interests in the Underlying Properties, or production therefrom.

Pursuant to the Gas Purchase Contract, Eastern Marketing is obligated to purchase such gas production at a purchase price per Mcf equal to the Index Price. The Index Price for any quarter is determined solely by reference to the Variable Price component. The Variable Price for any quarter is equal to the Henry Hub Average Spot Price (as defined) per MMBtu plus $0.30 per MMBtu, multiplied by 110% to effect a fixed adjustment for Btu content. The Henry Hub Average Spot Price is defined as the price per MMBtu determined for any calendar quarter equal to the price obtained with respect to each of the three months in such quarter, in the manner specified below, and then taking the average of the prices determined for each of such three months. The price determined for any month of such quarter is equal to the average of (i) the final settlement price per MMBtu for Henry Hub Gas Futures Contracts (as defined), as reported in *The Wall Street Journal*, for such contracts which expired in each of the five months prior to such month; (ii) the final settlement price per MMBtu for Henry Hub Gas Futures Contracts, as reported in *The Wall Street Journal*, for such contracts which expire during such month; and (iii) the closing settlement price per MMBtu of Henry Hub Gas Futures Contracts determined as of the contract settlement date for such month, as reported in *The Wall Street Journal*, for such contracts which expire in each of the six months following such month. A Henry Hub Gas Futures Contract is defined as a gas futures contract for gas to be delivered to the Henry Hub that is traded on the New York Mercantile Exchange.

Accordingly, the Index Price payable to the Trust for production may be higher or lower based on the fluctuations in natural gas futures prices during the relevant calculation period. The price payable to the Trust will have a direct impact, positively or negatively, on the quarterly distributions payable by the Trust to its unit holders.

Eastern American had a disagreement with the Trust over Eastern American s obligation to drill certain Development Wells that were closely offset by third parties. The Trust agreed that in lieu of drilling these closely offset Development Wells, Eastern American could provide the Trust, on an annual basis commencing on April 1, 1997, and over the remaining life of the Trust, a volume of gas which is equal to the projected volumes of the wells as if they had been drilled. These volumes have been estimated by Ryder Scott Company, independent petroleum engineers. During the quarter ended September 30, 2005, an additional volume of 4,123 Mcf was delivered to the Trust, as compared to 4,457 Mcf for the quarter ended September 30, 2004. These additional volumes fulfill Eastern American s obligation to provide volumes for Development Wells that had been closely offset by third parties.

Eastern American has fulfilled its obligation with respect to the drilling of the Development Wells. Since the inception of the Trust, Eastern has drilled a total of 59 Development Wells, which are online and producing. (See the Trust s Annual Report on Form 10-K for the fiscal year ended December 31, 2004, as amended, for a more complete description of the Development Wells.)

During 2004, an oil and gas company contacted Eastern American and inquired as to whether it would sell certain assets situated in Centre County, Pennsylvania including the Horne #1, Horne #2 and Horne #15 wells (the Horne Underlying Properties), which are wells in which the Trust owns a Net Profits Interests. Eastern American reviewed the Trust Agreement and certified to the Trustee that: (i) the gross purchase price to be received by Eastern American for the sale of the Horne Underlying Properties in a single transaction or a series of related transactions is less than $500,000; (ii) the Assignee of the Horne Underlying Properties is not an Affiliate of Eastern American; (iii) the aggregate sale proceeds of $80,205 to be received by the Trust from Eastern American (the Trust s Horne Sale Proceeds) represents the fair value to the Trust for Net Profits Interests to be released by the Trustee in connection with Eastern American s sale of the Horne Underlying Properties; and (iv) the Trust s Horne Sale Proceeds plus the aggregate sale proceeds received by the Trust pursuant to Section 3.02(b)(ii) of the Trust Agreement with respect to all other Net Profits Interests previously released by the Trustee pursuant to Section 3.02(b) during the most recently completed twelve calendar months did not exceed $500,000. Eastern American advised the oil and gas company that it could sell these wells. The effective date of the sale was May 1, 2004. The Trust s share of the proceeds of $80,205 was included in the Distributable Income of the Trust during the quarter ended June 30, 2004.

Also, during 2004, a landowner contacted Eastern American to inquire about the sale of certain wells located on the landowner s property, including the Wurst #2 well, which is a well in which the Trust owns a Net Profits Interest. Eastern certified to the Trust that: (i) the Assignee of the Wurst #2 was not an Affiliate of Eastern and; (ii) the aggregate sale proceeds to be received from all other sales of wells in which the Trust owns a Net Profits Interest and previously released by the Trust during the preceeding twelve (12) calendar months did not exceed $500,000. The Wurst #2 well was found to be uneconomic to operate and was subject to plugging and abandonment by Eastern American if not assigned to the landowner. Eastern American advised the landowner that it could assign this well. The Wurst #2 well had no value and no cash distribution was made to the Trust.

