QUICK PETER
Form 4
December 26, 2017

FORM 4

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

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

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

OMB APPROVAL

OMB Number:	3235-0287
Expires:	January 31, 2005
Estimated average burden hours per response...	0.5

(Print or Type Responses)

1. Name and Address of Reporting Person *
QUICK PETER

(Last) (First) (Middle)

THE FIRST NATIONAL BANK OF LONG ISLAND, 10 GLEN HEAD RD

(Street)

GLEN HEAD, NY 11545

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
FIRST OF LONG ISLAND CORP [FLIC]

3. Date of Earliest Transaction (Month/Day/Year)
12/22/2017

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

_____ Director _____ 10% Owner
_____ Officer (give title below) _____ Other (specify below)

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Stock	12/22/2017		A		85	A (1)	$ 0	20,222	D	
Common Stock								15,000	I	By LLC

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)		8. Price of Derivative Security (Instr. 5)	9. Nu Deriv Secur Bene Owne Follo Repo Trans (Instr
								Date Exercisable	Expiration Date	Title	Amount or Number of Shares		
				Code	V	(A)	(D)						

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
QUICK PETER THE FIRST NATIONAL BANK OF LONG ISLAND 10 GLEN HEAD RD GLEN HEAD, NY 11545				

Signatures

/s/William Aprigliano POA Peter Quick	12/26/2017
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) The shares represent stock received in lieu of director fees.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. ol "NGT." The high and low closing prices and distributions paid during the quarters in the two-year period ended December 31, 2009 were as follows:

Quarter	High	Low	Distributions Paid
2008:			
First (to March 31, 2008)	$ 28.60	$ 26.36	$ 0.4700
Second (to June 30, 2008)	$ 30.84	$ 27.65	$ 0.6706
Third (to September 30, 2008)	$ 30.61	$ 24.50	$ 0.7291
Fourth (to December 31, 2008)	$ 26.76	$ 22.74	$ 0.5116
2009:			
First (to March 31, 2009)	$ 26.92	$ 22.61	$ 0.3312
Second (to June 30, 2009)	$ 26.01	$ 23.86	$ 0.2515

Third (to September 30, 2009)	$ 24.25	$ 23.00	$ 0.2648
Fourth (to December 31, 2009)	$ 24.29	$ 23.23	$ 0.2587

At March 1, 2010, the 5,900,000 Depositary Units outstanding were held by approximately 200 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, 2009 to December 31, 2009 were $950.80 and $899.50, respectively. The closing price on December 31, 2009 was $935.90 per $1,000 face amount.

During the fourth quarter of 2009, 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.***

			Year Ended		
	December 31, 2009	December 31, 2008	December 31, 2007	December 31, 2006	December 31, 2005
Royalty Income	$ 8,868,114	$ 17,028,373	$ 14,660,909	$ 17,663,792	$ 18,179,459
Distributable Income	$ 6,526,597	$ 14,049,648	$ 12,006,605	$ 14,158,872	$ 14,597,387
Distribution Amount	$ 6,526,597	$ 14,049,648	$ 12,506,605	$ 14,658,872	$ 13,712,387
Distributable Income per unit	$ 1.1062	$ 2.3813	$ 2.0350	$ 2.3998	$ 2.4741
Distribution Amount per unit	$ 1.1062	$ 2.3813	$ 2.1198	$ 2.4846	$ 2.3241
Total assets at year end	$ 18,635,014	$ 22,570,038	$ 24,953,135	$ 28,165,747	$ 32,954,834

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

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.

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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 the fourth quarter of 2009 an oil and gas company contacted ECA to inquire as to whether it would assign the Bond J-748 gas well ("Well") which is a well in which the Trust owns a Net Profits Interest. ECA reviewed the Trust Agreement and certified to the Trustee that the Well could be sold free from the Net Profits Interest and that assignment of the Well did not conflict with the provisions of section 3.02 of the Second Amended and Restated Trust Agreement. The Well had not produced since 2006 due to mechanical problems and had become uneconomic to produce. The Well was assigned to avoid potential plugging and abandonment costs and liabilities. The Trust received no cash distribution for the assignment of the Well due to the fact that the Well was transferred for no cash consideration.

Also, during the fourth quarter of 2009 the Sheilds #1 gas well ("Well"), a Well in which the Trust owns a Net Profits Interest, was plugged and abandoned. The Well had not been producing due to down-hole mechanical problems and was no longer capable of commercial production. Therefore, the Well was plugged and abandoned in accordance with the regulations of the Pennsylvania Department of Environmental Protection.

