ALPINE GLOBAL DYNAMIC DIVIDEND FUND
Form DEF 14A
January 29, 2010

SCHEDULE 14A INFORMATION

Proxy Statement Pursuant to Section 14(a)

of the Securities Exchange Act of 1934

Filed by the Registrant x

Filed by a Party other than the Registrant o

Check the appropriate box:

o	Preliminary Proxy Statement
o	**Confidential, for Use of the Commission Only (as permitted by Rule 14a-6(e)(2))**
x	Definitive Proxy Statement
o	Definitive Additional Materials
o	Soliciting Material Pursuant to § 240.14a-11(c) or § 240.14a-12

ALPINE GLOBAL DYNAMIC DIVIDEND FUND
(Name of Registrant as Specified in its Charter)

(Name of Person(s) Filing Proxy Statement, if other than the Registrant)

Payment of Filing Fee (check the appropriate box):

x No fee required.

o Fee computed on table below per Exchange Act Rules 14a-6(i)(1) and 0-11.

(1)	Title of each class of securities to which transaction applies: N/A
(2)	Aggregate number of securities to which transaction applies: N/A
(3)	Per unit price or other underlying value of transaction computed pursuant to Exchange Act Rule 0-11 (set forth the amount on which the filing fee is calculated and state how it was determined): N/A
(4)	Proposed maximum aggregate value of transaction: N/A
(5)	Total fee paid: N/A

o Fee paid previously with preliminary materials.

o Check box if any part of the fee is offset as provided by Exchange Act Rule 0-11(a)(2) and identify the filing for which the offsetting fee was paid previously. Identify the previous filing by registration statement number, or the Form or Schedule and the date of its filing.

(1)	Amount previously paid: N/A
(2)	Form, Schedule or Registration Statement No.: N/A
(3)	Filing Party: N/A
(4)	Date Filed: N/A

Alpine Global Dynamic Dividend Fund
c/o ALPS Fund Services, Inc.
1290 Broadway, Suite 1100
Denver, Colorado 80203

January 29, 2010

Dear Shareholder:

We are writing to inform you of the upcoming annual meeting of shareholders of the Alpine Global Dynamic Dividend Fund, a Delaware statutory trust (the "Fund") scheduled to be held on March 18, 2010 (the "Annual Meeting") to elect two Trustees to the Board of Trustees (the "Board") each to serve for a three-year term or until his successor has been duly elected and qualified. This proposal is discussed in more detail in the Fund's Proxy Statement, which you should read carefully. The Board believes that this proposal is in the best interests of the Fund and its shareholders, and unanimously recommends that you vote "**FOR**" the election of James A. Jacobson and H. Guy Leibler as Trustees.

If you are a shareholder of record as of the close of business on January 15, 2010, you are entitled to vote at the Annual Meeting and at any adjournment thereof. While you are, of course, welcome to join us at the Annual Meeting, most shareholders will cast their votes by filling out and signing the Proxy Card. The Board has recommended the election of Messrs. Jacobson and Leibler as Trustees and encourages you to vote "**FOR**" their election. If you have any questions regarding the issue to be voted on, please do not hesitate to call the Fund at 1-800-617-7616. Whether or not you are planning to attend the Annual Meeting, we need your vote. Please mark, sign, and date the Proxy Card and promptly return it, so that the maximum number of shares may be voted.

Thank you for taking the time to consider this important proposal and for your continuing investment in the Fund.

Sincerely,

ALPINE GLOBAL DYNAMIC DIVIDEND FUND

Samuel A. Lieber, *President*

Alpine Global Dynamic Dividend Fund
c/o ALPS Fund Services, Inc.
1290 Broadway, Suite 1100
Denver, Colorado 80203

NOTICE OF ANNUAL MEETING
TO BE HELD MARCH 18, 2010

Important Notice Regarding the Availability of Proxy Materials for the Annual Meeting of Shareholders to be Held on March 18, 2010. The Proxy Statement is available at www.proxyonline.com/docs/Alpineglobaldynamicdividendfund.pdf.

To the shareholders of the Alpine Global Dynamic Dividend Fund, a Delaware statutory trust (the "Fund"):

Notice is hereby given that the Annual Meeting (the "Meeting") of shareholders of the Fund will be held on March 18, 2010, at 11:00 a.m., Eastern Time, at 707 Westchester Avenue, White Plains, New York 10604. At the Meeting, you and the other shareholders of the Fund will be asked to consider and vote:

1. To elect Messrs. James A. Jacobson and H. Guy Leibler as Trustees to the Board of Trustees for a term of three years until their successor has been duly elected and qualified.

2. To transact such other business as may properly come before the Meeting or any adjournments thereof.

The proposal is discussed in greater detail in the Fund's Proxy Statement. Shareholders of record at the close of business on January 15, 2010 are entitled to notice of, and to vote at, the Meeting. Please read the accompanying Proxy Statement. Regardless of whether you plan to attend the Meeting, **please complete, sign and return promptly the Proxy Card,** so that a quorum will be present and a maximum number of shares may be voted. You may change your vote at any time by notifying the undersigned or by voting at the Meeting.

By Order of the Board of Trustees

Samuel A. Lieber, President

January 29, 2010

YOUR VOTE IS IMPORTANT. WHETHER OR NOT YOU PLAN TO ATTEND THE MEETING, PLEASE EITHER VOTE OVER THE INTERNET OR COMPLETE, DATE, SIGN AND MAIL THE PROXY CARD. YOUR PROMPT RESPONSE WILL ASSURE A QUORUM AT THE MEETING.

INSTRUCTIONS FOR SIGNING PROXY CARDS

The following general rules for signing proxy cards may be of assistance to you and avoid the time and expense to the Fund involved in validating your vote if you fail to sign your proxy card properly.

1. Individual Accounts: Sign your name exactly as it appears in the registration on the proxy card.

2. Joint Accounts: Either party may sign, but the name of the party signing should conform exactly to a name shown in the registration.

3. Other Accounts: The capacity of the individual signing the proxy card should be indicated unless it is reflected in the form of registration. For example:

		REGISTRATIONS	VALID SIGNATURES
Corporate Accounts			
	(1)	ABC Corp.	ABC Corp. (by John Doe, Treasurer)
	(2)	ABC Corp.	John Doe, Treasurer
	(3)	ABC Corp. c/o John Doe, Treasurer	John Doe
	(4)	ABC Corp. Profit Sharing Plan	John Doe, Trustee
Trust Accounts			
	(1)	ABC Trust	Jane B. Doe, Trustee
	(2)	Jane B. Doe, Trustee u/t/d/ 12/28/78	Jane B. Doe
Custodial or Estate Accounts			
	(1)	John B. Smith, Cust. f/b/o John B. Smith, Jr. UGMA	John B. Smith
	(2)	John B. Smith	John B. Smith, Jr., Executor

Alpine Global Dynamic Dividend Fund
c/o ALPS Fund Services, Inc.
1290 Broadway, Suite 1100
Denver, Colorado 80203

PROXY STATEMENT
January 29, 2010

This Proxy Statement is being furnished by the Board of Trustees (at times, the "Board") of the Alpine Global Dynamic Dividend Fund (the "Fund" or the "Trust"), to the shareholders of the Fund, in connection with the Fund's solicitation of shareholders' proxies for use at its Annual Meeting (the "Meeting") scheduled to be held March 18, 2010, at 11:00 a.m., Eastern Time, at 707 Westchester Avenue, White Plains, New York 10604 for the purposes set forth below and in the accompanying Notice of Annual Meeting. This Proxy Statement was mailed to registered shareholders only on or about January 29, 2010 and is available on the internet at www.proxyonline.com/docs/Alpineglobaldynamicdividendfund.pdf. The Notice of Internet Availability of Proxy Materials was mailed on or about January 29, 2010. At the Meeting, the shareholders of the Fund will be asked:

1. To elect Messrs. James A. Jacobson and H. Guy Leibler as Trustees to the Board of Trustees for a term of three years until their successor has been duly elected and qualified.

2. To transact such other business as may properly come before the Meeting or any adjournments thereof.

Record Date/Shareholders Entitled to Vote. The Fund is a closed-end management investment company registered under the Investment Company Act of 1940 (the "Investment Company Act"). The record holders of outstanding shares of the Fund are entitled to vote one vote per share (and a fractional vote per fractional share) on all matters presented at the Meeting. Shareholders of the Fund at the close of business on January 15, 2010 will be entitled to be present and vote at the Meeting. As of that date, there were 24,809,446 shares of the Fund outstanding and entitled to vote, representing total net assets of approximately $191,694,453.99.

Voting Proxies. Whether you expect to be personally present at the Meeting or not, we encourage you to vote by proxy. You can do this by completing, dating, signing and returning the proxy card. In addition, shareholders who received the Notice of Internet Availability of Proxy Materials (the "Notice") by mail, rather than the Proxy Statement, may vote over the internet using the control number found on the Notice. Properly executed proxies will be voted as you instruct by the persons named in the accompanying proxy statement. In the absence of such direction, however, the persons named in the accompanying proxy statement intend to vote "**FOR**" the election of Messrs. Jacobson and Leibler and may vote in their discretion with respect to other matters not now known to the Board that may be presented at the Meeting. Shareholders who execute proxies may revoke them at any time before they are voted, either by writing to the Secretary of the Trust, Andrew Pappert, c/o Alpine Woods Capital Investors, LLC, 2500 Westchester Avenue, Suite 215, Purchase, New York 10577, or in person at the time of the Meeting. If not so revoked, the shares represented by the proxy will be voted at the Meeting, and any adjournments thereof, as instructed. Attendance by a shareholder at the Meeting does not, in itself, revoke a proxy.

The election of a Trustee to the Board requires the affirmative vote of a plurality of the shares of beneficial interest entitled to vote for the election of any Trustee present in person or represented by proxy at a meeting with a quorum present. For purposes of the election of Trustees, abstentions and broker non-votes will be counted as shares present for quorum purposes, but will not be treated as votes cast. Abstentions and broker non-votes, therefore, will have no effect on the election of Messrs. Jacobson and Leibler as a Trustee. All properly executed proxies received prior to the Meeting will be voted at the Meeting in accordance with the instructions marked thereon. Proxies received prior to the Meeting on which no vote is indicated will be voted "FOR" the election of Messrs. Jacobson and Leibler as Trustees.

Quorum Required to Hold Meeting. In order to transact business at the Meeting, a "quorum" must be present. Under the Trust's Agreement and Declaration of Trust, a quorum is constituted by the presence in person or by proxy of shareholders representing a majority of the outstanding shares of the Fund on the record date entitled to vote on a matter.

Abstentions and broker non-votes (i.e., proxies from brokers or nominees indicating that they have not received instructions from the beneficial owners on an item for which the brokers or nominees do not have discretionary power to vote) will be treated as present for determining whether a quorum is present with respect to a particular matter. Abstentions and broker non-votes will not, however, be treated as votes cast at the Meeting. Abstentions and broker non-votes, therefore, will have no effect on proposals which require a plurality or majority of votes cast for approval, but will have the same effect as a vote "against" on proposals requiring any percentage of the outstanding voting securities of the Fund for approval.

If a quorum of shareholders of the Fund is not present at the Meeting, or if a quorum is present but sufficient votes to elect Messrs. Jacobson and Leibler as Trustees are not received, the shareholders present at the Meeting or the persons named as proxies shall have the power, but are under no obligation, to propose an adjournment of the Meeting without further notice other than announcement at the Meeting until such quorum shall be present. The shareholders entitled to cast not less than a majority of all the votes entitled to be cast at such meeting on a matter shall also have the power to adjourn the Meeting. Written notice of such an adjournment stating the place, date and hour thereof, and in the case of a special meeting, specifying the purpose or purposes thereof, shall be given to each shareholder entitled to vote thereat, at least (10) days prior to the meeting, if the Meeting is adjourned to a date more than one hundred thirty (130) days after the original Record Date set for the Meeting. With respect to the election of Messrs. Jacobson and Leibler as Trustees, the persons named as proxies will vote all proxies in favor of adjournment that voted in favor of the election, and vote against adjournment all proxies that voted against such election. Abstentions and broker non-votes will have the same effect at any adjourned meeting as noted above. Any business that might have been transacted at the Meeting may be transacted at any such adjourned session(s) at which a quorum is present.

Method and Cost of Proxy Solicitation. Proxies will be solicited by the Trust primarily via the internet or in some cases by mail. Although it is not anticipated, the solicitation may also include telephone, facsimile, electronic or oral communications by certain officers or employees of the Fund, Alpine Woods Capital Investors, LLC (the "Investment Adviser"), or ALPS Fund Services, Inc. ("ALPS"), the Fund's administrator, who will not be paid for these services. The Fund, the Investment Adviser or ALPS may also request broker-dealer firms, custodians, nominees and fiduciaries to forward proxy materials to the beneficial owners of the shares of the Fund held of record by such persons. If requested, the Fund shall reimburse such broker-dealer firms, custodians, nominees and fiduciaries for their reasonable expenses incurred in connection with such proxy solicitation, including reasonable expenses in communicating with persons for whom they hold shares of the Fund.

Delivery of Proxy to Security Holders Sharing an Address. Only one Notice or proxy statement is being delivered to multiple security holders sharing the same address. If requested, the Fund shall provide a proxy statement to each security holder sharing an address. Such security holders requesting individual proxy statements may call 1-800-617-7616 to place their request.

PROPOSAL

ELECTION OF TRUSTEES

Background. At the Meeting, shareholders will be asked to vote for the election of Messrs. Jacobson and Leibler, each to serve as Trustee for a term of three years or until his successor is duly elected and qualified.

The persons named as proxies on the proxy card enclosed with this Proxy Statement intend to vote at the Meeting "**FOR**" the election of Messrs. Jacobson and Leibler each to serve as a Trustee of the Trust for a term of three years until his successor has been duly elected and qualified.

Messrs. Jacobson and Leibler have consented to be named in this Proxy Statement and have agreed to serve if elected. If Messrs. Jacobson and Leibler should be unable to serve due to an event not now anticipated, the persons named as proxies will vote for such other nominee as may be proposed by the Nominating Committee of the Trust.

Information Concerning the Nominee/ Trustees. The following table sets forth information about Messrs. Jacobson and Leibler for election to the Board of Trustees and each currently-elected member of the Board of Trustees including, his name, address, age, position with the Trust, term of office and length of service with the Trust, principal occupation or employment and other directorships held during the past five years. Messrs. Jacobson and Leibler and each other independent trustee is not considered to be an "interested person" of the Fund within the meaning of the Investment Company Act or the Investment Adviser (each an "Independent Trustee" and , collectively, the "Independent Trustees"). Mr. Samuel A. Lieber is considered to be an "interested person" within the meaning of the Investment Company Act and the Investment Adviser.