Over the remaining life of the Trust, additional wells may be disposed of for similar or other reasons.

During the quarter ended September 30, 2005, the Trust incurred substantially increased fees for professional services relating to the potential exchange offer described below under Other Information . These expenses, and any related expenses, will decrease distributions to the Unitholders. Expenses relating to the potential exchange offer actually incurred by the Trust during the quarter ended September 30, 2005 include a $100,000 fee paid to the independent financial advisor retained by the Trust to assist with an evaluation of the potential exchange offer, and approximately $50,000 in additional legal fees relating to the potential exchange offer. The terms of the engagement agreement with the financial advisor would require the Trust to pay the financial advisor (i) an additional $150,000 if the Trust requests that a description of the financial advisor s analysis of the exchange offer be included in any filings or materials to be delivered to the Unitholders, or (ii) an additional $300,000 if the Trust requests a written opinion from the financial advisor as to whether the offer (if made) is fair, from a financial point of view, to the Unitholders. In addition, the Trust has incurred and is likely to continue to incur increased legal and other expenses relating to the potential exchange offer. Further, the Trust has incurred an additional expense of approximately $13,200 payable to the Trust s independent petroleum engineers for the updated reserve report described below under Other Information and filed herewith as Annex A. The aggregate amount of future additional expenses may be substantially greater.

Critical Accounting Policies

The following is a summary of the critical accounting policies followed by the Trust.

Basis of Accounting:

The financial statements of the Trust differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America due to the following: (i) certain cash reserves may be established for contingencies which were not accrued in the financial statements; (ii) amortization of the Net Profits Interests in gas properties is charged directly to Trust Corpus; and (iii) the sale of the Net Profits Interests is reflected in the Statements of Distributable Income as cash proceeds to the Trust.

Net Profits Interests in Gas Properties:

The Net Profits Interests in gas properties are periodically assessed to determine whether their net capitalized cost is impaired. The Trust will determine if a writedown is necessary to its investment in the Net Profits Interests in gas properties to the extent that total capitalized costs, less accumulated amortization, exceed undiscounted future net revenues attributable to proved gas reserves of the Underlying Properties. The Trust will then provide a writedown to the extent that the net capitalized costs exceed the discounted future net revenues attributable to proved gas reserves of the Underlying

Properties. Any such writedown would not reduce distributable income, although it would reduce Trust Corpus.

Amortization of the Net Profits Interests in gas properties is calculated on a units-of-production basis, whereby the Trust s cost basis in the properties is divided by total Trust proved reserves to derive an amortization rate per reserve unit. Such amortization does not reduce distributable income, rather it is charged directly to Trust Corpus. Revisions to estimated future units-of-production are treated on a prospective basis beginning on the date significant revisions are known.

The Net Profits Interest impairment test and the determination of amortization rates are dependent on estimates of proved gas reserves attributable to the Trust. Numerous uncertainties are inherent in estimating reserve volumes and values, including economic and operating conditions, and such estimates are subject to change as additional information becomes available.

Liquidity and Capital Resources

The Trust has no source of liquidity or capital resources other than the distributions received from the Net Profits Interests.

In accordance with the provisions of the Conveyances, generally all revenues received by the Trust, net of Trust administrative and operating expenses and the amount of established reserves, are distributed currently to the Unitholders.

The Trust did not have any contractual obligations as of September 30, 2005. At September 30, 2005, the Trust had accounts payable of $164,561 and distributions payable of $3,799,774.

<u>Comparison of Results of Operations for Three Months Ended September 30, 2005 and Three Months Ended September 30, 2004</u>

The Trust s distributable income was $3,799,774 for the three months ended September 30, 2005 as compared to $2,849,395 for the three months ended September 30, 2004. This increase was due to an increase in Royalty Income for the three months ended September 30, 2005 to $4,659,185 as compared to the three months ended September 30, 2004 of $3,452,442. The increase in Royalty Income was due to an increase in the price payable to the Trust under the Gas Purchase Contract as discussed below ($9.268 per Mcf for the three months ended September 30, 2005; $7.106 per Mcf for the three months ended September 30, 2004). This increase was also due to an increase in production of gas attributable to the Net Profits Interests for the three months ended September 30, 2005 (504 Mmcf) as compared to the three months ended September 30, 2004 (485 Mmcf). The increase in production is primarily attributable to shut-ins during the quarter ended September 30, 2004. Taxes on production and property were $320,484 for the three months ended September 30, 2005 as compared to $232,004 for the three months ended September 30, 2004. The increase in taxes is due directly to the increase in Royalty Income as discussed above. Trust general and administrative expenses were $405,340 for the three months ended September 30, 2005 as compared to $242,168 for the three months ended September 30, 2004. This increase in general and administrative expense of $163,172 was primarily related to an increase in professional service fees for costs associated with services provided to the Trustee relating to the potential exchange offer described below under Other Information .