Over the remaining life of the Trust, wells may be disposed of from time to time in accordance with the documents governing the Trust.

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 2009 was $615,789, including the Trustee's fee of $108,000. In addition to such expenses, in 2009, the Trust paid ECA an overhead reimbursement of $364,136. The overhead reimbursement increases by 3.5% per year and is payable quarterly. 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.

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 received annual compensation of

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$108,000 plus fees and expenses. Effective October 2, 2006, The Bank of New York Trust Company, N.A. (now known as The Bank of New York Mellon Trust Company, N.A.) acquired the corporate trust business of JPMorgan Chase Bank, N.A. Consequently, The Bank of New York Mellon Trust Company, N.A., currently serves as Trustee of the Trust. The Trustee's annual compensation did not change as a result of the October 2, 2006 acquisition by The Bank of New York Trust Company, N.A. of the corporate trust business of JPMorgan Chase.

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 assessed to determine whether their net capitalized cost is impaired, whenever events or changes in circumstances indicate that its carrying amount may not be recoverable, pursuant to The Financial Accounting Standards Board ("FASB") Accounting Standards Codification 360, Property, Plant and Equipment ("ASC 360"). 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 fair value of the investment in net profits interests 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 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.

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. The estimates include an estimate of the revenues attributable to the Trust from natural gas production for the last several months of the year, as the revenues from natural gas

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sales are typically received several months after delivery. Actual results could differ from those estimates.

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.

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, 2009. At December 31, 2009, the Trust had General and Administrative Expenses Payable of $213,744 and Distributions Payable of $1,526,481.

Results of Operations

2009 Compared with 2008

The Trust's Distributable Income was $6,526,597 for the year ended December 31, 2009 as compared to $14,049,648 for the year ended December 31, 2008. This decrease was due to a decrease in Royalty Income for the year ended December 31, 2009 ($8,868,114) as compared to the year ended December 31, 2008 ($17,028,373). The decrease in Royalty Income was due to a decrease in the average price payable to the Trust under the Gas Purchase Contract as discussed below ($5.534 per Mcf for the year ended December 31, 2009 as compared to $10.406 per Mcf for the year ended December 31, 2008). The decrease was also partially due to a decrease in production of gas attributable to the Net Profits Interests for the year ended December 31, 2009 (1,604 Mmcf) as compared to the year ended December 31, 2008 (1,637 Mmcf). The decline in production is primarily attributable to natural production declines. Taxes on Production and Property were $676,110 for the year ended December 31, 2009 as compared to $1,254,139 for the year ended December 31, 2008. The decrease in taxes is due directly to the decrease in Royalty Income as discussed above. Trust General and Administrative Expenses were $979,925 for the year ended December 31, 2009 as compared to $1,107,022 for the year ended December 31, 2008. The decrease in General and Administrative Expenses was due primarily to a decrease in professional fees incurred.

Amortization of Net Profits Interests in Gas Properties was $2,370,117 for the year ended December 31, 2009 as compared to $2,558,284 for the year ended December 31, 2008. This decrease was due to the decrease in production volumes and a decrease in the depletion rate to $1.4769 for the year ended December 31, 2009 from $1.5627 for the year ended December 31, 2008.

The average price payable to the Trust for gas production attributable to the Net Profits Interests was $5.534 per Mcf for the year ended December 31, 2009 and $10.406 per Mcf for the year ended December 31, 2008. The price per Mcf was lower for the year ended December 31, 2009 than for the year ended December 31, 2008 due to a decrease in the average spot market price for gas delivered at the Henry Hub near Henry, Louisiana ($4.731 per Dth for the year ended December 31, 2009 as compared to $9.160 per Dth for the year ended December 31, 2008).

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2008 Compared with 2007

The Trust's Distributable Income was $14,049,648 for the year ended December 31, 2008 as compared to $12,006,605 for the year ended December 31, 2007. This increase was due to an increase in Royalty Income for the year ended December 31, 2008 ($17,028,373) as compared to the year ended December 31, 2007 ($14,660,909). 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 ($10.406 per Mcf for the year ended December 31, 2008 as compared to $8.339 per Mcf for the year ended December 31, 2007). The increase was partially offset due to a decrease in production of gas attributable to the Net Profits Interests for the year ended December 31, 2008 (1,637 Mmcf) as compared to the year ended December 31, 2007 (1,758 Mmcf). The decline in production is primarily attributable to natural production declines. Taxes on Production and Property were $1,254,139 for the year ended December 31, 2008 as compared to $1,104,557 for the year ended December 31, 2007. The increase in taxes is due directly to the increase in Royalty Income as discussed above. Trust General and Administrative Expenses were $1,107,022 for the year ended December 31, 2008 as compared to $961,587 for the year ended December 31, 2007. The increase in General and Administrative Expenses was due primarily to an increase in professional fees incurred.