NOMINEE/ TRUSTEES

Name, Address and Age	Position	Term of Office and Length of Time Served	Principal Occupation During the Past Five Years	Number of Portfolios in Fund Complex* Overseen by Trustee	Other Directorships Held by Trustee
James A. Jacobson (64), 2500 Westchester Ave, Suite 215 Purchase, NY 10577	Nominee and Independent Trustee	Until 2010, since July 21, 2009	Retired (11/2008-Present); Vice Chairman and Managing Director, Spear Leeds & Kellogg Specialists, LLC (01/2003-11/2008).	16	Trustee, each of the Alpine Trusts*; Trustee, Allianz Global Investors Multi-Funds.
H. Guy Leibler (55), 2500 Westchester Ave, Suite 215 Purchase, NY 10577	Nominee and Independent Trustee	Until 2010, since June 23, 2006.	Private investor since 2007, Vice Chair & Chief Operating Officer of L&L Acquisitions, LLC (2004-2007); President, Skidmore, Owings & Merrill LLP (2001-2004).	16	Chairman Emeritus, White Plains Hospital Center; Trustee, each of the Alpine Trusts.*

Name, Address and Age	Position	Term of Office and Length of Time Served	Principal Occupation During the Past Five Years	Number of Portfolios in Fund Complex* Overseen by Trustee	Other Directorships Held by Trustee
Jeffrey E. Wacksman (49) 2500 Westchester Ave, Suite 215 Purchase, NY 10577	Independent Trustee	Until 2011, since June 23, 2006.	Partner, Loeb, Block & Partners LLP since 1994.	16	Director, International Succession Planning Association; Trustee, Larchmont Manor Park Society; Director, Bondi Icebergs Inc. (Women's Sportswear); Director, MH Properties, Inc.; Trustee, each of the Alpine Trusts.*
Laurence B. Ashkin (81), 2500 Westchester Ave, Suite 215 Purchase, NY 10577	Independent Trustee	Until 2012, since June 23, 2006	Real estate developer and construction consultant since 1980; Founder and President of Centrum Properties, Inc. since 1980.	16	Director, Chicago Public Radio; Board Chair, The Perspectives Charter Schools; Trustee, each of the Alpine Trusts.*

Name, Address and Age	Position	Term of Office and Length of Time Served	Principal Occupation During the Past Five Years	Number of Portfolios in Fund Complex* Overseen by Trustee	Other Directorships Held by Trustee
Samuel A. Lieber** (53), 2500 Westchester Ave, Suite 215 Purchase, NY 10577	Interested Trustee, President and Chairman of the Board	Until 2012, since May 11, 2006.	Chief Executive Officer of Alpine Woods Capital Investors, LLC since November 1997. President of Alpine Trusts since 1998.	16	Trustee and Chairman of the Board, each of the Alpine Trusts.*

* The Fund Complex includes the Fund, each series of the Alpine Series Trust (Alpine Dynamic Balance Fund, Alpine Dynamic Dividend Fund, Alpine Dynamic Financial Services Fund, Alpine Dynamic Innovators Fund, Alpine Dynamic Transformations Fund and Alpine Accelerating Dividend Fund), each series of the Alpine Equity Trust (Alpine Cyclical Advantage Property Fund, Alpine International Real Estate Equity Fund, Alpine Realty Income & Growth Fund, Alpine Emerging Markets Real Estate Fund and Alpine Global Infrastructure Fund), each series of the Alpine Income Trust (Alpine Municipal Money Market Fund and Alpine Ultra Short Tax Optimized Income Fund) and the Alpine Total Dynamic Dividend Fund and the Alpine Global Premier Properties Fund.

** Mr. Lieber is the CEO of the Investment Adviser and is also the son of Stephen A. Lieber.

EXECUTIVE OFFICERS

The current executive officers of the Fund, in addition to Samuel A. Lieber, include the following:

Name, Address and Age	Position	Term of Office and Length of Time Served	Principal Occupation During the Past Five Years
Stephen A. Lieber (84) 2500 Westchester Ave, Suite 215 Purchase, NY 10577	Executive Vice President	Indefinite, since June 23, 2006.	Chief Investment Officer, Alpine Woods Capital Investors, LLC since 2003; Chairman and Senior Portfolio Manager, Saxon Woods Advisors, LLC since 1999.
John Megyesi (48) 2500 Westchester Ave, Suite 215 Purchase, NY 10577	Chief Compliance Officer	Indefinite, since March 30, 2009.	Chief Compliance Officer, Alpine Woods Capital Investors, LLC since January 2009; Vice President and Manager; Trade surveillance, Credit Suisse Asset Management, LLC (2006-2009); Manager, Trading and Surveillance, Allianz Global Investors (2004-2006).
Ronald Palmer (41) 2500 Westchester Ave, Suite 215 Purchase, NY 10577	Chief Financial Officer	Indefinite, since January 5, 2010	Independent Consultant (2008-2009); Vice President, Macquarie Capital Investment Management (2007-2008); Chief Operating Officer, Macquarie Fund Adviser, LLC (2004-2007).
Meimei Li (45) 2500 Westchester Ave, Suite 215 Purchase, NY 10577	Treasurer	Indefinite, since March 30, 2009	Controller, Alpine Woods Capital Investors, LLC since February 2007; Senior Accountant, Pinnacle Group (2005-2007); Senior Auditor, Eisner & Lubin LLP (2001-2005).
Andrew E. Pappert (29) 2500 Westchester Ave, Suite 215 Purchase, NY 10577	Secretary	Indefinite, since March 30, 2009	Director of Fund Operations, Alpine Woods Capital Investors, LLC since September 2008; Assistant Vice President, Mutual Fund Operations, Credit Suisse Asset Management, LLC (2003-2008).

Board Meetings and Committees. The Trust's Board held four regular meetings during the fiscal year ended October 31, 2009. The Board has also established three standing committees in connection with the governance of the Trust: an Audit Committee, a Nominating Committee, and a Valuation Committee. For the fiscal year ended October 31, 2009, Messrs. Jacobson and Leibler each attended at least 75% of the meetings of the Board and of the

Committees (if a member thereof) held during the period for which he was a Trustee.

Audit Committee. The Board has an Audit Committee consisting of all the Independent Trustees. In addition, the members of the Audit Committee are also "independent," as defined in the Fund's written Charter for the Audit Committee. The members of the Audit Committee include H. Guy Leibler, Jeffrey E. Wacksman, Laurence B. Ashkin and James A. Jacobson. As of January 5, 2010, Mr. Leibler serves as the Chairman of the Audit Committee. Mr. Ashkin continues to serve as the Audit Committee Financial Expert. The Audit Committee is responsible for advising the full Board regarding accounting, auditing and financial matters affecting the Trust. The Audit Committee met four times during the fiscal year ended October 31, 2009. The Board has adopted a written Charter for the Audit Committee, which is available at the Fund's website, www.alpinecef.com.

Nominating Committee. The Board has a Nominating Committee consisting of all the Independent Trustees. The members of the Nominating Committee include H. Guy Leibler, Jeffrey E. Wacksman, Laurence B. Ashkin and James A. Jacobson. Mr. Leibler serves as the Chairman of the Nominating Committee. The Nominating Committee is responsible for seeking and reviewing candidates for consideration as nominees for Trustees as is considered necessary from time to time. The Nominating Committee met four times during the fiscal year ended October 31, 2009. The Board has adopted a written Charter for the Nominating Committee, which is available at the Fund's website, www.alpinecef.com.

The Nominating Committee will review shareholders' nominations to fill vacancies on the Board. Recommendations for consideration by the Nominating Committee should be sent to the Chairman of the Nominating Committee in writing together with the appropriate biographical information concerning each such proposed nominee, and such recommendation must comply with the notice provisions set forth in the Trust By-Laws. In general, to comply with such procedures, such nominations, together with all required biographical information, must be delivered to and received by the Chairman of the Nominating Committee at the principal executive offices of the Trust not later than 60 days prior to the shareholder meeting at which any such nominee would be voted on.

In identifying and evaluating nominees for Trustee, the Nominating Committee seeks to ensure that the Board of Trustees possess, in the aggregate, the strategic, managerial and financial skills and experience necessary to fulfill its duties and to achieve its objectives, and also seeks to ensure that the Board of Trustees is comprised of trustees who have broad and diverse backgrounds. The Nominating Committee looks at each nominee on a case-by-case basis. In looking at the qualification of each candidate to determine if their election would further the goals described above, the Nominating Committee takes into account all factors it considers appropriate, which may include strength of character, mature judgment, career specialization, relevant technical skills or financial acumen, diversity of viewpoint and industry knowledge. However, the Board of Trustees believes that to be recommended as a nominee, whether by the Nominating Committee or at the suggestion of a shareholder, each candidate must: (1) display the highest personal and professional ethics, integrity and values; (2) have the ability to exercise sound business judgment; (3) be highly accomplished in his or her respective field; (4) have a relevant expertise and experience; (5) be able to represent all shareholders and be committed to enhancing long-term shareholder value; and (6) have sufficient time available to devote to activities of the Board of Trustees and enhance his or her knowledge of the Trust's business.

Valuation Committee. The Board has a Valuation Committee consisting of all the Independent Trustees. The members of the Valuation Committee include H. Guy Leibler, Jeffrey E. Wacksman, Laurence B. Ashkin and James A. Jacobson. Mr. Wacksman serves as Chairman of the Valuation Committee. The Valuation Committee is responsible for (1) monitoring the valuation of portfolio securities and other investments; and (2) as required by the Trust's valuation policies, when the full Board of Trustees is not in session, determining the fair value of illiquid and other holdings after consideration of all relevant factors, which determinations are reported to the Board of Trustees. The Valuation Committee met three times during the fiscal year ended October 31, 2009. The Board has adopted a written Charter for the Valuation Committee, which is available at the Fund's website, www.alpinecef.com. The Fund does not have a compensation committee.

Communication to the Trustees. Shareholders may contact the Trustees directly by contacting the Secretary of the Trust at the principal executive offices of the Trust with such request. Such correspondences should be sent to Andrew Pappert, Secretary, c/o Alpine Woods Capital Investors, LLC, 2500 Westchester Avenue, Suite 215, Purchase, New York 10577.

Compensation of Trustees. Under the federal securities laws, the Fund is required to provide to its shareholders in connection with the Meeting information regarding compensation paid to Trustees by the Fund as well as by the various other U.S. registered investment companies advised by the Investment Adviser during its prior fiscal year.

The table below sets forth the amount of compensation the Trustees received from the Fund during the fiscal year ended October 31, 2009. Currently, the Fund does not have a bonus, profit sharing, pension or retirement plan.

Name of Trustee	Aggregate Compensation from the Fund	Total Compensation from Fund and Fund Complex Paid to Trustee
Jeffrey E. Wacksman	$ 16,000	$ 60,000
Laurence B. Ashkin	$ 16,000	$ 60,000
H. Guy Leibler	$ 16,000	$ 60,000
James A. Jacobson	$ 8,000	$ 27,000
Samuel A. Lieber	$ 0	$ 0

Management Ownership. To the knowledge of the Fund's management, before the close of business on January 15, 2010, the officers and Trustees of the Trust owned, as a group, less than 1% of the outstanding shares of the Fund. The following table sets forth the aggregate dollar range of equity securities beneficially owned of the Fund and of all Funds overseen by each Trustee in the Fund Complex as of December 31, 2009:

Amount Invested Key

A. None

B. $1-$10,000

C. $10,001-$50,000

D. $50,001-$100,000

E. over $100,000

Name of Trustee	Dollar Range of Fund Shares Owned	Aggregate Dollar Range of Equity Securities in all Funds Overseen by Trustees in Fund Complex*
Independent Trustees		
Jeffrey E. Wacksman	C	E
Laurence B. Ashkin	D	E
H. Guy Leibler	C	D
James A. Jacobson	A	A
Interested Trustee		
Samuel A. Lieber	C	E

* The Fund Complex includes the Fund, each series of the Alpine Series Trust (Alpine Dynamic Balance Fund, Alpine Dynamic Dividend Fund,

Alpine Dynamic Financial Services Fund, Alpine Dynamic Innovators Fund, Alpine Dynamic Transformations Fund, and Alpine Accelerating Dividend Fund), each series of the Alpine Equity Trust (Alpine Cyclical Advantage Property Fund, Alpine International Real Estate Equity Fund, Alpine Realty Income & Growth Fund, Alpine Emerging Markets Real Estate Fund and Alpine Global Infrastructure Fund), each series of the Alpine Income Trust (Alpine Municipal Money Market Fund and Alpine Ultra Short Tax Optimized Income Fund) and the Alpine Total Dynamic Dividend Fund and the Alpine Global Premier Properties Fund.

Trustee Transactions with Fund Affiliates. As of January 15, 2010, neither the Independent Trustees nor members of their immediate family owned securities beneficially or of record in the Investment Adviser, or an affiliate of or any person directly or indirectly controlling, controlled by or under common control with the Investment Adviser. Furthermore, over the past five years, neither the Independent Trustees nor members of their immediate family have any direct or indirect interest, the value of which exceeds $120,000, in the Investment Adviser or any of its affiliates. In addition, since the beginning of the last two fiscal years, neither the Independent Trustees nor members of their immediate family have conducted any transactions (or series of transactions) or maintained any direct or indirect relationship in which the amount involved exceeds $120,000 and to which the Investment Adviser or any affiliate thereof was a party.

Required Vote. The election of a Trustee to the Board of Trustees requires the affirmative vote of a plurality of the shares of beneficial interests entitled to vote for the election any Trustee, represented in person or by proxy at a meeting of the shareholders with a quorum present. For purposes of the election of Messrs. Jacobson and Leibler, abstentions and broker non-votes will be treated as votes present at the Meeting, but will not be treated as votes cast. Abstentions and broker non-votes, therefore, will have no effect on the election of Messrs. Jacobson and Leibler as Trustees.

THE BOARD OF TRUSTEES, INCLUDING THE INDEPENDENT TRUSTEES, RECOMMENDS THAT YOU VOTE "FOR" THE ELECTION OF MESSRS. JAMES A. JACOBSON AND H. GUY LEIBLER TO THE BOARD OF TRUSTEES. ANY SIGNED BUT UNMARKED PROXIES WILL BE SO VOTED "FOR" APPROVAL OF THIS PROPOSAL.

INFORMATION ABOUT THE FUND

The Fund's current Investment Adviser is Alpine Woods Capital Investors, LLC, 2500 Westchester Avenue, Suite 215, Purchase New York 10577. The Fund's administrator is ALPS Fund Services, Inc., 1290 Broadway, Suite 1100, Denver, Colorado 80203. The Fund's transfer and dividend disbursing agent is The Bank of New York Mellon, One Wall Street, New York, New York 10286. The Bank of New York Mellon also serves as the Fund's Custodian for the Fund's securities and cash and is located at 101 Barclay Street, New York, New York 10286.

Independent Registered Public Accounting Firm. Deloitte & Touche LLP ("Deloitte"), 555 East Wells Street, Milwaukee, Wisconsin, 53202 currently serves as the independent registered public accountant for the Trust. Representatives of Deloitte are not expected to attend the Meeting but have been given the opportunity to make a statement if they so desire and will be available should any matter arise requiring their presence.

The Trust has engaged Deloitte to perform audit services, audit-related services, tax services and other services for the current fiscal year. "Audit services" refer to performing an audit of the Trust's annual financial statements or services that are normally provided by the accountant in connection with statutory and regulatory filings or engagements for those fiscal years. "Audit-related services" refer to the assurance and related services by the principal accountant that are reasonably related to the performance of the audit. "Tax services" refer to professional services rendered by the principal accountant for tax compliance, tax advice, and tax planning. The following table details the aggregate fees billed for the fiscal year ended October 31, 2009 for audit fees, audit-related fees, tax fees and other fees by Deloitte:

	Aggregate Total for Fiscal Year Ended 10/31/09	
Audit Fees	$	28,400
Audit-Related Fees	$	0
Tax Fees	$	4,615
All Other Fees	$	0

The Fund's Audit Committee adopted pre-approval policies and procedures that require the Audit Committee to pre-approve all audit and non-audit services of the Trust, including services provided to any entity affiliated with the Trust. All of Deloitte's hours spent on auditing the Trust's financial statements were attributed to work performed by full-time permanent employees of Deloitte.

Since inception, and for the past two fiscal years, Deloitte has not billed the Trust or the Investment Adviser (or any entity controlling, controlled by or under common control with the Investment Adviser) for, nor accrued for on behalf of the Trust or the Investment Adviser, any non-audit fees other than certain tax fees. The Audit Committee of the Board of Trustees has considered whether the provision of non-audit services that were rendered to the Investment Adviser or any entity controlling, controlled by or under common control with the Investment Adviser, is compatible with maintaining Deloitte's independence, and has concluded that the provision of such non-audit services by Deloitte has not compromised its independence.