12

The price payable to the Trust for gas production attributable to the Net Profits Interests was $9.268 per Mcf for the three months ended September 30, 2005 and $7.106 per Mcf for the three months ended September 30, 2004. The price per Mcf was higher for the three months ended September 30, 2005 than for the corresponding three month period ended September 30, 2004 due to an increase in the average spot market price for gas delivered at the Henry Hub near Henry, Louisiana ($8.125 per Dth for the three months ended September 30, 2005; $6.160 per Dth for the three months ended September 30, 2004).

Comparison of Results of Operations for Nine Months Ended September 30, 2005 and Nine Months Ended September 30, 2004

The Trust s distributable income was $9,963,937 for the nine months ended September 30, 2005 as compared to $8,379,863 for the nine months ended September 30, 2004. This increase was due to an increase in Royalty Income for the nine months ended September 30, 2005 to $12,221,141 as compared to $10,024,331 for the nine months ended September 30, 2004. The increase in Royalty Income was due to an increase in the average price payable to the Trust under the Gas Purchase Contract as discussed below ($8.221 per Mcf for the nine months ended September 30, 2005; $6.645 per Mcf for the nine months ended September 30, 2004). This increase was offset by a decrease in production of gas attributable to the Net Profits Interests for the nine months ended September 30, 2005 (1,487 Mmcf) as compared to the nine months ended September 30, 2004 (1,508 Mmcf). The decline in production is primarily attributable to natural production declines and the sale of wells. Taxes on production and property were $839,691 for the nine months ended September 30, 2005 as compared to $683,658 for the nine months ended September 30, 2004. The increase in taxes is due directly to the increase in Royalty Income as discussed above. Trust general and administrative expenses were $1,017,252 for the nine months ended September 30, 2005 as compared to $651,903 for the nine months ended September 30, 2004. This increase in general and administrative expense of $365,349 was primarily related to an increase in professional service fees for costs associated with the procedures required by the Sarbanes-Oxley Act of 2002 and costs associated with services provided to the Trustee relating to the potential exchange offer described below under Other Information . During the nine months ended September 30, 2005, the Trustee added $185,000 to the reserve as compared to $100,000 for the nine months ended September 30, 2004. The Trustee established this reserve amount to facilitate the payment of vendor invoices on a timely basis. The distributable income includes no Cash Proceeds on Sale of Net Profits Interests for the nine months ended September 30, 2005, while $80,205 was recognized in the corresponding nine months of the prior year. Amortization of Net Profits Interests in Gas Properties was $2,524,092 for the nine months ended September 30, 2005 as compared to $2,785,090 for the nine months ended September 30, 2004. This decrease was primarily due to the decrease in production volumes.

The average price payable to the Trust for gas production attributable to the Net Profits Interests was $8.221 per Mcf for the nine months ended September 30, 2005 and $6.645 per Mcf for the nine months ended September 30, 2004. The price per Mcf was higher for the nine months ended September 30, 2005 than for the corresponding nine month period ended September 30, 2004 due to an increase in the average spot market price for gas delivered at the Henry Hub near Henry, Louisiana ($7.173 per Dth for the nine months ended September 30, 2005; $5.741 per Dth for the nine months ended September 30, 2004).

Off-Balance Sheet Arrangements

The Trust does not have any off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on the Trust s financial condition, changes in financial condition, revenue or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Other Information

United States Treasury Obligations

For the calendar quarter ended September 30, 2005, the high and low closing prices of the Treasury Obligations (which have $1,000 face principal amount), as quoted in the over-the-counter market for United States Treasury obligations were $734.41 and $708.72, respectively. On September 30, 2005, the closing price of the Treasury Obligations, as quoted on such market, was $720.34.

The Trust provides Unitholders with the option to separate the related Treasury Obligation from the Trust Units. Upon exercising this option, the Trustee transfers such Trust Units from the name of the Depositary to the name of the withdrawing Unitholder. As of September 30, 2005, this option was exercised on 19,900 Trust Units. (See the Trust s 10-K for the fiscal year ended December 31, 2004 for a more complete description of the Withdrawal of Trust Units and Restriction on Transfer.)

Ensource Energy Income Fund LP

The Trustee is aware that Ensource Energy Income Fund LP, a recently formed Delaware limited partnership not affiliated with the Trust (Ensource), has filed a Registration Statement on Form S-4 with the Securities and Exchange Commission. The filing describes a proposed transaction pursuant to which Ensource would attempt to acquire control of, and ultimately the entire interest in, the Trust.

The Trustee cannot predict whether Ensource will proceed with the proposed transaction or, if it does proceed, whether Ensource will be able to acquire a majority of the outstanding Trust units or, if it does acquire a majority of the outstanding units, whether it will proceed with or be able to consummate the second-step merger described in the Form S-4.