During the year ended December 31, 2008, the Trustee did not refund any amount from the Cash Reserve balance compared to the refunding of $500,000 from the cash reserve for the year ended December 31, 2007. This Reserve was established to facilitate the payment of vendor invoices on a timely basis. Amortization of Net Profits Interests in Gas Properties was $2,558,284 for the year ended December 31, 2008 as compared to $2,938,058 for the year ended December 31, 2007. This decrease was due to the decrease in production volumes and a decrease in the depletion rate to $1.5627 for the year ended December 31, 2008 from $1.6709 for the year ended December 31, 2007.

The average price payable to the Trust for gas production attributable to the Net Profits Interests was $10.406 per Mcf for the year ended December 31, 2008 and $8.339 per Mcf for the year ended December 31, 2007. The price per Mcf was higher for the year ended December 31, 2008 than for the year ended December 31, 2007 due to an increase in the average spot market price for gas delivered at the Henry Hub near Henry, Louisiana ($9.160 per Dth for the year ended December 31, 2008 as compared to $7.281 per Dth for the year ended December 31, 2007).

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 Disclosures About Market Risk.***

The Trust does not engage in any operations and does not utilize market risk sensitive instruments, either for trading purposes or for other than trading purposes. As described 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 Eastern Marketing, a wholly owned subsidiary of ECA pursuant to the Gas Purchase Contract described herein.

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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, Energy Corporation of America ("ECA"), and the independent reserve engineer to The Bank of New York Mellon Trust Company, 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 ECA.

As of December 31, 2009, 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 at a reasonable assurance level.

Due to the contractual arrangements of (i) the Trust Agreement and (ii) the rights of the Trustee under the Conveyances regarding information furnished by ECA, 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:

- ECA 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 Trustee necessarily relies upon the independent reserve engineer, as an expert with respect to the annual reserve report, which includes projected production, operating expenses and capital expenses.

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Other than reviewing the financial and other information provided to the Trust by ECA 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, 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, 2009. The effectiveness of the Trust's internal control over financial reporting as of December 31, 2009 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.

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PART III

Item 10. *Directors, Executive Officers and Corporate Governance.*

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. 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: The Bank of New York Mellon Trust Company, N.A., Trustee of Eastern American Natural Gas Trust, Global Corporate Trust, 919 Congress Avenue Suite 500, 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, 2009, December 31, 2008 and December 31, 2007, The Bank of New York Mellon Trust Company, N.A., as Trustee, received $108,000 annually, as Trustee fees and $507,789, $647,198 and $513,663, 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 and Related Stockholder Matters.*

(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 5% of the Units as of March 1, 2010, except as follows:

Name	Number of Shares	Percent of Class
Lucas Capital Management LLC(1) 2 Bridge Ave. Red Bank NJ 07701	325,425	5.5%
Branzan Investment Advisors, Inc.(2)	336,950	5.7%

(1) Reference is hereby made to the Schedule 13G filed by Lucas Capital Management LLC on January 14, 2010 for information regarding the ownership of the reporting person.

(2) Reference is hereby made to the Schedule 13G filed by Branzan Investment Advisors, Inc. on August 19, 2009 for information regarding the ownership of the reporting person.

(b) Security Ownership of Management.

Not applicable.

(c) Changes in Control.

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.

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

The Trust has no equity compensation plans.

Item 13. *Certain Relationships and Related Transactions, and Director Independence.*

The Trust has no directors. Since January 1, 2009, there has not been, and there is not currently proposed, any transaction or series of similar transactions requiring disclosure under Item 404 of Regulation S-K.

Item 14. *Principal Accounting Fees and Services.*

Audit Fees

The fees 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 $205,000 in 2009 and $210,078 in 2008.

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 $107,250 in 2009 and $103,000 in 2008.

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.

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PART IV

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

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 Exhibits 31, 32 and 99.1, 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) Certification
32	Section 1350 Certification
99.1	Report of Ryder Scott Company L.P. dated February 5, 2010

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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 15th day of March, 2010.