Audit Committee Report. The Audit Committee has met and held discussions with Deloitte, the Fund's independent registered public accountant. The independent registered public accountant represented to the Audit Committee that the Fund's financial statements were prepared in accordance with U.S. generally accepted accounting principles. The Audit Committee (i) reviewed and discussed with management the Fund's audited financial statements for the most recently completed fiscal year; (ii) discussed with the Fund's independent registered public accountant, the matters required to be discussed by Statement on Auditing Standards No. 61; and (iii) obtained from Deloitte a formal written statement consistent with Independence Standards Board Standard No. 1, "Independence Discussions with Audit Committees," describing all relationships between Deloitte and the Fund that might bear on Deloitte's independence and discussed with Deloitte any relationships that may impact Deloitte's objectivity and independence and satisfied itself as to Deloitte's independence.

Based upon the Audit Committee's discussion with Deloitte and the Audit Committee's review of the representations of Deloitte and the report of Deloitte to the Audit Committee, the Audit Committee recommended that the Board of Trustees include the audited financial statements in the Fund's Annual Report for the fiscal year ended October 31, 2009 filed with the SEC.

Section 16(a) Beneficial Ownership Reporting Compliance. Section 16(a) of the Securities Exchange Act of 1934 (the "Exchange Act") and Section 30(h) of the Investment Company Act in combination require the Fund's directors and officers, persons who own more than ten (10%) of the Fund's common shares, and the Fund's Investment Adviser and its directors and officers, to file reports of ownership and changes in ownership with the SEC. Based solely on a review of the reports filed with the SEC, the Fund believes that during fiscal year ended October 31, 2009, all Section 16(a) filing requirements applicable to Fund officers, Trustees and greater than 10% beneficial owners were complied with except in one instance. The initial statement of beneficial ownership of securities on Form 3 of Mr. James A. Jacobson, Trustee, was not filed within ten days after the event by which Mr. Jacobson became a reporting person. The initial statement of beneficial ownership of securities of Mr. Jacobson has since been filed with the SEC. Mr. Jacobson has no beneficial ownership of securities in the Fund.

Information Pertaining to Certain Stockholders. To the knowledge of the Fund's management, before the close of business on January 15, 2010, the following tables sets forth the beneficial ownership of shares of the Fund by each person known to the Fund to be deemed the beneficial owner of more than five (5%) percent of the outstanding shares of the Fund:

5% or Greater Shareholders*

Name and Address	Number of Shares	Percentage Ownership	Type of Ownership
First Clearing LLC 10700 Wheat First Dr. WS 1023 Glen Allen, VA 23060	5,829,170	23.51%	Beneficial
National Financial Services LLC 200 Liberty Street New York, NY 10281	2,849,605	11.49%	Beneficial
Citigroup Global Markets 111 Wall Street New York, NY 10005	1,908,133	7.70%	Beneficial
Charles Schwab 211 Main St. San Francisco, CA 94105	1,639,509	6.61%	Beneficial

* To the knowledge of the Fund's management, before the close of business on January 15, 2010, the officers and Trustees of the Trust owned, as a group, less than 1% of the outstanding shares of the Fund.

Recent Board Approvals Affecting the Fund. The Board of Trustees recently approved, effective immediately, that the Fund may invest up to 35% of its total assets in investments in countries that are considered emerging markets (previously, no such limitation had been established). The Fund will rely upon the MSCI Emerging Markets Index in its determination of which countries are considered emerging markets. The Board also approved, effective immediately, that the Fund may now borrow for investment purposes. The Adviser currently intends to limit leverage to 10% of the Fund's total assets (calculated at the time of borrowing) and borrow for investment purposes only when the Adviser believes that the potential return on additional investments acquired with the proceeds of leverage is likely to exceed the costs incurred in connection with the borrowings. If leverage is used, it creates three major types of risks for shareholders: (1) the likelihood of greater volatility of net asset value and market price of the shares; (2)the possibility that income will decline if the interest rate on any borrowings rises or that income and distributions will fluctuate because the interest rate on any borrowings varies; and (3) the Fund may not be permitted to declare dividends or other distributions or purchase its capital stock, unless at the time thereof the Fund meets certain asset coverage requirements.

The Fund is required by federal law to file reports, proxy statements and other information with the SEC. The SEC maintains a website that contains information about the Fund (www.sec.gov). Any such proxy material, reports and other information can be inspected and copied, after paying a duplicating fee, at the Office of Public Reference, Securities and Exchange Commission, 100 F Street, N.E., Washington, D.C. 20549-0102.

Reports to Shareholders. THE MOST RECENT ANNUAL REPORT OF THE FUND, INCLUDING FINANCIAL STATEMENTS, HAS BEEN PREVIOUSLY MAILED TO SHAREHOLDERS. IF YOU HAVE NOT RECEIVED THIS REPORT OR WOULD LIKE TO RECEIVE AN ADDITIONAL COPY FREE OF CHARGE, PLEASE CONTACT ALPS FUND SERVICES, INC., 1290 BROADWAY, SUITE 1100, DENVER, CO 80203, OR 1-800-617-7616, AND IT WILL BE SENT PROMPTLY BY FIRST-CLASS MAIL. THESE REPORTS ARE ALSO AVAILABLE ON THE SEC'S WEBSITE, WWW.SEC.GOV AND AT WWW.ALPINECEF.COM.

GENERAL INFORMATION

Other Matters to Come Before the Meeting.

(Dollars in thousands)

Underlying Properties(1)

34,653

0

34,653

$

382,226

$

154,236

Net Profits Interests:

Royalty NPI

11,266

0

11,266

$

141,923

$

59,278

Term NPI

5,997
0
5,997
75,540
54,992
Total

17,263

0

17,263

$

217,463

$

114,270

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(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 (the Commission) and the 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.

COMPETITION AND MARKETS

All of the production attributable to the Net Profits Interest is sold to Eastern Marketing pursuant to the Gas Purchase Contract. See The Net Profits Interests - Gas Purchase Contract.

REGULATION OF NATURAL GAS

The natural gas industry has historically been highly regulated by state and federal authorities. In the past, concerns about perceived pipeline monopolies and other factors caused Congress to impose economic regulation on both pipelines and producers. Federal agencies regulated tariffs and conditions of service offered by interstate pipelines, and set maximum prices on the wellhead price of natural gas sold into interstate commerce. States, and even local governments, also regulated retail sales of natural gas by local utilities. Government agencies also set production rates to avoid waste and imposed environmental and safety regulations. At present, it appears that Federal regulation of wellhead natural gas prices has ended. However, there can be no assurance that price controls or other similar economic regulations may not be reimposed in the future.

Drilling and production of natural gas are heavily regulated in Pennsylvania and West Virginia, as in most states. A well cannot be drilled without a permit, and operations must be conducted in compliance with environmental, safety and conservation laws and regulations. In contrast to many other states which have substantial oil and gas production activity, the spacing of shallow wells (such as the wells subject to the Net Profits Interests) is not regulated by any state statute or regulatory agency in either West Virginia or Pennsylvania. Without spacing requirements specified by state statute or regulation, drainage of reserves from a property may occur from wells located in close proximity to such property.

HEALTH, SAFETY, AND ENVIRONMENTAL REGULATION

General. Activities on the Underlying Properties are subject to existing Federal, state and local laws and regulations governing health, safety, environmental quality and pollution control. It is anticipated that, absent the occurrence of an extraordinary event, compliance with existing Federal, state and local laws, rules and regulations regulating health, safety, the discharge of materials into the environment or otherwise relating to the protection of the environment will not have a material adverse effect upon the Trust. It cannot be predicted what effect additional regulation or legislation, enforcement policies thereunder, and claims for damages to property, employees, other persons and the environment resulting from operations on the Underlying Properties could have on the Trust. However, pursuant to the terms of the Conveyances, any costs or expenses incurred in connection with environmental liabilities of Eastern American arising out of or related to activities occurring on or in, or conditions existing on or under, the Underlying Properties before the effective date of the Conveyances will be borne by Eastern American and will not be deducted in calculating Net Proceeds attributable to the Net Profits Interests. Additionally, because Unitholders will have limited liability in accordance with the Trust Agreement and Delaware law, Unitholders should be shielded from direct liability for any environmental liabilities. See Description of Trust Units and Depositary Units Liability of Unitholders. However, costs and expenses incurred by Eastern American for certain Capital Costs associated with environmental liabilities arising after the effective date of the Conveyances would reduce Net Proceeds, and would therefore be borne, in part, by the Unitholders. The following subtopics discuss some of the principal forms of health, safety, and environmental regulation to which the Underlying Properties and operations thereon are subject. The costs of complying with these regulatory requirements may burden the Net Profits Interests to the extent they arise out of or are related to activities occurring on or in, or conditions existing on or under, the Underlying Properties after the effective date of the Conveyances.

Solid and Hazardous Waste. The Underlying Properties include numerous properties that have produced gas for a number of years but in which Eastern American has held an interest for a relatively short period of time prior to the effective date of the Conveyances. Eastern American has informed us they have no knowledge of prior operators utilizing operating and disposal practices that were not standard in the industry at the time nor have hydrocarbons or other solid or hazardous wastes may have been disposed of or released on or under the Underlying Properties. Federal, state and local laws applicable to gas-related wastes have become increasingly more stringent. Under current laws, Eastern American or the operator of the Underlying Properties could be required to remove or remediate previously disposed wastes or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

The operations of the Underlying Properties may generate wastes that are subject to the Federal Resource Conservation and Recovery Act (RCRA) and comparable state statutes. The Environmental Protection Agency (the EPA) has limited the disposal options for certain hazardous wastes and may adopt more stringent disposal standards for nonhazardous wastes.

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the superfund law, imposes liability, regardless of fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include the current or previous owner and operator of a site and companies that disposed or arranged for the disposal of, the hazardous substance found at a site. CERCLA also authorizes the EPA and, in some cases, private parties to take actions in response to threats to the public health or the environment and to seek recovery from such responsible classes of persons of the costs of such action. In the course of their operations, the operators of the Underlying Properties have generated and will generate wastes that may fall within CERCLA s definition of hazardous substances . Eastern American or the previous operator of the Underlying Properties may be responsible under CERCLA for all or part of the costs to clean up sites at which such substances have been disposed.

Air Emissions. The operations of the Underlying Properties are subject to Federal, state and local regulations concerning the control of emissions from sources of air contaminants. Administrative enforcement actions for failure to comply strictly with air regulations or permits are generally resolved by payment of a monetary penalty and correction of any identified deficiencies. Regulatory agencies could require the operators to forego or modify construction or operation of certain air emission sources.

OSHA. The operations of the Underlying Properties are subject to the requirements of the Federal Occupational Safety and Health Act (OSHA) and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the Federal Superfund Amendment and Reauthorization Act and similar state statutes require that information be organized and maintained about hazardous materials used or produced in the operations. Certain of this information must be provided to employees, state and local government authorities and citizens.

DESCRIPTION OF TRUST UNITS AND DEPOSITARY UNITS

The following information is subject to the detailed provisions of the Deposit Agreement originally entered into by Eastern American, the Trustee, and Bank of Montreal Trust Company, as Depositary (the Depositary) and all holders from time to time of Depositary Units (the Deposit Agreement), a copy of which is filed as an exhibit to this Form 10-K.

The functions of the Depositary under the Deposit Agreement are custodial and ministerial in nature and for the benefit of Unitholders. The Deposit Agreement and the issuance of Depositary Units thereunder provide Unitholders an administratively convenient form of holding an investment in the Trust and a Treasury Obligation. Each Depositary Unit is evidenced by a certificate, which is issued by the Depositary and transferable only in denominations of 50 Depositary Units or an integral multiple thereof. Accordingly, each holder of 50 Depositary Units owns a beneficial interest in 50 Trust Units and the entire beneficial interest in a discrete Treasury Obligation in a face amount of $1,000, or $20 per Depositary Unit.

The deposited Trust Units and Treasury Obligations are held solely for the benefit of the Unitholders and do not constitute assets of the Depositary or the Trust. The Depositary has no power to assign, transfer, pledge or otherwise dispose of any of the Trust Units or Treasury Obligations, except in the limited instances provided in the Deposit Agreement.

Generally, the holders of Depositary Units are entitled to participate in distributions with respect to the Trust Units, the Treasury Obligations and to the liquidation of the remaining assets of the Trust.

Withdrawal of Trust Units and Restrictions on Transfer

Upon presentation of Depositary Units in denominations of 50 or integral multiples thereof for withdrawal of the Trust Units and discrete Treasury Obligations evidenced thereby in accordance with the Deposit Agreement, the Unitholder will receive an uncertificated direct interest in Trust Units. These withdrawn Trust Units will be evidenced on the books of the Trustee by a transfer of such Trust Units from the name of the Depositary to the name of the withdrawing Unitholder. Holders of withdrawn Trust Units will be entitled to receive Trust distributions and periodic Trust information (including tax information) directly from the Trustee. Moreover, holders of Trust Units will be entitled to each of the rights accorded Unitholders under the Trust Agreement, including voting and liquidation rights, as elsewhere described herein, except that withdrawn Trust Units are not freely transferable as described below.

Pursuant to the Trust Agreement and the transfer application for transfer of the Trust Units, withdrawn Trust Units are not transferable except by operation of law. A holder of withdrawn Trust Units may, however, transfer such Trust Units in denominations of 50 (or integral multiples thereof) to the Depositary for redeposit, together with Treasury Obligations in the face amount equal to $1,000 for each 50 Trust Units redeposited, in exchange for Depositary Units. Such redeposit may be effected by delivering written notice of such transfer jointly to the Depositary and the Trustee together with proper documentation necessary to transfer the requisite Treasury Obligations into the name of the Depositary.

Distributions and Income Computations

The Trustee determines for each quarter the Quarterly Distribution Amount available for distribution to holders of Depositary Units and the Trust Units evidenced thereby. The Quarterly Distribution Amount is equal to the excess, if any, (i) the cash that the Trust receives on or before the tenth day of the third month after the end of each calendar quarter ending before the Trust is dissolved and that is attributable to production from the Net Profits Interest held by the Trust during that calendar quarter, plus, with certain exceptions, any other cash receipts of the Trust during such quarter, over (ii) the liabilities for the Trust paid during such quarter, subject to adjustments for changes made by the Trustee during such quarter in any cash reserves established for the payment of contingent or future obligations of the Trust. Based on the payment procedures relating to the Net Profits Interests, cash received by the Trustee in a particular quarter from the Net Profits Interests reflects actual gas production for a portion of such quarter and a production estimate for the remainder of such quarter, such estimate to be adjusted to actual production in the following quarter. The Quarterly Distribution Amount for each quarter is payable to Unitholders of record on the Quarterly Record Date, which is the last day of the second month following the end of such calendar quarter or such later date as the Trustee determines is required to comply with legal or stock exchange requirements. The Trustee generally is able to distribute cash on or before the 15th day (or the next succeeding business day following such day if such day is not a business day) of the third month following the end of each calendar quarter to each person who was a Unitholder of record on the Quarterly Record Date, together with interest earned on such Quarterly Distribution Amount from the date of receipt thereof by the Trustee to the payment date.

The net taxable income of the Trust for each calendar quarter is reported by the Trustee for tax purposes as belonging to the holders of record to whom the Quarterly Distribution Amount was or will be distributed. Assuming that the Trust will be classified for tax purposes as a grantor trust, the net taxable income will be realized by the holders for tax purposes in the calendar quarter received by the Trustee, rather than in the quarter distributed by the Trustee. Taxable income of a holder may differ from the Quarterly Distribution Amount because the Treasury Obligations will be treated as generating interest income for tax purposes. There may also be minor variances because of the possibility that, for example, a reserve will be established in one quarter that will not give rise to a tax deduction until a subsequent quarter, an expenditure paid for in one quarter will have to be amortized for tax purposes over several quarters. See Federal Income Tax Matters .