If Ensource proceeds with the proposed transaction on the terms described in the Form S-4, the Trust will be required by rules of the SEC to make a recommendation whether Unitholders should accept or reject the exchange offer or to state that the Trust is remaining neutral with respect to the exchange offer. The Trust has retained a financial advisor to assist the Trust with an evaluation of any such exchange offer. The Trust has also received a letter from the operator of the underlying properties and original sponsor of the Trust, Eastern American, stating that Eastern American s initial review of the Form S-4 leads Eastern American to believe that the Ensource proposal substantially changes the original structure and business risk exposure of the Trust and exposes the Unitholders to the vagaries of the oil and gas business, and as such, may not be in the best interest of the Unitholders. In the letter, Eastern American made a number of specific comments regarding the proposed

exchange offer and noted that it has yet to form an opinion as to which, if any, of the underlying documents may or may not continue in effect subsequent to the proposed exchange.

Updated Reserves Report

Introduction. The Trust normally obtains a report of oil and gas reserves attributable to the Trust as of the end of the calendar year prepared by Ryder Scott Company, which is an independent petroleum engineering firm, and the Trust normally includes a copy of that annual report in its Annual Report on Form 10-K. In light of the potential exchange offer that Ensource may make to the Unitholders as described briefly above, the Trust determined that it would be prudent and in the best interests of the Unitholders to obtain an updated reserve report so that Unitholders would have the benefit of a relatively current report in the event that Ensource proceeds with its proposed exchange offer. The Trust therefore engaged Ryder Scott Company to prepare an updated report as of September 1, 2005, a copy of which is included as Annex A to this Form 10-Q. The information in the report is subject to the same limitations and qualifications as are applicable to prior reports prepared by Ryder Scott Company, as described in the report and in the Trust s Annual Report on Form 10-K for the year ended December 31, 2004. Following is a summary of the information contained in the updated reserve report.

Proved Reserves of Underlying Properties and Net Profits Interests. The following table sets forth, as of September 1, 2005, certain estimated proved reserves, estimated future net revenues and the discounted present value thereof attributable to the Underlying Properties, the Royalty NPI and the Term NPI, in each case derived from a report of oil and gas reserves attributable to the Trust as of September 1, 2005 prepared by Ryder Scott Company (the Reserve Report). Proved reserve quantities attributable to the Net Profits Interests are calculated by subtracting an amount of gas sufficient, if sold at the prices used in preparing the reserve estimates, to pay the future estimated costs and expenses deducted in the calculation of Net Proceeds. Accordingly, the reserves attributable to the Net Profits Interests reflect quantities of gas that are free of future costs or expenses if the price and cost assumptions set forth in the Reserve Report occur. A decrease in the price assumption, or an increase in the cost assumption used in the Reserve Report would reduce the estimates of proved reserves, future net revenues and discounted future net revenues, set forth herein and in the Reserve Report. The Term NPI excludes production beyond the earlier of May 15, 2013 or such time as 41,683 MMcf of gas has been produced which is attributable to Eastern American s net revenue interests in the properties burdened by the Term NPI. The discounted present value of estimated future net revenues was determined using a discount rate of 10% in accordance with applicable requirements. A copy of the Reserve Report is included as Annex A hereto.

	Proved Gas Reserves (MMcf) Developed	Undeveloped	Total	Estimated Future Net Revenues(2) (Dollars in thousands)	Discounted Estimated Future Net Revenues(2)
Underlying Properties(1)	35,107	0	35,107	$ 278,698	$ 113,611
Net Profits Interests:					
Royalty NPI	11,052	0	11,052	$ 102,428	$ 43,327
Term NPI	6,272	0	6,272	58,128	41,833
Total	17,324	0	17,324	$ 160,556	$ 85,160

(1)Reserve volumes and estimated future net revenues for Underlying Properties reflect volumes and revenues distributable to Eastern American s entire net revenue interest with respect to the Underlying Properties.

(2)The effects of depreciation, depletion and federal income tax have not been taken into account in estimating future net revenues. Estimated future net revenues and discounted estimated future net revenues are not intended, and should not be interpreted, as representing the fair market value for the estimated reserves.

The value of the Depositary Units and the Trust Units evidenced thereby are substantially dependent upon the proved reserves and production levels attributable to the Net Profits Interests. There are many uncertainties inherent in estimating quantities and values of proved reserves and in projecting future rates of production and the timing of development expenditures, if any. The reserve data set forth herein, although prepared by independent engineers in a manner customary in the industry, are estimates only, and actual quantities and values of gas are likely to differ from the estimated amounts set forth herein. In addition, the discounted present values shown herein were prepared using guidelines established by the Securities and Exchange Commission and Financial Accounting Standards Board for disclosure of reserves and should not be considered representative of the market value of such reserves or the Depositary Units or the Trust Units evidenced thereby. A market value determination would include many additional factors.