EASTERN AMERICAN NATURAL GAS TRUST

By:	The Bank of New York Mellon Trust Company, 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.

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February 5, 2010

Eastern American Natural Gas Trust
The Bank of New York Mellon Trust Company, N.A.
919 Congress Avenue
Suite 500
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, 2009. 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). As of January 1, 2010 EAEC merged with and into ECA with ECA being the surviving entity and now ECA, by operation of law, is the owner of the underlying properties burdened by the Net Profits Interest owned by the Trust. 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 reserves and future net income amounts presented in this report, as of December 31, 2009 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below

	As of December 31, 2009		
Proved Net Developed	**Gas**	**Estimated Future Net Cash Inflows**	**Present Value At 10%**
	(MMCF)	**(M$)**	**(M$)**
Royalty NPI	8,383	46,418	19,490
Term NPI	2,317	12,830	10,968
Total	10,700	59,248	30,458

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, 2010 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 ECA. 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

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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 ECA will vary in the future as relative estimates of future gross revenues and future net incomes vary. Furthermore, ECA 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 and income data were estimated based on the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations).

Securities and Exchange Commission Regulation S-X §229.4-10(a) (22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

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(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

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, 2009 from this report are presented in the following table:

	As of December 31, 2009		
Total Proved	**Royalty NPI**	**Term NPI**	**Totals**
Future Cash Inflows (M$)	46,418	12,830	59,248
Future Costs			
Production (M$)	0	0	0
Development (M$)	0	0	0
Total Costs (M$)	$ 0	0	0
Future Net Cash Inflows			
Before Income Tax (M$)	46,418	12,830	59,248
Present Value at 10%			
Before Income Tax (M$)	18,308	10,333	28,641

	As of December 31, 2009		
Proved Net Developed Reserves	**Royalty NPI**	**Term NPI**	**Totals**
Gas (MMCF)	8,383	2,317	10,700
Proved Net Undeveloped Reserves			
Gas (MMCF)	0	0	0
Total Proved Net Reserves			
Gas (MMCF)	8,383	2,317	10,700

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.

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This report utilized the terms of the gas contract between Eastern Marketing Corporation (a wholly owned subsidiary of ECA) and the Trust. Gas price is to be determined by a weighted price consisting of two components during a primary term defined to begin on January 1, 1993 and end December 31, 1999. The first component is the "Fixed" price which has been defined as $2.66 per Mcf beginning January 1, 1993. This price escalates 5 percent per year on January 1 of each year during the primary term beginning in 1994. The second component is the "Variable" price which for any quarter is equal to the Henry Hub Average Spot Price (as defined) per MMBtu, plus $0.30 per MMBtu, multiplied by 110 percent to effect a Btu adjustment. The Henry Hub Average Spot Price is defined as the price per MMBtu determined for any calendar quarter as the average price of the three months in such quarter where each month's price is equal to the average of (i) the final settlement prices per MMBtu for Henry Hub Gas Futures Contracts (as defined), as reported in the *Wall Street Journal*, for such contracts which expired in each of the five months prior to each month of such quarter, (ii) the final settlement price per MMBtu for Henry Hub Gas Futures Contracts, as reported in the *Wall Street Journal*, for such contracts which expire during such month and (iii) the closing settlement prices per MMBtu of Henry Hub Gas Futures Contracts for such month, as reported in the *Wall Street Journal*, for such contracts which expire in each of the six months following such month. A Henry Hub Gas Futures Contract is defined as a gas futures contract for gas to be delivered to the Henry Hub which is traded on the New York Mercantile Exchange. The weighted average price is determined by giving the "Fixed" price a $66^2/_3$ percent weighting and the variable price a $33^1/_3$ percent weighting.

Since the primary term is complete, the purchase price under the gas contract will be equal to the "Variable" price. ECA computed the "Variable" price under the gas contract as of December 31, 2009 as $5.537 per Mcf, utilizing $4.731 as the Henry Hub Average Spot Price computed in accordance with the gas contract but utilizing the SEC guidelines that require the price to be based on the 12-month period prior to the ending date of the period covered in this report .

Operating costs for the leases and wells in this report were supplied by ECA 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. ECA 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 August, 2009.