Each holder of Depositary Units (including the underlying Trust Units) of record as of the record date for the final quarter of the Trust s existence will be entitled to receive a liquidating distribution equal to a pro rata portion of the net proceeds from the sale of the Royalty NPI (to the extent not previously distributed) and a pro rata portion of the proceeds from the matured Treasury Obligations.

Possible Divestiture of Depositary Units and Trust Units

The Trust Agreement imposes no restrictions based on nationality or other status of holders of Trust Units. However, the Trust Agreement and the Deposit Agreement provide that in the event of certain judicial or administrative proceedings seeking the cancellation or forfeiture of any property in which the Trust has an interest because of the nationality, citizenship, or any other status, of any one or more holders of Trust Units including holders of Depositary Units, the Trustee will give written notice thereof to each holder whose nationality, citizenship or other status is an issue in the proceeding, which notice will constitute a demand that such holder dispose of his Depositary Units or withdrawn Trust Units within 30 days. If any holder fails to dispose of his Depositary Units or withdrawn Trust Units in accordance with such notice, cash distributions on such units are subject to suspension. In the event a holder fails to dispose of Depositary Units in accordance with such notice, the Depositary may cancel such holder s Depositary Units and reissue them in the name of the Trustee, whereupon the Trustee will use its reasonable efforts to sell the Depositary Units and remit the net sale proceeds to such holder. In the case of Trust Units withdrawn from deposit with the Depositary, the Trustee shall redeem such Trust Units not divested in accordance with such notice, for a cash price equal to the then-current market price of the Depositary Units less the then-current over-the-counter bid price of the related, withdrawn Treasury Obligations. The redemption price will be paid out in quarterly installments limited to the amount that otherwise would have been distributed in respect of such redeemed Trust Units.

Liability of Unitholders

Consistent with Delaware law, the Trust Agreement provides that the Unitholders will have the same limitation on liability as is accorded under the laws of such state to stockholders of a corporation for profit. No assurance can be given, however, that a court would give effect to such limitation.

Liquidation of the Trust

The Trust will be liquidated and the Royalty NPI will be sold prior to the Liquidation Date, which is expected to occur in 2013. Unitholders of record as of the record date for the final quarter of the Trust s existence will be entitled to receive a terminating distribution with respect to each Depositary Unit equal to a pro rata portion of the net proceeds from the sale of the Royalty NPI (to the extent not previously distributed) and a pro rata portion of the proceeds from the matured Treasury Obligations. Under the Trust Agreement, Eastern American has a right of first refusal to purchase the Royalty NPI at fair market value, or if applicable the offered third-party price, prior to the Liquidation Date.

FEDERAL INCOME TAX MATTERS

This section is a summary of Federal income tax matters of general application which addresses the material tax consequences of the ownership and sale of Depositary Units. This section provides a generalized summary of certain federal income tax matters of general application relating to ownership and sale of Depositary units by individuals who are citizens or residents of the United States. Accordingly, the following discussion has only limited application to domestic corporations and persons subject to specialized Federal income tax treatment, such as tax-exempt entities (including IRAs), regulated investment companies and insurance companies. The following discussion also does not address tax consequences to foreign persons. It is impractical to comment on all aspects of Federal laws that may affect the tax consequences of the transactions contemplated hereby and of an investment in Depositary Units as they relate to the particular circumstances of every prospective Unitholder. Each Unitholder should consult his own tax advisor with respect to his particular circumstances including, his alternative minimum tax circumstances.

This summary is based on current provisions of the Internal Revenue Code of 1986, as amended (the Code), existing and proposed regulations thereunder and current administrative rulings and court decisions, all of which are subject to changes that may or may not be retroactively applied. Some of the applicable provisions of the Code have not been interpreted by the courts or the Internal Revenue Service (IRS).

At the issuance of the Depositary Units, Eastern American obtained an opinion of counsel for the benefit of the Trust, based on certain representations and subject to certain qualifications, that, for Federal income tax purposes, (a) the Trust will be taxed as a grantor trust and not as an association taxable as a corporation, (b) the Term NPI will be taxed as a production payment, (c) the income from the Royalty NPI will be royalty income subject to the allowance for depletion, and (d) a Unitholder will be eligible to claim Section 29 Credits with respect to certain sales of gas production attributable to the Royalty NPI. The Trustee has reported the operations of the Trust consistent with these opinions.

No ruling has been or will be requested from the IRS with respect to any matter affecting the Trust or Unitholders, and thus no assurance can be provided that the statements set forth herein (which do not bind the IRS or the courts) will not be challenged by the IRS or will be sustained by a court if so challenged.

Reports

Unitholders of record are provided informational tax packages in order to permit computation of their taxable income from ownership of Depositary Units.

Treatment of Depositary Units

Purchasers of Depositary Units are treated, for Federal income tax purposes, as purchasing directly an interest in the Treasury Obligations and a Trust Unit. Purchasers are therefore required to allocate the purchase price of their Depositary Unit between the interest in the Treasury Obligations and the Trust Unit in the proportion that the fair market value of each bears to the fair market value of the Depositary Unit. Information regarding purchase price allocations is furnished to Unitholders by the Trustee.

Classification and Taxation of the Trust

For federal income tax purposes, the Trust has been treated and expects to continue to be treated not as an association taxable as a corporation, but as a grantor trust that is not subject to Federal income tax as an entity separate from its beneficial owners. For tax purposes, Unitholders are considered to own and receive the Trust s assets and income as though no trust were in existence. The Trust files an information return, reporting all items of income, credit or deduction which must be included in the tax returns of the Unitholders. If the Trust were determined not to be a grantor trust, it is expected that it would be treated either as a partnership subject to the publicly traded partnership rules under the Code or as an association taxable as a corporation. If the Trust were treated as a publicly traded partnership, it is believed that the Trust s various items of income and deduction would still be taxable to the Unitholders on a current, flow-through basis as partners of a partnership and not to the Trust as an association taxable as a corporation. If the Trust were determined to be an association taxable as a corporation, it would be treated as a separate entity subject to corporate tax on its taxable income, Unitholders would be treated as shareholders, and distributions to Unitholders from the Trust would be treated as nondeductible corporate distributions. Such distributions would be taxable to a Unitholder, first, as dividends to the extent of the Unitholder s pro rata share of the Trust s earnings and profits, then as a tax-free return of capital to the extent of his basis in his Trust Units, and finally as capital gain to the extent of any excess.

Direct Taxation of Unitholders

Assuming that the Trust is treated as a grantor trust for Federal income tax purposes, and Unitholders are treated for Federal income tax purposes as owning a direct interest in the Treasury Obligations and the assets of the Trust, each Unitholder is taxed directly on his pro rata share of the income attributable to the Treasury Obligations and the assets of the Trust and is entitled to claim his pro rata share of the deductions and credits attributable to the Trust (subject to certain limitations discussed below). Income, credits and expenses attributable to the assets of the Trust and the Treasury Obligations are taken into account by Unitholders consistent with their method of accounting and without regard to the taxable year or accounting method employed by the Trust.

The Trust makes quarterly distributions to Unitholders of record on each Quarterly Record Date. The terms of the Trust Agreement, as described below, seek to assure to the extent practicable that taxable income attributable to such distributions will be reported by the Unitholder who receives such distribution, assuming that he is the owner of record on the Quarterly Record Date. In certain circumstances, however, a Unitholder will not receive the distribution attributable to such income. For example, if the Trustee establishes a reserve or borrows money to satisfy liabilities of the Trust, income associated with the cash used to establish that reserve or to repay that loan must be reported by the Unitholder, even though that cash is not distributed to him. In addition, Unitholders must recognize certain interest income attributable to the Treasury Obligations with respect to which no current cash distributions will be made.

The Trust allocates income, deductions and credits to Unitholders based on record ownership at Quarterly Record Dates. The IRS could require income and deductions of the Trust to be determined and allocated daily or require some method of daily proration, which could result in an increase in the administrative expenses of the Trust.

Under current market conditions, it is anticipated that total distributable cash will exceed taxable income through 2005. After 2005, taxable income is anticipated to exceed distributable cash, and the amount of such excess could be significant. Such estimates are based on numerous assumptions as to the allocation of a Unitholder s purchase price and the amount and treatment of operating costs, development costs, Trust administrative expenses, production estimates and depletion. No assurance can be given that the estimates will prove to be correct, and the actual relationship between distributable cash and taxable income could be materially different.

Treatment of Trust Units

On the assumption that the Trust is a grantor trust for Federal income tax purposes, each Unitholder is treated as purchasing directly an interest in the Net Profits Interests. Purchasers of Depositary Units must allocate the portion of their total purchase price allocated to the Trust Unit between the Royalty NPI and the Term NPI in the proportion that the fair market value of each bears to the total fair market value of both. Information regarding purchase price allocations is furnished to Unitholders by the Trustee.

Interest Income

The Term NPI is treated as a production payment under Section 636(a) of the Code. Thus, Unitholders are treated as making a mortgage loan on the Underlying Properties of the Term NPI to Eastern American in an amount equal to the amount of the purchase price of each Depositary Unit allocated to the Term NPI. Because it is treated as a debt instrument for tax purposes, the Term NPI is subject to the original issue discount income (OID) rules of the Code which generally require the periodic inclusion of the original issue discount in income of the purchaser of a debt instrument. The Code also authorizes the IRS to prescribe regulations modifying the statutory provisions where, by reason of contingent payments such as those provided for by the Term NPI, the tax treatment provided under the Code provisions does not carry out the purposes of such provisions.

The IRS has issued a series of proposed and final regulations dealing with debt instruments which call for contingent payments. The initial set of proposed regulations dealing with this topic were issued on April 8, 1986, and modified on February 26, 1991 (the Old Proposed Regulations). A second set of proposed contingent payment regulations were issued on January 19, 1993, but were withdrawn prior to publication in the Federal Register. On December 15, 1994, the IRS replaced the Old Proposed Regulations by issuing a third set of proposed regulations addressing debt obligations that provide for contingent payments (the New Proposed Regulations). The New Proposed Regulations were proposed to be effective for debt obligations issued on or after the date that is sixty days following the promulgation of the New Proposed Regulations in final form. In this regard, the New Proposed Regulations have been adopted in final form (the Final Regulations), though effective only for debt instruments issued after August 12, 1996. Thus, by their terms, the New Proposed Regulations and the Final Regulations do not apply to the Term NPI. However, the Preamble to the Final Regulations provides that for debt instruments issued prior to the effective date of the Final Regulations, a taxpayer may use any reasonable method to account for such debt instruments, including a method that would have been permitted under the proposed regulations when the debt instrument was issued.

The Trustee understands that, in accordance with the foregoing, Eastern American, as obligor under the Term NPI, intends to continue to treat the Term NPI in the manner provided under the Old Proposed Regulations, which were proposed at the time the Term NPI was transferred to the Trust and Trust Units were issued. Under this approach, each payment (at the time the amount of such payment becomes fixed) made to the Trust with respect to the Term NPI will be treated first as a payment of interest to the extent of interest deemed accrued under the OID rules and the excess (if any) will be treated as a payment of principal. The total amount treated as principal will be limited to a portion of the purchase price of each Depositary Unit allocated to the Term NPI. For purposes of determining the amount of accrued interest, the Old Proposed Regulations required the use of the Applicable Federal Rate based on the due date of the final payment due under the terms of the production payment, which for the Term NPI is May 15, 2013.

Unitholders are also required to recognize and report OID interest income attributable to the Treasury Obligations. In general, the total amount of OID a Unitholder is required to recognize will be calculated as the difference between the amount of the purchase price of a Depositary Unit allocated to the Treasury Obligations and the pro rata portion of the face amount of such Treasury Obligations attributable to the Depositary Unit. The amount of OID so calculated is included in income by a Unitholder on the basis of a constant interest rate computation.

Royalty Income and Depletion

The income from the Royalty NPI is royalty income subject to an allowance for depletion. The depletion allowance must be computed separately by each Unitholder for each oil or gas property (within the meaning of Code Section 614). The IRS presently takes the position that a net profits interest burdening multiple properties is one property for depletion purposes. Accordingly, the tax information reports that the Trust provides to Unitholders and the IRS have reported all production attributable to the Royalty NPI as production attributable to a single property for depletion purposes. Such reporting treatment is expected to continue until at least the IRS position on such treatment is changed.

The allowance for depletion with respect to a property is determined annually and is the greater of cost depletion or, if allowable, percentage depletion. Percentage depletion is generally available to independent producers (generally persons who are not substantial refiners or retailers of oil or gas or their primary products) on the equivalent of 1,000 barrels of production per day. Percentage depletion is a statutory allowance equal to 15% of the gross income from production from a property which is included in income by a taxpayer.

Percentage depletion is subject to a net income limitation which is 100% of the taxable income from the property, computed without regard to depletion deductions and certain loss carrybacks. A taxpayer s total percentage depletion deduction for all properties for a taxable year is limited to 65% of the taxpayer s taxable income for the year, before percentage depletion and certain other deductions. Unlike cost depletion, percentage depletion is not limited to the adjusted tax basis of the property, although it reduces that adjusted tax basis (but not below zero).

In computing cost depletion for each property for any year, the adjusted tax basis of that property at the end of that year is divided by the estimated total units (Mcf of gas) recoverable from that property to determine the per-unit allowance for such property. The per-unit allowance is then multiplied by the number of units produced and sold from that property during the year. Cost depletion for a property cannot exceed the adjusted tax basis of such property. While the Trust is treated as a grantor trust for Federal income tax purposes, each Unitholder computes cost depletion by using as his basis for the property the portion of his cost basis for his Depositary Units that is allocated first to the NPI and second to the Royalty NPI. Information is provided by the Trustee to each Unitholder reflecting how that basis should be allocated.

Section 29 Credit

The Trustee has been informed by Eastern American that most of the production attributable to the Royalty NPI is gas produced from Devonian shale or a tight formation. Provided a number of requirements are met, taxpayers are entitled to the Section 29 Credit for gas produced from Devonian shale or a tight formation. The Section 29 Credit generally applies only to gas produced from Devonian shale or a tight formation in the United States and sold to an unrelated party prior to January 1, 2003, from wells drilled after December 31, 1979, and prior to January 1, 1993. Additionally, the Section 29 Credit applies only to gas produced from a tight formation which, as of April 20, 1977, was committed or dedicated to interstate commerce (as defined in Section 2(18) of the Natural Gas Policy Act, as in effect on November 5, 1990), or which is produced from a well drilled after November 5, 1990. A Unitholder is eligible to claim the Section 29 Credit with respect to certain sales of such gas attributable to the Royalty NPI. Under current law, the Section 29 credit is no longer available for production after December 31, 2002.

Section 29 Credits resulting from an investment in Depositary Units may only be used to reduce a taxpayer s regular income tax liability and generally may not be used to reduce a taxpayer s liability for alternative minimum tax. Section 29 Credits available to a taxpayer in any taxable year may not be carried back but may be carried forward for use by that taxpayer in a subsequent tax year only in a limited fashion. See Alternative Minimum Tax below.

The Section 29 Credit is not available for production after December 31, 2002. Congress in past years has considered, without enacting, legislation to extend energy tax credits such as the Section 29 Credit beyond their expiration date or to create new similar credits. The potential effect that enactment of any such possible legislation may have on Unitholders in the future is unknown.