The price assumptions used by Ryder Scott Company in preparing the updated reserve report were furnished to Ryder Scott Company by Eastern American Energy Corporation and were prepared in accordance with applicable SEC guidelines and the terms of the Gas Purchase Contract between the Trust and Eastern Marketing Corporation. The price under the Gas Purchase Contract as of August 31, 2005 was $9.268 per Mcf and was based on the Henry Hub Average Spot Price (as defined in the Gas Purchase Contract) of $8.125 per Mmbtu.

If Ensource proceeds with the proposed exchange offer, Unitholders will receive further information regarding the exchange offer and any recommendation the Trust may make.

ITEM 3. Quantitative and Qualitative Disclosures about Market Risk

The Trust does not engage in any operations, and does not utilize market risk sensitive instruments, either for trading purposes or for other than trading purposes. As described elsewhere herein, the

16

Depositary Units consist of beneficial ownership of one unit of beneficial interest in the Trust and a $20 face amount beneficial ownership interest in a $1,000 face amount zero coupon Treasury Obligation maturing on May 15, 2013. High and low price information for the Treasury Obligations is included under Part II Item 5. As described elsewhere herein, gas production attributable to the Net Profits Interest is sold to a wholly owned subsidiary of Eastern American pursuant to the Gas Purchase Contract described herein, and the Trust s quarterly distributions are highly dependent on the price payable to the Trust for gas production attributable to the Net Profits Interest. Natural gas prices can fluctuate widely in response to many factors, all of which are out of the control of the Trust, the Trustee and Eastern American.

ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. The Trustee maintains disclosure controls and procedures designed to provide reasonable assurance that information required to be disclosed by the Trust in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and regulations. Disclosure controls and procedures include controls and procedures designed to provide reasonable assurance that information required to be disclosed by the Trust is accumulated and communicated by several parties, including without limitation, the working interest owner, Eastern American, and the independent reserve engineer to JPMorgan Chase Bank, N.A., as Trustee of the Trust, and its employees who participate in the preparation of the Trust s periodic reports as appropriate to allow timely decisions regarding required disclosure. In addition, the Trustee is required by the Trust Agreement to engage and has engaged an independent registered public accounting firm to review the quarterly financial statements of the Trust and audit the annual financial statements of the Trust, which includes financial data provided by Eastern American.

As of September 30, 2005, the Trustee carried out an evaluation of the Trustee s disclosure controls and procedures, as defined under Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act. Mike Ulrich, a Vice President of JPMorgan Chase Bank, N.A., has concluded that the controls and procedures are effective at the reasonable assurance level, while noting certain limitations on disclosure controls and procedures as set forth below.

Due to the contractual arrangements of (i) the Trust Agreement, and (ii) the rights of the Trustee under the Conveyances regarding information furnished by Eastern American, there are certain potential weaknesses that may limit the effectiveness of disclosure controls and procedures established by the Trustee or its employees and their ability to verify the accuracy of certain financial information. The contractual limitations creating potential weaknesses in disclosure controls and procedures may be deemed to include:

Eastern American and its consolidated subsidiaries manage (i) historical operating data, including production volumes, marketing of products, operating and capital expenditures, environmental and other liabilities, the effects of regulatory changes and the number of producing wells and acreage; (ii) plans for future operating and capital expenditures; and (iii) geological data relating to reserves. While the Trustee requests material information for use in periodic reports as part of its disclosure controls and procedures, the Trustee does not manage this information, and relies to the extent considered reasonable on Eastern American to provide accurate and timely information when requested for use in the Trust s reports.

Under the terms of the Trust Agreement, the Trustee is entitled to, and in fact does, rely upon in good faith the independent reserve engineer, as an expert with respect to the annual reserve report, which includes projected production, operating expenses and capital expenses. Other than reviewing the financial and other information provided to the Trust by Eastern American on a quarterly basis, the Trustee makes no independent or direct verification of this financial or other information. While the Trustee has no reason to believe its reliance upon this expert is unreasonable, this reliance on an expert and restricted access to information may be viewed as a weakness.

The Trustee does not intend to expand its responsibilities beyond those permitted or required by the Trust Agreement and those required under applicable law.

Changes in Internal Control Over Financial Reporting

There has been no change in the Trustee s internal control over financial reporting during the three months ended September 30, 2005 that has materially affected, or is reasonably likely to materially affect, the Trustee s internal control over financial reporting. The Trustee notes for purposes of clarification that it has no authority over, and makes no statement concerning, the internal control over financial reporting of Eastern American.

PART II OTHER INFORMATION

ITEM 1. Legal Proceedings.

None.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds.

None.

ITEM 3. Defaults Upon Senior Securities.

None.

ITEM 4. Submission of Matters to a Vote of Security Holders.

None.

ITEM 5. Other Information.

None.

ITEM 6. Exhibits.

Exhibit Number	Description
3.1*	Second Amended and Restated Trust Agreement of Eastern American Natural Gas Trust
4.1*	Specimen Depositary Receipt
4.2*	Form of NPI Royalty Deposit Agreement
10.1*	Form of Conveyance
10.2*	Form of Term NPI Conveyance
10.3*	Form of Gas Purchase Contact between Eastern American Energy Corporation, Eastern Marketing Corporation and Eastern American Natural Gas Trust
10.5*	Form of Conveyance of Production Payment/Assignment of Production from Eastern American Natural Gas Trust to Eastern Marketing Corporation
10.6*	Form of Assignment and Standby Performance Agreement
23.1	Consent of Ryder Scott Company
31.	Rule 13a-14(a)/15d-14(a) Certification
32.	Section 1350 Certification

* Incorporated by reference to the indicated exhibits to filings previously made by the registrant with the Securities and Exchange Commission. All references are to the registrant s Registration Statement on Form S-1, Registration No. 33-56336, except for Exhibit 3.1, which is incorporated by reference to the Registrant s Annual report on Form 10-K for the year ended December 31, 1994.

621 17TH STREET, SUITE 1550 DENVER, COLORADO 80293 TEL (303) 623-9147 FAX (303) 623-4258

October 13, 2005

J P Morgan Chase Bank, N.A., Trustee

Institutional Trust Services

700 Lavaca, 2nd Floor

Austin, Texas 78701

Gentlemen:

Pursuant to your request, we present below estimates of the net proved reserves attributable to the interests of the Eastern American Natural Gas Trust (Trust) as of September 1, 2005. The Trust is a grantor trust formed to hold interests in certain domestic oil and gas properties owned by Eastern American Energy Corporation (EAEC), a wholly owned subsidiary of Energy Corporation of America (ECA). The interests conveyed to the Trust consist of a net profits interest derived from working and royalty interests in numerous properties. The Net Profits Interest consists of (1) a life-of-properties interest (Royalty NPI) and (2) a term interest (Term NPI). The properties included in the Trust are located in the states of Pennsylvania and West Virginia.

The estimated reserve quantities and future income quantities presented in this report are related to a large extent to hydrocarbon prices. Hydrocarbon prices in effect at August 31, 2005 were used in the preparation of this report as required by Securities and Exchange Commission (SEC) and Financial Accounting Standards Bulletin No. 69 (FASB 69) guidelines; however, actual future prices may vary significantly from August 31, 2005 prices for reasons discussed in more detail in other sections of this report. Therefore, quantities of reserves actually recovered and quantities of income actually received may differ significantly from the estimated quantities presented in this report.

	Gas (MMCF)	As of September 1, 2005 Estimated Future Net Cash Inflows (M$)	Present Value At 10% (M$)
Proved Net Developed			
Royalty NPI	11,052	102,428	43,327
Term NPI	6,272	58,128	41,833
Total	17,324	160,556	85,160

Reserve quantities are calculated differently for a Net Profits Interest because such interests do not entitle the Trust to a specific quantity of oil or gas but to 90 percent of the Net Proceeds derived therefrom beginning on September 1, 2005 for natural gas. Accordingly, there is no precise method of allocating estimates of the quantities of proved reserves attributable to the Net Profits Interest between the interest held by the Trust and the interests to be retained by EAEC. For purposes of this presentation, the proved reserves attributable to the Net Profits Interests have been proportionately reduced to reflect the future estimated costs and expenses deducted in the calculation of Net Proceeds with respect to the Net Profits Interests. Accordingly, the reserves presented for the Net Profits Interest reflect quantities of gas that are free of future costs or expenses based on the price and cost assumptions utilized in this report. The allocation of proved reserves of the Net Profits Interest between the Trust and EAEC will vary in the future as relative estimates of future gross revenues and future net incomes vary. Furthermore, EAEC requested that for purposes of our report the Royalty NPI be calculated beyond the Liquidation Date of May 15, 2013, even though by the terms of the Trust Agreement the Royalty NPI will be sold by the Trustee on or about this date and a liquidating distribution of the sales proceeds from such sale would be made to holders of Trust Units. The Trust Agreement provides that the Term NPI entitles the Trust to receive the net proceeds from the gas produced from the properties burdened by the Term NPI until the earlier of May 15, 2013 or until such time as 41,683 MMCF of gas has been produced. For purposes of this report, the Term NPI was limited to May 15, 2013.

All gas volumes are sales gas expressed in MMCF at the pressure and temperature bases of the area where the gas reserves are located. The estimated future net cash inflows are described later in this report.