On March 23, 1999, the United States Tax Court of Appeals for the Tenth Circuit affirmed a lower court decision in *True Oil Company v.* C.I.R. 170 F.3d 1294. The Court ruled that, in order to be eligible for credits under Section 29 of the Internal Revenue Code, each well from which gas is produced from Devonian shale or a tight formation must receive a determination from the Federal Energy Regulatory Commission (FERC) that the gas produced is, in fact, produced from Devonian shale or a tight formation. Eastern American has verified that most producing gas wells subject to the Royalty NPI have received a well category determination from FERC. Should the Internal Revenue Service challenge the amount of the Trust s production qualifying for Section 29 Credits, a Unitholder might not be able to claim the benefit of Section 29 credits for production attributable to a well that did not receive a FERC determination. If successful, such a challenge could affect the tax reporting for such credits for tax years examined by the IRS and any subsequent tax years. However, it should be noted that under current law the Section 29 credit is no longer available for production after December 31, 2002.

Other Income and Expenses

From time to time, the Trust may generate interest income on funds held as a reserve or held until the next distribution date. Expenses of the Trust include administrative expenses of the Trustee. Under the Code, certain miscellaneous itemized deductions of an individual taxpayer are deductible only to the extent that in the aggregate they exceed 2% of the taxpayer s adjusted gross income. Certain administrative expenses attributable to the Trust Units may have to be aggregated with an individual Unitholder s other miscellaneous itemized deductions to determine the excess over 2% of adjusted gross income. To date the amount of such expenses has not been significant in relation to the Trust s income.

Alternative Minimum Tax

The Code imposes a minimum tax (known as an alternative minimum tax or AMT) on each taxpayer to the extent that his tentative minimum tax in any taxable year exceeds his regular tax for that year. For purposes of computing the AMT, the taxpayer s taxable income is recomputed with various adjustments plus items of tax preference .

A taxpayer is generally entitled to a credit against, or reduction in, his regular tax liability in a subsequent year in an amount equal to the AMT he pays for a prior taxable year. However, that credit can only be used to reduce his regular tax liability for that subsequent year to the extent his regular tax liability for that subsequent year exceeds his tentative minimum tax liability for that subsequent year.

The Section 29 Credit allowable to a taxpayer as a reduction of his tax liability for any prior taxable year could not have exceeded the excess of his regular tax liability for such taxable year, as reduced by his foreign tax credits and certain nonrefundable credits, over his tentative minimum tax liability for that year. Any amount of Section 29 Credit disallowed for the prior tax year solely because of this limitation will increase a taxpayer s credit for the prior year s AMT, as described above. There is no provision for the carryback or carryforward of the Section 29 Credit in any other circumstances. Therefore, a Unitholder may not have received the full benefit of available Section 29 Credits, depending on his particular AMT circumstances. However, it should be noted that under current law the Section 29 credit is no longer available for production after December 31, 2002.

Since the effect of the AMT varies depending upon each Unitholder s personal tax and financial position, each Unitholder is advised to consult with his, her or its own tax advisor concerning the effect of the AMT and Section 29 Credits attributable to an investment in the Depositary Units.

Non-Passive Activity

The income, credits and expenses of the Trust are not taken into account in computing the passive activity losses and income under Code Section 469 for a Unitholder who acquires and holds Depositary Units as an investment and did not acquire them in the ordinary course of business.

Unrelated Business Taxable Income

Certain organizations that are generally exempt from tax under Code Section 501 are subject to tax on certain types of business income defined in Code Section 512 as unrelated business income. The income of the Trust is not unrelated business taxable income within the meaning of Code Section 512 so long as the Trust Units are not debt-financed property within the meaning of Code Section 524(b). In general, a Trust Unit would be debt-financed if the Unitholder incurs debt to acquire a Trust Unit or otherwise incurs or maintains a debt that would not have been incurred or maintained if such Trust Unit had not been acquired. Legislative proposals have been made from time to time which, if adopted, would result in the treatment of income attributable to the Royalty NPI as unrelated business income.

Sale of Depositary Units; Sale of Trust Units or Treasury Obligations

Generally, a Unitholder will realize gain or loss on the sale or exchange of his Depositary Units measured by the difference between the amount realized on the sale or exchange and his adjusted basis for such Depositary Units. Gain or loss on the sale of Depositary Units by a Unitholder who is not a dealer with respect to such Depositary Units and who has a holding period for the Depositary Units of more than one year will be treated as long-term capital gain or loss, except to the extent of the depletion recapture amount and any accrued market discount as explained below. A Unitholder s initial basis in his Depositary Units is equal to the amount paid for such Depositary Units. Such basis is increased by the amount of OID income recognized by the Unitholder attributable to the Treasury Obligations. Such basis is reduced by deductions for depletion claimed by the Unitholder (but not below zero). In addition, such basis is reduced by the amount of any payments attributable to the Term NPI which are treated as payments of principal under the OID rules.

For Federal income tax purposes, the sale of a Depositary Unit is treated as a sale by the Unitholder of his interest in the Treasury Obligations and the assets of the Trust. Thus, upon the sale of Depositary Units, a Unitholder must treat as ordinary income his depletion recapture amount, which is an amount equal to the lesser of (i) the gain on that sale attributable to disposition of the Royalty NPI or (ii) the sum of the prior depletion deductions taken with respect to the Royalty NPI (but not in excess of the initial basis of such Depositary Units allocated to the Royalty NPI). It is possible that the IRS would take the position that a portion of the sales proceeds is ordinary income to the extent of any accrued income at the time of sale allocable to the Depositary Units sold, but which is not distributed to the selling Unitholder.

A Unitholder who allocates his purchase price (or is required to allocate his purchase price) to the Treasury Obligations in an amount less than the sum of (a) his share of the initial issue price of the Treasury Obligations and (b) his share of OID income recognized by prior holders of the Treasury Obligations (any such difference represents market discount) will generally be required to recognize ordinary income to the extent of any accrued market discount upon sale of the Depositary Units. In general, accrued market discount is an amount which bears the same ratio to total market discount as the number of days which a Unitholder holds a Depositary Unit bears to the number of days after the date the Unitholder acquired the Depositary Unit and up to and including the Liquidation Date.

Withdrawal of Trust Units or Treasury Obligations

A Unitholder will recognize no gain or loss upon the withdrawal of the Trust Units or Treasury Obligations from the Depositary. A sale of the Trust Units or the Treasury Obligations will result in the recognition of income or loss.

Sale of Net Profits Interests or Production Payment

A sale by the Trust of Net Profits Interests are treated for Federal income tax purposes as a sale of Net Profits Interests by a Unitholder. Thus, a Unitholder will recognize gain or loss on a sale of Net Profits Interests by the Trust. A portion of that income may be treated as ordinary income to the extent of depletion recapture. Receipt by the Trust of proceeds drawn from the letter of credit supporting Eastern Marketing s obligations under the Gas Purchase Contract is, in certain cases, in consideration for the conveyance to Eastern Marketing of a production payment interest in reserves attributable to the Net Profits Interests or to compensate the Trust for damages from a breach of the Gas Purchase Contract. All or a portion of such proceeds may be treated as non-taxable loan proceeds attributable to a loan by Eastern Marketing resulting from the production payment, may be treated as ordinary income not subject to depletion or may receive some other treatment, depending upon facts existing at that time. To the extent receipt of such proceeds is attributable to a sale of reserves by the Trust, depletion and Section 29 Credits available to the Unitholders for subsequent periods is reduced.

Backup Withholding

In general, distributions of Trust income are not subject to backup withholding unless (i) the Unitholder is an individual or other noncorporate taxpayer and (ii) such Unitholder fails to comply with certain reporting procedures.

Tax Shelter Registration

The Trust has been registered with the IRS as a tax shelter, and has received tax shelter registration number 93040000163. A tax shelter, for purposes of the registration requirement, is an investment with respect to which a person could reasonably infer, from the representations made in connection with any offer for sale of any interest in the investment, that the tax shelter ratio for any investor may be greater than two to one as of the close of any of the first five years ending after the date on which the investment is offered for sale. The term tax shelter ratio with respect to an investment means the ratio that the aggregate amount of gross deductions for any investor, determined without regard to income derived from the investment, plus 350% of the credits that are potentially available to an investor, bears to the investment base for the year. The investment base is equal to the cash, plus the adjusted basis (which may be less than the fair market value) of any other property invested. Certain borrowings, however, including those from other participants in the venture, are excluded from the investment base. While Eastern American has no knowledge of any such borrowings, it is possible that, due to such borrowings, the investment base of an investor would be substantially reduced or eliminated.

A Unitholder who sells or otherwise transfers a Trust Unit must furnish to the transferee the tax shelter registration number set forth above. The penalty for failure of the transferor of a Trust Unit to furnish such tax shelter registration number to a transferee is $100 for each such failure. Unitholders must disclose the tax shelter registration number of the Trust on Form 8271 to be attached to the tax return on which any deduction, loss, credit or other benefit generated by the Trust is claimed or income of the Trust is included. A Unitholder who fails to disclose the tax shelter registration number on his return, without reasonable cause for such failure, will be subject to a $250 penalty for each such failure. (Any penalties discussed herein are not deductible for income tax purposes.)

ISSUANCE OF A TAX SHELTER REGISTRATION NUMBER DOES NOT INDICATE THIS INVESTMENT OR THE CLAIMED TAX BENEFITS HAVE BEEN REVIEWED, EXAMINED OR APPROVED BY THE IRS.

STATE TAX CONSIDERATIONS

The following is intended as a brief summary of certain information regarding state income taxes and other state tax matters affecting individual Unitholders. Unitholders are urged to consult their own legal and tax advisors with respect to these matters.

The Trust owns the Net Profits Interests burdening the Underlying Properties located in the states of Pennsylvania and West Virginia. Both of these states have income taxes applicable to individuals and may require the Trust to withhold taxes from distributions made to nonresident Unitholders. Withholding, if required, is at the rate of 4% of taxable income attributable to West Virginia and 3.07% of taxable income attributable to Pennsylvania. A Unitholder may be required to file state income tax returns and/or to pay taxes in these states and may be subject to penalties for failure to comply with such requirements. Generally, Unitholders may treat state income taxes that the Trust has withheld as having been paid by them to the state for which they were withheld. Unitholders may be able to treat any taxes that they have paid or that have been withheld and paid to West Virginia or Pennsylvania as a deduction in computing Federal income tax, or as a credit or a deduction in computing another state s income tax.

Unitholders receive information concerning the Depositary Units and the Trust Units sufficient to identify the income from Depositary Units that is allocable to each state. Holders of Depositary Units should consult their own tax advisors to determine their income tax filing requirements with respect to their share of income of the Trust allocable to states imposing a tax on such income.

The Trust Units and therefore also the Depositary Units may constitute real property or an interest in real property under the tax, inheritance, estate and probate laws of either or both of Pennsylvania and West Virginia. If the Depositary Units are held to be real property or an interest in real property under the laws of a state in which the Underlying Properties are located, the holders of Depositary Units may be subject to ad valorem or other property tax, devolution, probate and administration laws, and inheritance or estate and similar taxes, under the laws of such state.

Available Information

The Trust does not maintain an internet address or a website, and therefore does not make copies of its reports under the Exchange Act available in that manner. The Trust s filings under the Exchange Act are available electronically from the website maintained by the Securities and Exchange Commission at http://www.sec.gov. The Trust will also provide electronic copies of its recent filings free of charge upon request to the Trustee, and will provide paper copies of its recent filings for its costs of reproduction upon request to the Trustee.

Item 1A. *Risk Factors*

Following is a summary of the principal risks associated with an investment in Units in the Trust.

Natural gas prices fluctuate due to a number of factors, and lower prices will reduce net proceeds to the Trust and distributions to Unitholders.

The Trust s revenues and distributions to Unitholders are highly dependent on the sales prices as reflected in the Henry Hub Average Price, as defined in the Gas Purchase Contract, and on the quantities of natural gas attributable to the Net Profits Interests. Prices for natural gas can fluctuate widely in response to a number of factors that are beyond the control of Eastern American and the Trust. These factors include:

worldwide economic conditions;

weather conditions;

changes and expectations regarding natural gas production and transportation;

levels of actual and anticipated demand;

price and availability of alternative fuels;

the availability of gathering, transportation and processing facilities; and

the effects of worldwide energy conservation measures.

Low gas prices may reduce production.

Low natural gas prices may reduce the amount of gas that is economic to produce. As a result, the operator could determine during periods of low gas prices to shut in or curtail production. In addition, the operator could determine during periods of low gas prices to plug and abandon marginal wells.

Estimated reserves and future production levels are uncertain.

The value of the Depositary Units depends on, among other things, the proved reserves and production levels attributable to the Net Profits Interests. There are many uncertainties involved in estimating quantities and values of proved reserves and in projecting future rates of production. The reserve data included in this Annual Report are estimates only, and actual quantities and values of natural gas are likely to differ from the estimated amounts. The discounted present values shown for the Net Profits Interests were prepared using guidelines established by the SEC for disclosure of reserves and should not be considered representative of market value.

There are risks inherent in the development and production of natural gas.

Distributions to Unitholders could be adversely affected if any of the risks typically associated with the development, production and transportation of natural gas were to occur, including personal injuries, property damage, well damage and damage to productive formations or equipment.

None of the Trust, the Trustee nor the Unitholders has any control over the operation of the properties.

None of the Trust, Trustee nor the Unitholders is able to influence or control the operation of the properties. All of the wells are operated by Eastern American. As operator, Eastern American has the right to abandon or sell any well if, in its opinion, the well or property ceases to produce or is not capable of producing in commercially paying quantities. In general, upon abandonment of any well to which the Net Profits Interests relate, that portion of the Net Profits Interests will be extinguished.

Gas reserves are depleting assets.

Gas reserves are depleting assets. The reserves attributable to the Net Profits Interests have declined and are expected to continue to decline over time. The accreting value of the Treasury Obligations may not fully offset the depletion of the reserves attributable to the Net Profits Interests.

Compliance with government regulation may be expensive.

The production, transportation and sale of natural gas from the wells to which the Net Profits Interest relate are subject to governmental regulation. Compliance with these regulations may be expensive.

Operating costs, capital expenditures and taxes reduce payments to the Trust.

The operating costs charged in calculating Net Proceeds include a fixed charge, subject to increase of up to 5% annually. In addition, property and production taxes and certain capital expenditures are deducted from gross proceeds in determining the Net Proceeds. In general, increases in chargeable costs will have the effect of reducing the amount of Net Proceeds.

Increased administrative costs reduce distributions to Unitholders.

Administrative costs, including professional services fees and expenses, are deducted prior to distributions to Unitholders. Consequently, increases in administrative costs adversely affect distributions to Unitholders.

The Ensource exchange offer may result in additional increased administrative costs.

As described elsewhere in this Annual Report on Form 10-K, in November 2005 Ensource Energy Income Fund LP commenced an unsolicited exchange offer in an effort to acquire control of the Trust. The Trust has incurred substantially increased administrative costs as a result of the Ensource exchange offer, and may continue to do so for the duration of the Ensource exchange offer. All costs incurred by the Trust in connection with the Ensource offer decrease distributions to Unitholders.

The legal status of the Net Profits Interests under some circumstances is unclear.

At the time of the formation of the Trust, Eastern American noted that it was likely that the Net Profits Interests would not be treated as real property interests under the laws of West Virginia and Pennsylvania. Nevertheless, Eastern American recorded the Conveyances in the real property records of West Virginia and Pennsylvania in accordance with local recording acts. Eastern American believes that, if, during the term of the Trust, Eastern American becomes involved as a debtor in a bankruptcy proceeding under the Federal Bankruptcy Code, the Net Profits Interests relating to the Underlying Properties located in West Virginia would be treated as fully conveyed personal property interests. However, if the Conveyances were held to constitute executory contracts, and if such contracts were not to be assumed in a bankruptcy proceeding, the Trust probably would be treated as an unsecured creditor of Eastern American. With respect to the properties located in Pennsylvania, which represented approximately 10% of the reserves attributable to the Net Profits Interests at the inception of the Trust, Eastern American believed that there is a greater risk that the Net Profits Interests would not be treated as fully conveyed property interests and instead the Conveyances could be treated as executory contracts, meaning that the Trust could be treated as an unsecured creditor with respect to those interests.