The proved reserves presented in this report comply with the Securities and Exchange Commission s Regulation S-X Part 210.4-10 Sec. (a) as clarified by subsequent Commission Staff Accounting Bulletins, and are based on the following definitions and criteria:

Proved reserves of crude oil, natural gas, or natural gas liquids are estimated quantities that geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under existing conditions. Reservoirs are considered proved if economic producibility is supported by actual production or formation tests. In certain instances, proved reserves may be assigned on the basis of a combination of core analysis and electrical and other type logs which indicate the reservoirs are analogous to reservoirs in the same field which are producing or have demonstrated the ability to produce on a formation test. The area of a reservoir considered proved includes (1) that portion delineated by drilling and defined by fluid contacts, if any, and (2) the adjoining portions not yet drilled that can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of data on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Proved reserves are estimates of hydrocarbons to be recovered from a given date forward. They may be revised as hydrocarbons are produced and additional data becomes available. Proved natural gas reserves consist of non-associated, associated and dissolved gas. An appropriate reduction in gas reserves has been made for the expected removal of natural gas liquids, for lease and plant fuel, and for the exclusion of non-hydrocarbon gases if they occur in significant quantities.

Reserves that can be produced economically through the application of improved recovery techniques are included in the proved classification when these qualifications are met: (1) successful testing by a pilot project or the operation of an installed program in the reservoir provides support for the engineering analysis on which the project or program was based, and (2) it is reasonably certain the project will proceed. Improved recovery includes all methods for supplementing natural reservoir forces and energy, or otherwise increasing ultimate recovery from a reservoir, including (1) pressure maintenance, (2) cycling, and (3) secondary recovery in its original sense. Improved recovery also includes the enhanced recovery methods of thermal, chemical flooding, and the use of miscible and immiscible displacement fluids.

Estimates of proved reserves do not include crude oil, natural gas, or natural gas liquids being held in underground or surface storage.

(i) developed reserves which are those proved reserves reasonably expected to be recovered through existing wells with existing equipment and operating methods, including (a) developed producing reserves which are those proved developed reserves reasonably expected to be produced from existing completion intervals now open for production in existing wells, and (b) developed non-producing reserves which are those proved developed reserves which exist behind the casing of existing wells which are reasonably expected to be produced through these wells in the predictable future where the cost of making such hydrocarbons available for production should be relatively small compared to the cost of a new well; and

(ii) undeveloped reserves which are those proved reserves reasonably expected to be recovered from new wells on undrilled acreage, from existing wells where a relatively large expenditure is required and from acreage for which an application of fluid injection or other improved recovery technique is contemplated where the technique has been proved effective by actual tests in the area in the same reservoir. Reserves from undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are included only where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation.

In accordance with the requirements of FASB 69, estimates of future cash inflows, future costs and future net cash inflows before income tax, as well as estimated reserve quantities, as of September 1, 2005 from this report are presented in the following table:

	As of September 1, 2005		
	Royalty NPI	**Term NPI**	**Totals**
Total Proved			
Future Cash Inflows (M$)	102,428	58,128	160,556
Future Costs			
Production (M$)	0	0	0
Development (M$)	0	0	0
Total Costs (M$)	0	0	0
Future Net Cash Inflows Before Income Tax (M$)	102,428	58,128	160,556
Present Value at 10% Before Income Tax (M$)	43,327	41,833	85,160

	As of September 1, 2005		
	Royalty NPI	**Term NPI**	**Totals**
Proved Net Developed Reserves			
Gas (MMCF)	11,052	6,272	17,324
Proved Net Undeveloped Reserves			
Gas (MMCF)	0	0	0
Total Proved Net Reserves			
Gas (MMCF)	11,052	6,272	17,324

For Net Profits Interest, the future cash inflows are, as described previously, after consideration of future costs or expenses based on the price and cost assumptions utilized in this report. Therefore, the future cash inflows are the same as the future net cash inflows. The effects of depreciation, depletion and federal income taxes have not been taken into account in estimating future net cash inflows.

EAEC furnished us gas prices in effect at August 31, 2005 and with its forecasts of future gas prices which take into account Securities and Exchange Commission guidelines, current market prices, contract prices and fixed and determinable price escalations where applicable. In accordance with Securities and Exchange Commission guidelines, the future gas prices used in this report make no allowances for future gas price increases or decreases which may occur as a result of inflation nor do they account for seasonal variations in gas prices which are likely to cause future yearly average gas prices to be somewhat higher than August gas prices. In those cases where contract market-out has occurred, the current market price was held constant to depletion of the reserves. In those cases where market-out has not occurred, contract gas prices including fixed and determinable escalations, exclusive of inflation adjustments, were used until the contract expired and then reduced to the current market price for similar gas in the area and held at this reduced price to depletion of the reserves.