The Net Profits Interests are subject to any defects in Eastern American s rights to the Underlying Properties.

The Net Profits Interests are subject to any defects in Eastern American s rights with respect to the Underlying Properties. Eastern American believes that its interests with respect to the Underlying Properties are good and defensible in accordance with standards generally accepted in the Appalachian oil and gas industry, subject to exceptions which do not detract substantially from the value of its interests. However, it is possible that leases or farmout agreements could be treated as executory contracts if the third party lessor or farmor under a farmout agreement were to become a debtor in bankruptcy, meaning that it is possible that a lease or farmout agreement could be rejected in a bankruptcy proceeding.

The opinion of tax counsel obtained at inception of the Trust is not binding on the IRS or any court.

At the inception of the Trust, Eastern American received an opinion of counsel that the Trust is a grantor trust and not an association taxable as a corporation for Federal income tax purposes, and that each Unitholder would be taxed directly on his pro rata share of the income attributable to assets of the Trust and, subject to certain limitations, would be entitled to claim depletion deductions and tax credits attributable to the Royalty NPI and would be entitled to claim his pro rata share of other deductions attributable to assets of the Trust. However, the opinion of counsel is not binding on the IRS or any court.

Taxable income could exceed cash distributions.

It is possible that taxable income per Depositary Unit may exceed cash distributions per Depositary Unit. In addition, to the extent that distributable cash is used to establish Trust reserves or to repay borrowed funds, Unitholders will recognize taxable income without receiving the cash used to establish reserves or to repay borrowed funds.

Eastern American and the Trust may have conflicts of interest.

The interests of Eastern American and the interests of the Trust and the Unitholders may at times be different. For example, Eastern American s interests may conflict with those of the Trust and Unitholders in situations involving the development, operation or abandonment of the Underlying Properties or adjacent properties. In making decisions with respect to such operations, or otherwise with respect to the development, operation or abandonment of the Underlying Properties, Eastern American is required to act as a reasonably prudent operator in the Appalachian Basin would act with respect to its own properties, without regard to the existence of the Net Profits Interests and without regard to any possible adverse effect on Eastern Marketing or Eastern American under the Gas Purchase Contract. In addition, Eastern American has agreed not to drill any well within 1,000 feet of any well subject to the Net Profits Interests which produces oil or gas from the same formations or horizons as any such producing well. These covenants would not prohibit Eastern American from drilling additional wells on the same property as the wells subject to the Net Profits Interests provided that Eastern American complies with both of these covenants. In addition, these covenants would not prohibit Eastern American from drilling development wells on adjacent properties provided that Eastern American complies with the 1,000 foot limitation. If Eastern American is permitted under these covenants to drill additional development wells near the wells subject to the Net Profits Interests, the additional wells could cause drainage of the reserves attributable to the Net Profits Interests. These covenants apply only to Eastern American, and do not apply to third parties.

In addition, Eastern American s interests may conflict with those of the Trust and the Unitholders in situations involving the sale of Underlying Properties. Eastern American has the right to sell all or any portion of the Underlying Properties without restrictions; however, except in limited circumstances where Eastern American may require the Trust to release the Net Profits Interests, the Conveyances provide that the purchaser of any of the Underlying Properties will acquire such Underlying Properties subject to the Net Profits Interests. The Conveyances provide that a purchaser will be subject to the same standards of conduct with respect to development, operation and abandonment of such Underlying Properties as are applicable to Eastern American. Eastern American has the right, subject to limitations, to cause the Trust to release a portion of the Net Profits Interests in connection with a sale of a portion of the Underlying Properties.

Unitholders have only limited voting rights.

While Unitholders have certain voting rights pursuant to the terms of the Trust Agreement, these rights are more limited than those of stockholders of most corporations. For example, there is no requirement for annual meetings of Unitholders or for an annual or other periodic re-election of the Trustee.

Unitholders could be subject to unlimited liability.

Consistent with Delaware law, the Trust Agreement provides that the Unitholders will have the same limitation on liability as is accorded under the laws of such state to stockholders of a corporation for profit. No assurance can be given, however, that the courts in jurisdictions outside of Delaware will give effect to such limitation.

There are risks associated with the financial position of Eastern American

Eastern American is a privately held, independent energy company engaged primarily in the exploration, development, production, transportation and marketing of natural gas within the Appalachian Basin. The ability of Eastern Marketing and Eastern American to perform their obligations under the Gas Purchase Contract depends on their financial condition, which in turn depends upon the supply and demand for natural gas, economic conditions and upon financial, business and other factors, many of which are beyond the control of Eastern American.

None of the Trustee, the Trust nor the Unitholders has any control over the operation of the Underlying Properties.

None of the Trustee, the Trust nor the Unitholders has any influence or control over the operation of the Underlying Properties, all of which are operated by Eastern American.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 2. ***Properties*****.**

Reference is made to Item 1 of this Form 10-K.

Item 3. ***Legal Proceedings*****.**

None.

Item 4. ***Submission of Matters to a Vote of Unitholders*****.**

None.

PART II

Item 5. ***Market for the Registrant s Common Equity, Related Unitholders Matters and Issuer Purchases of Equity Securities .***

The Depositary Units are traded on the New York Stock Exchange under the ticker symbol NGT . The high and low prices and distributions paid during the quarters in the three-year period ended December 31, 2005 were as follows:

Quarter	High	Low	Distributions Paid
2003:			
First (to March 31, 2003)	$ 19.58	$ 18.70	$ 0.38
Second (to June 30, 2003)	$ 22.28	$ 18.87	$ 0.52
Third (to September 30, 2003)	$ 23.55	$ 20.83	$ 0.51
Fourth (to December 31, 2003)	$ 26.03	$ 22.10	$ 0.41
2004:			
First (to March 31, 2004)	$ 27.40	$ 22.95	$ 0.43
Second (to June 30, 2004)	$ 23.80	$ 20.95	$ 0.49
Third (to September 30, 2004)	$ 25.65	$ 23.41	$ 0.48
Fourth (to December 31, 2004)	$ 27.00	$ 24.75	$ 0.62
2005:			
First (to March 31, 2005)	$ 28.90	$ 24.40	$ 0.50
Second (to June 30, 2005)	$ 28.11	$ 25.45	$ 0.51
Third (to September 30, 2005)	$ 31.58	$ 27.62	$ 0.64
Fourth (to December 31, 2005)	$ 31.20	$ 26.75	$ 0.67

At February 28, 2006, the 5,900,000 Depositary Units outstanding were held by approximately 241 Unitholders of record.

With respect to the Treasury Obligations, the high and low closing prices per $1,000 face amount for the period from January 1, 2005 to December 31, 2005 were $735.45 and $684.40, respectively. The closing price on December 31, 2005 was $722.26 per $1,000 face amount.

During the fourth quarter of 2005, there were no purchases of Units made by or on behalf of the Trust or any affiliated purchaser as defined in Rule 10b-18 (a) (3) under the Exchange Act.

Item 6. ***Selected Financial Data.***

		December 31, 2005		December 31, 2004		December 31, 2003		December 31, 2002		December 31, 2001
Royalty Income	$	18,179,459	$	14,449,208	$	13,177,510	$	9,024,646	$	13,260,202
Distributable Income	$	14,597,387	$	12,019,847	$	10,947,816	$	7,808,725	$	11,268,383
Distribution Amount	$	13,712,387	$	11,919,847	$	10,732,816	$	7,808,725	$	11,268,383
Distributable Income per unit	$	2.47	$	2.04	$	1.86	$	1.32	$	1.91
Distribution Amount per unit	$	2.32	$	2.02	$	1.82	$	1.32	$	1.91
Total assets at year end	$	32,954,834	$	35,000,087	$	37,436,640	$	41,006,654	$	45,129,170

Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations.***

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 to Unitholders cash which the Trust receives in respect of the Net Profits Interests and to perform certain administrative functions in respect of the Net Profits Interests and the Depositary Units. The Trust derives substantially all of its income and cash flows from the Net Profits Interests.

Under the Gas Purchase Contract, Eastern Marketing purchases gas from the Trust at a variable price for any quarter 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 which is traded on the New York Mercantile Exchange.

Accordingly, the price payable to the Trust for production may vary based on 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 the Unitholders.

During 2003, a Coal Lessee contacted Eastern American and inquired as to whether it would sell the U.S. Steel Well # 26, which is a well in which the Trust owns a Net Profits Interests. The Coal Lessee stated that the well would materially interfere with the Coal Lessee s proposed mining operations. Eastern American reviewed the Trust Agreement and production from this well to determine if it could cause the Trust to sell its Net Profits Interest in the well. Upon review, it was discovered that the Net Profits Interests associated with the U.S. Steel #26 well accounted for less than

0.25% of the total production from the Underlying Properties for the prior twelve (12) month period. Eastern American advised the Coal Lessee that it could sell this well. Eastern American received $11,437 for the sale of the U.S Steel Well #26. The Trust s share of the proceeds of $10,293 was included in the Distributable Income of the Trust during the year ended December 31, 2003.

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 owned 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 was less than $500,000; (ii) the Assignee of the Horne Underlying Properties was 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) represented 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 Trust s share of the proceeds of $80,205 was included in the Distributable Income of the Trust during the year ended December 31, 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 owned 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 need to be disposed of for similar or other reasons.

The Trust is responsible for paying the Trustee s fees and all legal, accounting, engineering and stock exchange fees, printing costs and other administrative expenses incurred by or at the direction of the Trustee. The total of all Trustee fees and Trust administrative expenses for 2005 was $1,474,570 including the Trustee s fee of $108,000. In addition to such expenses, in 2005, the Trust paid Eastern American an overhead reimbursement of $317,324. The overhead reimbursement increases by 3.5% per year and is payable quarterly.

On December 8, 2004, the Trust announced approval by the Trust Unitholders of a proposal to elect JPMorgan Chase to serve as successor trustee of the Trust upon the effective date of the resignation of The Bank of New York as trustee of and depositary for the Trust and to amend the Trust Agreement to change the compensation of the Trustee. The resignation of The Bank of New York took effect on January 1, 2005. As successor trustee, JPMorgan Chase receives annual compensation of $108,000, plus fees and expenses.

During the last two quarters of 2005, the Trust incurred substantially increased fees for professional services relating to the Ensource exchange offer mentioned on Page 2. These expenses, and any other expenses, will decrease distributions to the Unitholders. Expenses relating to the Ensource exchange offer incurred by the Trust during 2005 total approximately $725,798, including $418,639 for fees and expenses the Trust paid to a financial advisory firm in connection with its analysis of the Ensource exchange offer. In addition, the Trust has incurred and is likely to continue to incur additional increased legal and other expenses relating to the Ensource exchange offer. The aggregate amount of future additional expenses could be substantially greater or less than the 2005 expenses.

The costs the Trust incurs in the future will fluctuate depending primarily on the expenses the Trust incurs for professional services, particularly legal, accounting and engineering services. If Ensource makes a substantially different offer to acquire control of the Trust, the Trust could incur substantial additional fees for additional financial advisory services and other professional and administrative expenses.

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.

Income Taxes:

Tax counsel to the Trust advised the Trust at the time of formation that, under then current tax laws, the Trust would be classified as a grantor trust for federal and state income tax purposes and, therefore, would not be subject to taxation at the Trust level. The Trust continues to be tax exempt. Accordingly, no provision for federal or state income taxes has been made. However, the opinion of tax counsel is not binding on taxing authorities.

New Accounting Standards

In May 2005, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 154 (SFAS 154), Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20, Accounting Changes and SFAS No. 3, Reporting Accounting Changes in Interim Financial Statements in order to change the requirements for the accounting and reporting of a change in accounting principal. SFAS 154 applies to all voluntary changed in accounting principal and changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. The Statement requires retrospective application to prior periods financial statements of changes in accounting principal, unless it is impractical to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 becomes effective for accounting changes and corrections of errors incurred during the fiscal years beginning after December 15, 2005. The Trust does not expect the adoption of SFAS 154 to have a material impact on the Trust s financial statements.

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 expenses and the amount of established reserves, are distributed currently to the Unitholders.

The Trust did not have any contractual obligations as of December 31, 2005. At December 31, 2005, the Trust had accounts payable of $318,120 and distributions payable of $3,933,449.

Results of Operations

2005 Compared with 2004

The Trust s distributable income was $14,597,387 for the twelve months ended December 31, 2005 as compared to $12,019,847 for the twelve months ended December 31, 2004. This increase was due to an increase in Royalty Income for the twelve months ended December 31, 2005 ($18,179,459) as compared to the twelve months ended December 31, 2004 ($14,449,208). 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 ($9.315 per Mcf for the twelve months ended December 31, 2005; $6.989 per Mcf for the twelve months ended December 31, 2004). This increase was offset by a decrease in production of gas attributable to the Net Profits Interests for the twelve months ended December 31, 2005 (1,956 Mmcf) as compared to the twelve months ended December 31, 2004 (2,068 Mmcf). The decline in production is primarily attributable to natural production declines and the sale of wells. Taxes on production and property were $1,256,330 for the twelve months ended December 31, 2005 as compared to $989,430 for the twelve months ended December 31, 2004. The increase in taxes is due directly to the increase in Royalty Income as discussed above. The production tax for the quarter also includes one month of charges related to a new West Virginia tax on the Severance of Natural Resources that is effective for gas produced after November 30, 2005. The additional Severance Tax rate is four and seven-tenths cents per MCF. Trust general and administrative expenses were $1,791,894 for the twelve months ended December 31, 2005 as compared to $1,002,397 for the twelve months ended December 31, 2004. The increase of $789,497 in general and administrative expenses was due primarily to professional fees of approximately $725,798 incurred as a direct result of the Ensource exchange offer as described on Page 2. The distributable income includes no Cash Proceeds on Sale of Net Profits Interests for the period ended December 31, 2005, while $80,205 was recognized in the corresponding prior twelve months.

During the twelve months ended December 31, 2005, the Trustee added an additional $885,000 to the cash reserve balance compared to the twelve months ended December 31, 2004 in the amount of $100,000. This reserve was established to facilitate the payment of vendor invoices on a timely basis. The increase of this reserve reduced the Distribution Amount by $885,000 or $0.15 per unit for the twelve months ended December 31, 2005 and by $100,000 or $0.0169 per unit for the twelve months ended December 31, 2004. Amortization of Nets Profits Interests in Gas Properties was $3,321,243 for the twelve months ended December 31, 2005 as compared to $3,818,158 for the twelve months ended December 31, 2004. This decrease was due to the decrease in production volumes and a decrease in the depletion rate to $1.6976 for the twelve months ended December 31, 2005 from $1.8465 for the year ended December 31, 2004, due to higher reserves.

The average price payable to the Trust for gas production attributable to the Net Profits Interests was $9.315 per Mcf for the twelve months ended December 31, 2005 and $6.989 per Mcf for the twelve months ended December 31, 2004. The price per Mcf was higher for the twelve months ended December 31, 2005 than for the corresponding twelve month period ended December 31, 2004 due to an increase in the average spot market price for gas delivered at the Henry Hub near Henry, Louisiana ($8.168 per Dth for the twelve months ended December 31, 2005; $6.054 per Dth for the twelve months ended December 31, 2004).

2004 Compared with 2003

The Trust s distributable income was $12,019,847 for the twelve months ended December 31, 2004 as compared to $10,947,816 for the twelve months ended December 31, 2003. This increase was due to an increase in Royalty Income for the twelve months ended December 31, 2004 ($14,449,208) as compared to the twelve months ended December 31, 2004 ($14,449,208) as compared to the twelve months ended December 31, 2003 ($13,177,510). 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 ($6.989 per Mcf for the twelve months ended December 31, 2004; $6.086 per Mcf for the twelve months ended December 31, 2003). This increase was offset by a decrease in production of gas attributable to the Net Profits Interests for the twelve months ended December 31, 2004 (2,068 Mmcf) as compared to the twelve months ended December 31, 2003 (2,161 Mmcf). The decline in production is primarily attributable to natural production declines and the sale of wells. Taxes on production and property were $989,430 for the twelve months ended December 31, 2004 as compared to $897,881 for the twelve months ended December 31, 2003. The increase in taxes is due directly to the increase in Royalty Income as discussed above. Trust general and administrative expenses were $1,002,397 for the twelve months ended December 31, 2004 as compared to $833,027 for the twelve months ended December 31, 2003. The increase in general and administrative expenses was due primarily to an increase in legal fees of $64,234 and $51,406 in direct expenses related to the resignation of the former trustee and the appointment of a successor trustee. The distributable income includes Cash Proceeds on Sale of Net Profits Interests of $80,205 for the period ended December 31, 2004, while $10,293 was recognized in the corresponding prior twelve months.

During the twelve months ended December 31, 2004, the Trustee added an additional $100,000 to the cash reserve balance which was established during the twelve months ended December 31, 2003 in the amount of $215,000. This reserve was established to facilitate the payment of vendor invoices on a timely basis. The establishment and subsequent increase of this reserve reduced the Distribution Amount by $100,000 or $0.0169 per unit for the twelve months ended December 31, 2004 and by $215,000 or $0.0365 per unit for the twelve months ended December 31, 2003. Amortization of Nets Profits Interests in Gas Properties was $3,818,158 for the twelve months ended December 31, 2004 as compared to $4,053,133 for the twelve months ended December 31, 2003. 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 $6.989 per Mcf for the twelve months ended December 31, 2004 and $6.086 per Mcf for the twelve months ended December 31, 2003. The price per Mcf was higher for the twelve months ended December 31, 2004 than for the corresponding twelve month period ended December 31, 2003 due to an increase in the average spot market price for gas delivered at the Henry Hub near Henry, Louisiana ($6.054 per Dth for the twelve months ended December 31, 2004; $5.233 per Dth for the twelve months ended December 31, 2003).

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.

Item 7A. ***Quantitative and Qualitative Disclosure 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 in detail elsewhere herein, the 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 Item 5. As described in detail 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.

Item 8. ***Financial Statements and Supplementary Data.***

Financial Statements

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

None.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

The Trustee maintains disclosure controls and procedures designed to ensure 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 ensure 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 Energy Corporation (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 December 31, 2005, the Trustee carried out an evaluation of the Trustee s disclosure controls and procedures. Mike Ulrich, as Trust Officer of the Trustee, has concluded that the disclosure controls and procedures are effective.

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 information relating to the Trust, including (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; and

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 and the independent reserve engineer, the Trustee made no independent or direct verification of this financial or other information.

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

The Trustee does not expect that the Trustee s disclosure controls and procedures or the Trustee s internal control over financial reporting will prevent all errors and all fraud. Further, the design of disclosure controls and procedures and internal control over financial reporting must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected.

Changes in Internal Control Over Financial Reporting

In connection with the evaluation by the Trustee of changes in internal control over financial reporting of the Trust that occurred during the Trust s last fiscal quarter, no change in the Trust s internal control over financial reporting was identified that has materially affected, or is reasonably likely to materially affect, the Trust s internal control over financial reporting.

Trustee s Report on Internal Control over Financial Reporting

The Trustee is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) promulgated under the Securities and Exchange Act of 1934, as amended. The Trustee conducted an evaluation of the effectiveness of the Trust s internal control over financial reporting based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Trustee s evaluation under the framework in *Internal Control-Integrated Framework*, the Trustee concluded that the Trust s internal control over financial reporting was effective as of December 31, 2005. The Trustee s assessment of the effectiveness of the Trust s internal control over financial reporting as of December 31, 2005 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

A registrant s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A registrant s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the registrant; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the registrant are being made only in accordance with authorizations of management and directors of the registrant; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the registrant s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Item 9B. ***Other Information.***

None.

PART III

Item 10. ***Directors and Executive Officers of the Registrant.***

The Trust has no directors or executive officers. The Trustee is a corporate trustee which may be removed by the affirmative vote of holders of a majority of the Trust Units then outstanding at a meeting of the Unitholders of the Trust at which a quorum is present. The Trust is not required to and does not hold annual meetings of the Unitholders.

The Trust also does not have an audit committee or body serving a similar function, and does not have an audit committee financial expert . The Trust has not adopted a code of ethics, as the Trust has no directors, officers, or employees. The Trust has not adopted a process by which Unitholders may communicate with board members, as the Trust has no board members or persons fulfilling a similar function. Unitholders may contact the Trustee at the following address: JPMorgan Chase Bank, N.A., Trustee of Eastern American Natural Gas Trust, Institutional Trust Services, 700 Lavaca, Austin, Texas 78701.

Item 11. ***Executive Compensation.***

The Trust has no officers or directors, and is administered by the Trustee. For the year ended December 31, 2005, JPMorgan Chase Bank, N.A., as Trustee received $108,000 and for the years ended December 31, 2004 and 2003, The Bank of New York as Trustee received $45,000 annually, as Trustee fees and $1,474,570, $650,805 and $491,803, respectively, as reimbursement of legal, accounting, and other professional expenses for such services. Effective January 1, 2005, the annual Trustee fee was fixed at $108,000.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management.***

(a) Security Ownership of Certain Beneficial Owners.

Based on filings with the Securities and Exchange Commission, the Trust is not aware of any person owning beneficially more than five percent of the Units as of March 1, 2006.

(b) Security Ownership of Management.

Not applicable.

(c) Changes in Control.

Except as described below, the Trust knows of no arrangements, including the pledge of securities of the Trust, the operation of which may at a subsequent date result in a change in control of the Trust. As described elsewhere herein and in more detail in the Trust s Schedule 14-D-9, Ensource Energy Income Fund LP, a newly formed Delaware limited partnership, has commenced an unsolicited exchange offer seeking control of the Trust.

(d) Securities authorized for issuance under equity compensation plans.

The Trust has no equity compensation plans.

Item 13. ***Certain Relationships and Related Transactions.***

None.

Item 14. ***Principal Accounting Fees and Services***

Audit Fees

The fees, including expenses, PricewaterhouseCoopers LLP billed the Trust for each of the last two fiscal years for professional services rendered in connection with the audits of the Trust s annual financial statements and review of the Trust quarterly interim financial statements were $185,250 in 2005 and $212,355 in 2004.

Audit-Related Fees

PricewaterhouseCoopers LLP did not bill the Trust any additional fees in the last two fiscal years for assurance and related services that are reasonably related to the performance of the audit or review of the Trust s financial statements.

Tax Fees

The fees, including expenses, PricewaterhouseCoopers LLP billed the Trust for each of the last two fiscal years for compliance, tax advice, or planning were $123,715 in 2005 and $126,484 in 2004.

All Other Fees

PricewaterhouseCoopers LLP did not bill the Trust any additional fees in the last two fiscal years for products and services provided by PricewaterhouseCoopers LLP, other than services reported above.

Pre-Approval Policies

The Trust does not have an audit committee or body performing a similar function. Pre-approval of all services performed by PricewaterhouseCoopers LLP and approval of the related fees is granted by the Trustee.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules.***

Reports
Reserve Report of Ryder Scott Company, Independent Petroleum Engineers

Financial Statements

The following financial statements are included in this Annual Report on Form 10-K on the pages indicated:

Schedules

All schedules have been omitted because they are not required, not applicable or the information required has been included elsewhere herein.

Exhibits

Except as otherwise indicated below, all exhibits, except Exhibit 31 and Exhibit 32, are incorporated herein 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.

Exhibit Number	
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 Contract between Eastern American Energy Corporation, Eastern American Marketing Corporation and Eastern American Natural Gas Trust
10.4	Form of Conveyance of Production Payment/Assignment of Production from Eastern American Natural Gas Trust to Eastern American Marketing Corporation
10.5	Form of Assignment and Standby Performance Agreement
31	Rule 13a-14(a)/15d-14(a) Certifications
32	Section 1350 Certifications

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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 on this 16th day of March, 2006.

EASTERN AMERICAN NATURAL GAS TRUST

By:	JPMorgan Chase Bank, N.A., Trustee
By:	/s/ Mike Ulrich
Name:	Mike Ulrich
Title:	Vice President

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

[Ryder Scott Company, Independent Petroleum Engineers Letterhead]

January 12, 2006

Eastern American Natural Gas Trust

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 December 31, 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 December 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 December 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.

	As of December 31, 2005		
	Gas (MMCF)	**Estimated Future Net Cash Inflows (M$)**	**Present Value At 10% (M$)**
Proved Net Developed			
Royalty NPI	11,266	141,923	59,278
Term NPI	5,997	75,540	54,992
Total	17,263	217,463	114,270

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 January 1, 2006 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 December 31, 2005 from this report are presented in the following table:

	As of December 31, 2005		
	Royalty NPI	**Term NPI**	**Totals**
Total Proved			
Future Cash Inflows (M$)	141,923	75,540	217,463
Future Costs			
Production (M$)	0	0	0
Development (M$)	0	0	0
Total Costs (M$)	0	0	0
Future Net Cash Inflows Before Income Tax (M$)	141,923	75,540	217,463
Present Value at 10% Before Income Tax (M$)	59,278	54,992	114,270

	As of December 31, 2005		
	Royalty NPI	**Term NPI**	**Totals**
Proved Net Developed Reserves			
Gas (MMCF)	11,266	5,997	17,263
Proved Net Undeveloped Reserves			
Gas (MMCF)	0	0	0
Total Proved Net Reserves			
Gas (MMCF)	11,266	5,997	17,263

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 December 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 December 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

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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 December 31, 2005 as $12.597 per Mcf, utilizing $11.152 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 September, 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. Properties which are not currently producing may start producing earlier or later than anticipated in our estimates of their future production rates.

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 December 31, 2005

SEC Parameters

	Proved		Total
	Developed	**Undeveloped**	**Proved**
Net Remaining Reserves			
Gas-MMCF	34,653	0	34,653

The estimated future net income associated with the foregoing volumes and the 10 percent discounted estimated future net income was $382,226,375 and $154,236,468, 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

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EASTERN AMERICAN NATURAL GAS TRUST

FINANCIAL STATEMENTS

as of December 31, 2005 and 2004

and for the years ended

December 31, 2005, 2004 and 2003

Report of Independent Registered Public Accounting Firm

To the Unit Holders of Eastern American Natural Gas Trust and JP Morgan Chase Bank, N.A., Trustee:

We have completed integrated audits of Eastern American Natural Gas Trust s 2005 and 2004 financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Financial statements

We have audited the accompanying statements of assets, liabilities and trust corpus of Eastern American Natural Gas Trust (the Trust) as of December 31, 2005 and 2004, and the related statements of distributable income, and changes in trust corpus for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Trustee. Our responsibility is to express an opinion on these financial statements based on our audits.

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

As described in Note 2, these financial statements were prepared on the basis of accounting prescribed by the Trust Agreement, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Trust at December 31, 2005 and 2004, and the distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2005, on the basis of accounting described in Note 2.

Internal control over financial reporting

Also, in our opinion, the Trustee s assessment, included in the Trustee s Report on Internal Control over Financial Reporting appearing under Item 9A, that the Trust maintained effective internal control over financial reporting as of December 31, 2005 based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control - Integrated Framework* issued by the COSO. The Trustee is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on the Trustee s assessment and on the effectiveness of the Trust s internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating the Trustee s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A trust s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A trust s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the trust; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the trust are being made only in accordance with authorizations of the trustee; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the trust s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Pittsburgh, Pennsylvania

March 16, 2006

EASTERN AMERICAN NATURAL GAS TRUST

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

as of December 31, 2005 and 2004

	2005		2004	
Assets:				
Cash	$	43,478	$	185,752
Net Proceeds Receivable		5,408,091		3,989,827
Net Profits Interests in Gas Properties		93,162,180		93,162,180
Accumulated Amortization		(65,658,915)		(62,337,672)
Total Assets	$	32,954,834	$	35,000,087
Liabilities and Trust Corpus:				
Trust General and Administrative Expenses Payable	$	318,120	$	220,596
Distributions Payable		3,933,449		3,639,983
Trust Corpus (5,900,000 Trust Units authorized and outstanding)		28,703,265		31,139,508
Total Liabilities and Trust Corpus	$	32,954,834	$	35,000,087

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

STATEMENTS OF DISTRIBUTABLE INCOME

for the years ended

December 31, 2005, 2004 and 2003

	2005	2004	2003
Royalty Income	$ 18,179,459	$ 14,449,208	$ 13,177,510
Operating Expenses:			
Taxes on production and property	1,256,330	989,430	897,881
Operating cost charges	534,348	519,228	510,032
Total Operating Expenses	1,790,678	1,508,658	1,407,913
Net Proceeds to the Trust	16,388,781	12,940,550	11,769,597
General and Administrative Expenses	(1,791,894)	(1,002,397)	(833,027)
Interest Income	500	1,489	953
Cash Proceeds on Sale of Net Profits Interests		80,205	10,293
Distributable Income	14,597,387	12,019,847	10,947,816
Cash Reserve	(885,000)	(100,000)	(215,000)
Distribution Amount	$ 13,712,387	$ 11,919,847	$ 10,732,816
Distributable Income Per Unit (5,900,000 units authorized and outstanding)	$ 2.4741	$ 2.0373	$ 1.8556
Distribution Amount Per Unit (5,900,000 units authorized and outstanding)	$ 2.3241	$ 2.0203	$ 1.8191

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

EASTERN AMERICAN NATURAL GAS TRUST

STATEMENTS OF CHANGES IN TRUST CORPUS

for the years ended

December 31, 2005, 2004 and 2003

	2005	2004	2003
Trust Corpus, Beginning of Period	$ 31,139,508	$ 34,857,666	$ 38,695,799
Distributable Income	14,597,387	12,019,847	10,947,816
Distributions Paid or Payable to Unitholders	(13,712,387)	(11,919,847)	(10,732,816)
Amortization of Net Profits Interests in Gas Properties	(3,321,243)	(3,818,158)	(4,053,133)
Trust Corpus, End of Period	$ 28,703,265	$ 31,139,508	$ 34,857,666

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

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EASTERN AMERICAN NATURAL GAS TRUST

NOTES TO FINANCIAL STATEMENTS

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 Bank of Montreal Trust Company. As a result, The Bank of New York served as Trustee (the Trustee). 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 of the Trust. The appointment of JPMorgan Chase Bank, N.A. as successor trustee became effective as of January 1, 2005. Consequently, references herein to the Trustee mean JPMorgan Chase Bank, N.A. as successor trustee, on and after January 1, 2005. References to the Trustee at any time prior to January 1, 2005 mean The Bank of New York as trustee. Effective January 1, 2005, the transfer agent for the Trust is Bondholder Communications.

The purpose of the Trust is to acquire and hold net profits interests owned by Eastern American in 650 producing gas wells and 65 proved development well locations in West Virginia and Pennsylvania (the Underlying Properties). The Underlying Properties are operated by Eastern American. The Net Profits Interests (the Net Profits Interests) consist of a Royalty interest in 322 wells and a Term interest in the remaining wells and locations. Eastern American drilled 59 of the 65 development wells.