This report utilized the terms of the gas contract between Eastern Marketing Corporation (a wholly owned subsidiary of EAEC) and the Trust. Gas price is to be determined by a weighted price consisting of two components during a primary term defined to begin on January 1, 1993 and end December 31, 1999. The first component is the Fixed price which has been defined as $2.66 per Mcf beginning January 1, 1993. This price escalates 5 percent per year on January 1 of each year during the primary term beginning in 1994. The second component is the Variable price which for any quarter is equal to the Henry Hub Average Spot Price (as defined) per MMBtu, plus $0.30 per MMBtu, multiplied by 110 percent to effect a Btu adjustment. The Henry Hub Average Spot Price is defined as the price per MMBtu determined for any calendar quarter as the average price of the three months in such quarter where each month s price is equal to the average of (i) the final settlement prices per MMBtu for Henry Hub Gas Futures Contracts (as defined), as reported in the Wall Street Journal, for such contracts which expired in each of the five months prior to each month of such quarter, (ii) the final settlement price per MMBtu for Henry Hub Gas Futures Contracts, as reported in the Wall Street Journal, for such contracts which expire during such month and (iii) the closing settlement prices per MMBtu of Henry Hub Gas Futures Contracts for such month, as reported in the Wall Street Journal, for such contracts which expire in each of the six months following such month. A Henry Hub Gas Futures Contract is defined as a gas futures contract for gas to be delivered to the Henry Hub which is traded on the New York Mercantile Exchange. The weighted average price is determined by giving the Fixed price a 66 2/3 percent weighting and the variable price a 33 1/3 percent weighting.

Since the primary term is complete, the purchase price under the gas contract will be equal to the Variable price. EAEC computed the Variable price under the gas contract as of August 31, 2005 as $9.268 per Mcf, utilizing $8.125 as the Henry Hub Average Spot Price computed in accordance with the gas contract.

Operating costs for the leases and wells in this report were supplied by EAEC and include only costs defined as applicable under terms of the Trust. The current operating costs were held constant throughout the life of the properties. This study does not consider the salvage value of the lease equipment or the abandonment cost.

No deduction was made for indirect costs such as general administration and overhead expenses, loan repayments, interest expenses, and exploration and development prepayments. No attempt has been made to quantify or otherwise account for any accumulated gas production imbalances that may exist.

Our reserve estimates are based upon a study of the properties in which the Trust has interests; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities which may exist nor were any costs included for potential liability to restore and clean up damages, in any, caused by past operating practices. EAEC informed us that it has furnished us all of the accounts, records, geological and engineering data and reports and other data as were required for our investigation. The ownership interests, terms of the Trust, prices, taxes, and other factual data furnished to us in connection with our investigation were accepted as represented. The estimates presented in this report are based on data available through July, 2005.

At the time of formation of the Trust, EAEC assigned The Trust an interest in 65 undeveloped locations. During the period 1993 through 1998, EAEC has completed it s drilling obligation. A total of 59 wells were drilled over this period. Two wells were not drilled due to title failure and four wells were not drilled due to short spacing. Reserves and projections of future production are included for the four locations which were not drilled due to short spacing.

The reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered. Moreover, estimates of proved reserves may increase or decrease as a result of future operations of EAEC. Moreover, due to the nature of the Net Profits Interest, a change in the future costs, or prices different from those projected herein may result in a change in the computed reserves and the Net Proceeds to the Trust even if there are no revisions or additions to the gross reserves attributed to the property.

The future production rates from properties now on production may be more or less than estimated because of changes in market demand or allowables set by regulatory bodies.

The future prices received by EAEC for the sale of its production may be higher or lower than the prices used in this report as described above, and the operating costs and other costs relating to such production may also increase or decrease from existing levels; however, such possible changes in prices and costs were, in accordance with rules adopted by the Securities and Exchange Commission, omitted from consideration in preparing this report.

At the request of EAEC, we have included the following table which summarizes the total net reserves estimates from combined interest of EAEC and the Trust in the Underlying Properties:

Estimated Net Reserve Data

Certain Combined Leasehold Interests of

Eastern America Energy Corporation

And The Trust

As of September 1, 2005

SEC Parameters

	Proved		Total
	Developed	**Undeveloped**	**Proved**
Net Remaining Reserves			
Gas-MMCF	35,107	0	35,107

The estimated future net income associated with the foregoing volumes and the 10 percent discounted estimated future net income was $278,698,330 and $113,611,262, respectively. This evaluation utilizes the same price and cost assumptions that were utilized for evaluating the Trust and discussed earlier in the letter. The properties which are included in the Term NPI were allowed to run for their full economic life in this evaluation.

Neither Ryder Scott Company nor any of its employees has any interest in the subject properties and neither the employment to make this study nor the compensation is contingent on our estimates of reserves and future cash inflows for the subject properties.

Very truly yours,

RYDER SCOTT COMPANY, L.P.

Larry T. Nelms P. E.
Managing Senior Vice President

LTN:ph

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.

EASTERN AMERICAN NATURAL GAS TRUST

By: JPMorgan Chase Bank, N.A., Trustee

/s/ Mike Ulrich

Name:	Mike Ulrich
Title:	Vice President
	JPMorgan Chase Bank, N.A.

Date: November 8, 2005

The Registrant, Eastern American Natural Gas Trust, has no principal executive officer, principal financial officer, board of directors or persons performing similar functions. Accordingly, no additional signatures are available and none have been provided.