The Royalty NPI is not limited in term or amount. Under the Trust Agreement, the Trustee is directed to sell all remaining Royalty NPI after May 15, 2012 and prior to May 15, 2013, and net proceeds from selling such Royalty NPI will be distributed to Unitholders on the first quarterly payment date following the receipt of such proceeds by the Trust. The Term NPI will expire on 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. As of December 31, 2005, 21,814 MMcf of such gas had been produced.

Eastern American can sell the Underlying Properties, subject to and burdened by the Net Profits Interests, without the consent of the Trustee or the Unitholders. In limited circumstances, Eastern American also can transfer the Underlying Properties and require the Trust to release the NPI burdening that property, without the consent of the Trustee or Unitholders, subject to payment to the Trust of the fair value of the interest released. In addition, any abandonment of a well included in the Underlying Properties or the Development Wells will extinguish that portion of the Net Profits Interests that relate to such well.

Four (4) of the remaining six (6) development wells were closely offset by third parties. Since the wells drilled by the third parties were within 1,000 feet of these development wells, Eastern American had a disagreement with the Trust over Eastern American s obligation to drill these closely offset development wells. The Trust has agreed that, in lieu of drilling these closely offset development wells Eastern American can 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 the Ryder Scott Company.

The two (2) remaining development wells were not drilled because Eastern American was unable to cure various title defects associated with these wells. Eastern American advised the Trust that it made a diligent effort to cure title but was unsuccessful. In West Virginia, an oil and gas well cannot be drilled unless a full and complete 100% leasehold interest is first obtained. Drilling an oil and gas well without obtaining the entire leasehold estate would expose the oil and gas operator and the Trust to a possible suit for trespass. Pursuant to the Term Net Profits Interest Conveyance, if the state of title to the drill site to any development well renders such property undrillable in the good faith opinion of Eastern American under the Reasonably Prudent Operator Standard then such drill site(s) shall be construed as a development well(s). Consequently, Eastern American has fulfilled its commitment to the Trust to drill the required number of development wells.

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. Of the net proceeds from

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EASTERN AMERICAN NATURAL GAS TRUST

NOTES TO FINANCIAL STATEMENTS

such offering, $27,787,820 was used to purchase $118,000,000 in face amount of Treasury Obligations and $93,162,180 was paid to Eastern American in consideration for the conveyance of the Net Profits Interests to the Trust. The Trust acquired the Net Profits Interests effective as of January 1, 1993. The Treasury Obligations are directly owned by the Unitholders and are not part of the Trust Corpus. The Treasury Obligations are on deposit with the Trustee pursuant to the Deposit Agreement.

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 which is contingent, uncertain in amount or that 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.

EASTERN AMERICAN NATURAL GAS TRUST

NOTES TO FINANCIAL STATEMENTS

2. Significant Accounting Policies:

The following is a summary of the significant 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.

Cash:

Cash consists of highly liquid instruments with maturities at the time of acquisition of three months or less.

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.

Significant dispositions or abandonment of the Underlying Properties are charged to Net Profits Interests and the 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 conveyance of the Royalty and Term Interests to the Trust was accounted for as a purchase transaction. The $93,162,180 reflected in the Statements of Assets, Liabilities and Trust Corpus as Net Profits Interests in Gas Properties represents 5,900,000 Trust Units valued at $20.50 per depository unit less the $27,787,820 paid for Treasury obligations. The carrying value of the Trust s investment in the Royalty Interests is not necessarily indicative of the fair value of such Royalty Interests.

Revenues and Expenses:

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 election of the Unitholders. Thus, the Statements of Distributable Income purport to show distributable income, defined as Trust income available for distribution to Unitholders before application of those Unitholders additional expenses, if any, for depletion, interest income and expense, and income taxes.

The Trust uses the accrual basis to recognize revenue, with royalty income recorded as reserves are extracted from the Underlying Properties and sold. Expenses are also recognized on an accrual basis. Operating expenses which include taxes on production and operating cost charges are recognized as incurred pursuant to the Conveyances on a per well production basis. The payment provisions of the gas purchase contract between the Trust and Eastern Marketing Corporation require 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.

EASTERN AMERICAN NATURAL GAS TRUST

NOTES TO FINANCIAL STATEMENTS

Use of Estimates in the Preparation of Financial Statements:

The preparation of financial statements requires the Trust to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Segment Information:

In 1998, the Trust adopted Statement of Financial Accounting Standards No. 131, Disclosure about Segments of an Enterprise and Related Information. The Trust s sole activity is earning royalty income from gas properties and, consequently, the Trust has only one operating segment, net profits interests in gas properties. Substantially all of the Trust s net profits interests are located in the Appalachian region.

3. Income Taxes:

Tax counsel to Eastern American advised Eastern American at the time of formation that, under then current tax laws, the Trust would be classified as a grantor trust for federal and state income tax purposes and, therefore, would not be subject to taxation at the Trust level. The Trust continues to be tax exempt. Accordingly, no provision for federal or state income taxes has been made. However, the opinion of tax counsel is not binding on taxing authorities.

The Unitholders are considered, for income tax purposes, to own the Trust s income and principal as though no trust were in existence. Thus, the taxable year for reporting a Unitholder s share of the Trust income, expense and credits are controlled by the Unitholder s taxable year and method of accounting, not the taxable year and method of accounting employed by the Trust.

4. Distributions to Unitholders:

The Trustee determines for each quarter the amount available for distribution to the Unitholders. Such amount will be equal to the excess, if any, of the cash received by the Trust, on or before the tenth day of the third month following the end of each calendar quarter ending prior to the dissolution of the Trust, from the Net Profits Interests then held by the Trust attributable to production during such quarter, plus, with certain exceptions, any other cash receipts of the Trust during such quarter, over the liabilities of the Trust paid during such quarter, subject to adjustments for changes made by the Trustee during such quarter in any cash reserves established at the discretion of the Trustee for the payment of contingent or future obligations of the Trust. Cash received by the Trustee in a particular quarter from the Net Profits Interests will reflect actual gas production for a portion of such quarter and a production estimate for the remainder of such quarter, such estimate to be adjusted to actual production in the following quarter. In accordance with the Trust Agreement and Delaware law, Unitholders should be shielded from direct liability for any environmental liabilities. However, costs and expenses incurred by Eastern American for certain Capital Costs associated with environmental liabilities arising after the effective date of the Conveyances would reduce Net Proceeds, and would therefore be borne, in part, by the Unitholders.

Net Proceeds Receivable included in the Statements of Assets, Liabilities and Trust Corpus as of December 31, 2005 are expected to be received by the Trust and distributed to the Unitholders on March 15, 2006. The December 31, 2004 Net Proceeds Receivable were received and distributed by the Trust on March 16, 2005.

5. Related Party Transactions:

The Trust is responsible for paying all legal, accounting, engineering and stock exchange fees, printing costs and other administrative expenses incurred at the direction of the Trustee. The total of all Trustee fees and Trust administrative expenses was $1,474,570 for the year ended December 31, 2005, $695,805 for the year ended December 31, 2004, and $536,803 for the year ended December 31, 2003. In accordance with the Trust Agreement, the Trustee pays Eastern American an annual fee which increases by 3.5% per year, payable quarterly, to reimburse Eastern American for overhead expenses. The initial fee at the inception of the Trust was $210,000. The Trustee paid Eastern American $317,324, $306,592 and $296,224 for overhead expenses for 2005, 2004 and 2003 respectively. Operating cost charges included in the Statements of Distributable Income are paid to Eastern American.

EASTERN AMERICAN NATURAL GAS TRUST

NOTES TO FINANCIAL STATEMENTS

Gas production attributable to the Net Profits Interests is purchased from the Trust by Eastern Marketing Corporation (Eastern Marketing), a wholly owned subsidiary of Eastern American, pursuant to a Gas Purchase Contract which effectively commenced as of January 1, 1993 and expires upon the termination of the Trust.

Pursuant to the Gas Purchase Contract, Eastern Marketing is obligated to purchase such gas production at a purchase price per Mcf equal to the greater of the Index Price, as defined below, or a Floor Price, for gas produced in any quarter during the Primary Term, which ended December 31, 1999. Effective January 1, 2000, Eastern Marketing is obligated to purchase such gas production at a purchase price per Mcf equal to the Index Price for gas produced in any quarter after the Primary Term.

The Index Price for any quarter subsequent to the Primary Term, which expired December 31, 1999, 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 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 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 prices 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 which is traded on the New York Mercantile Exchange.

Under a standby performance agreement Eastern American has agreed to make payments under the Gas Purchase Contract to the extent such payments are not made by Eastern Marketing.

Supplemental Reserve Information (Unaudited):

Information regarding estimates of the proved gas reserves attributable to the Trust are based on reports prepared by independent petroleum engineering consultants. Such estimates were prepared in accordance with guidelines established by the Securities and Exchange Commission. Accordingly, the estimates were based on existing economic and operating conditions. Numerous uncertainties are inherent in estimating reserve volumes and values and such estimates are subject to change as additional information becomes available.

The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimates.

The standardized measure of discounted future net cash flows was determined based on reserve estimates prepared by the independent petroleum engineering consultants. Fixed gas prices were used during the Primary Term, which ended December 31, 1999. The gas prices used thereafter are based solely on the fourth quarter Variable Price component.

The reserves and revenue values for the Underlying Properties transferred to the Trust were estimated from projections of reserves and revenue values attributable to the combined Eastern American and Trust interests in these properties. Reserve quantities are calculated differently for the Net Profits Interests because such interests do not entitle the Trust to a specific quantity of gas but to 90 percent of the Net Proceeds derived therefrom. Accordingly, there is no precise method of allocating estimates of the quantities of proved reserves between those held by the Trust and the interests to be retained by Eastern American. 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. The reserves presented for the Net Profits Interests reflect quantities of gas that are free of future costs or expenses. The allocation of proved reserves between the Trust and Eastern American will vary in the future as relative estimates of future gross revenues and future costs and expenses vary.

The royalty portion of the Net Profits Interests was calculated beyond the liquidation date of the Trust (May 15, 2013), even though the terms of the Trust Agreement require that the Royalty Net Profits Interest be sold by the Trustee on or about this date and a liquidating distribution from the sales proceeds from such sale would be made to the Unitholders. The Term Net Profits Interests was limited to the 20-year period as defined by the Trust Agreement.

The following table reconciles the change in proved reserves attributable to the Trust s share of the Net Profits Interests (NPI) from January 1, 2003 to December 31, 2005:

	Royalty NPI (MMcf)	Term NPI (MMcf)	Total NPI (MMcf)
Balance, January 1, 2003	12,025	8,609	20,634
Production	(932)	(1,229)	(2,161)
Revisions of previous estimates	201	87	288
Balance, December 31, 2003	11,294	7,467	18,761
Production	(910)	(1,158)	(2,068)
Revisions of previous estimates	1,072	393	1,464
Balance, December 31, 2004	11,456	6,702	18,158
Production	(849)	(1,107)	(1,956)
Revisions of previous estimates	659	402	1,061
Balance, December 31, 2005	11,266	5,997	17,263

The Trust s share of proved developed gas reserves are as follows:

	Royalty NPI (MMcf)	Term NPI (MMcf)	Total NPI (MMcf)
December 31, 2003	11,294	7,467	18,761
December 31, 2004	11,456	6,702	18,158
December 31, 2005	11,266	5,997	17,263

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves:

The following is the standardized measure of discounted future net cash flows as of December 31, 2005 (in thousands):

	Royalty NPI	Term NPI	Total NPI
Future cash inflows	$ 163,809	$ 83,267	$ 247,076
Future production taxes	(7,104)	(3,146)	(10,250)
Future production costs	(14,781)	(4,581)	(19,362)
Future net cash inflows	141,924	75,540	217,464
10% discount factor	(82,646)	(20,548)	(101,194)
Standardized measure of discounted future net cash flows	$ 59,278	$ 54,992	$ 114,270

The following is the standardized measure of discounted future net cash flows as of December 31, 2004 (in thousands):

	Royalty NPI	Term NPI	Total NPI
Future cash inflows	$ 110,781	$ 60,830	$ 171,612
Future production taxes	(6,130)	(2,942)	(9,073)
Future production costs	(12,765)	(4,130)	(16,895)
Future net cash inflows	91,886	53,758	145,644
10% discount factor	(53,480)	(15,968)	(69,448)
Standardized measure of discounted future net cash flows	$ 38,406	$ 37,790	$ 76,196

The following is the standardized measure of discounted future net cash flows as of December 31, 2003 (in thousands):

	Royalty NPI	Term NPI	Total NPI
Future cash inflows	$ 80,951	$ 49,043	$ 129,994
Future production taxes	(4,420)	(2,333)	(6,754)
Future production costs	(11,885)	(3,967)	(15,852)
Future net cash inflows	64,646	42,743	107,389
10% discount factor	(37,289)	(13,651)	(50,940)
Standardized measure of discounted future net cash flows	$ 27,357	$ 29,092	$ 56,449

Changes in Standardized Measure of Discounted Future Net Cash Flows:

The following schedule reconciles the changes during 2003, 2004 and 2005 in the standardized measure of discounted future net cash flows relating to proved reserves (in thousands):

	Royalty NPI	Term NPI	Total NPI
Standardized measure, January 1, 2002	$ 22,953	$ 25,358	$ 48,311
Net proceeds to the Trust	(7,085)	(4,684)	(11,770)
Revisions of previous estimates	1	0	1
Accretion of discount	2,295	2,536	4,831
Net change in price and production costs	7,405	4,926	12,331
Other	1,788	956	2,745
Standardized measure, December 31, 2003	$ 27,357	$ 29,092	$ 56,449
Net proceeds to the Trust	(8,164)	(4,776)	(12,941)
Revisions of previous estimates	4,498	1,649	6,148
Accretion of discount	2,736	2,909	5,645
Net change in price and production costs	12,331	7,491	19,822
Other	(352)	1,425	1,073
Standardized measure, December 31, 2004	$ 38,406	$ 37,790	$ 76,196
Net proceeds to the Trust	(11,864)	(6,315)	(18,179)
Revisions of previous estimates	4,362	2,661	7,023
Accretion of discount	3,841	3,779	7,620
Net change in price and production costs	25,240	11,848	37,088
Other	(707)	5,229	4,522
Standardized measure, December 31, 2005	$ 59,278	$ 54,992	$ 114,270

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Quarterly Financial Data (Unaudited):

The following is a summary of royalty income and distributable income per unit by quarter in 2005, 2004 and 2003 (all amounts in thousands except Distributable income per unit):

2005	Mar 31	June 30	Sept 30	Dec 31	Total
Royalty income	$ 3,648	$ 3,914	$ 4,659	$ 5,958	$ 18,179
Distributable income	$ 2,958	$ 3,206	$ 3,800	$ 4,633	$ 14,597
Distributable income per unit	$ 0.5014	$ 0.5434	$ 0.6440	$ 0.7853	$ 2.4741

2004	Mar 31	June 30	Sept 30	Dec 31	Total
Royalty income	$ 3,080	$ 3,492	$ 3,452	$ 4,425	$ 14,449
Distributable income	$ 2,512	$ 3,019	$ 2,849	$ 3,640	$ 12,020
Distributable income per unit	$ 0.4257	$ 0.5117	$ 0.4829	$ 0.6169	$ 2.0373

2003	Mar 31	June 30	Sept 30	Dec 31	Total
Royalty income	$ 2,999	$ 3,645	$ 3,521	$ 3,012	$ 13,177
Distributable income	$ 2,363	$ 3,054	$ 3,014	$ 2,517	$ 10,948
Distributable income per unit	$ 0.4005	$ 0.5175	$ 0.5109	$ 0.4266	$ 1.8556