At the time of formation of the Trust, ECA assigned The Trust an interest in 65 undeveloped locations. During the period 1993 through 1998, ECA 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 ECA. Moreover, due to the nature of the Net

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

Estimated Net Reserve Data
Certain Combined Leasehold Interests of
Energy Corporation of America
And The Trust
As of December 31, 2009
SEC Parameters

	Proved		Total
Net Remaining Reserves	**Developed**	**Undeveloped**	**Proved**
Gas-MMCF	29,233	0	29,233

The estimated future net income associated with the foregoing volumes and the 10 percent discounted estimated future net income was $123,220,946 and $50,486,568, 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.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years. Ryder Scott is employee owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any publicly traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Ryder Scott requires that staff engineers and geoscientists have received professional accreditation, and are maintaining in good standing, a registered or certified professional engineer's license or a

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registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization prior to becoming an officer of the Company.

We are independent petroleum engineers with respect to Energy Corporation of America. Neither we nor any of any of our employees have any interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The professional qualifications of the undersigned, the technical person primarily responsible for preparing the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

This report was prepared for the exclusive use and sole benefit of Eastern American Natural Gas Trust and Energy Corporation of America and may not be put to other use without our prior written consent for such use. The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

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

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EASTERN AMERICAN NATURAL GAS TRUST

FINANCIAL STATEMENTS

as of December 31, 2009 and 2008
and for the years ended
December 31, 2009, 2008 and 2007

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Report of Independent Registered Public Accounting Firm

To the Unit Holders of Eastern American Natural Gas Trust and
The Bank of New York Mellon Trust Company, N.A., Trustee

We have audited the accompanying statements of assets, liabilities and trust corpus of Eastern American Natural Gas Trust (the "Trust") as of December 31, 2009 and 2008, and the related statements of distributable income, and statements of changes in trust corpus for each of the three years in the period ended December 31, 2009. We also have audited the Trust's internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Trustee is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the Trustee's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Trust's internal control over financial reporting based on our integrated 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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.

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 company; (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 company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company'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.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Trust at December 31, 2009 and 2008, and the distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2009, on the

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basis of accounting described in Note 2. Also in our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by COSO.

/s/ PricewaterhouseCoopers LLP

Pittsburgh, Pennsylvania
March 12, 2010

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EASTERN AMERICAN NATURAL GAS TRUST

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

as of December 31, 2009 and 2008

	2009	2008
Assets:		
Cash	$ 140,972	$ 121,173
Prepaid Expenses	25,000	
Net Proceeds Receivable	1,774,283	3,383,989
Net Profits Interests in Gas Properties	93,162,180	93,162,180
Accumulated Amortization	(76,467,421)	(74,097,304)
	16,694,759	19,064,876
Total Assets	$ 18,635,014	$ 22,570,038
Liabilities and Trust Corpus:		
Trust General and Administrative Expenses Payable	$ 213,774	$ 286,764
Distributions Payable	1,526,481	3,018,398
Trust Corpus (5,900,000 units authorized and outstanding)	16,894,759	19,264,876
Total Liabilities and Trust Corpus	$ 18,635,014	$ 22,570,038

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

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EASTERN AMERICAN NATURAL GAS TRUST

STATEMENTS OF DISTRIBUTABLE INCOME

for the years ended

December 31, 2009, 2008 and 2007

	2009	2008	2007
Royalty Income	$ 8,868,114	$ 17,028,373	$ 14,660,909
Operating Expenses:			
Taxes on Production and Property	676,110	1,254,139	1,104,557
Operating Cost Charges	685,529	617,564	588,160
Total Operating Expenses	1,361,639	1,871,703	1,692,717
Net Proceeds to the Trust	7,506,475	15,156,670	12,968,192
General and Administrative Expenses	979,925	1,107,022	961,587
Interest Income	47		
Distributable Income	6,526,597	14,049,648	12,006,605
Cash Reserve Refunded (Withheld)			500,000
Distribution Amount	$ 6,526,597	$ 14,049,648	$ 12,506,605
Distributable Income Per Unit (5,900,000 units authorized and outstanding)	$ 1.1062	$ 2.3813	$ 2.0350
Distribution Amount Per Unit (5,900,000 units authorized and outstanding)	$ 1.1062	$ 2.3813	$ 2.1198

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

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EASTERN AMERICAN NATURAL GAS TRUST

STATEMENTS OF CHANGES IN TRUST CORPUS

for the years ended

December 31, 2009, 2008 and 2007

	2009	2008	2007
Trust Corpus, Beginning of Period	$ 19,264,876	$ 21,823,160	$ 25,261,218
Distributable Income	6,526,597	14,049,648	12,006,605
Distributions Paid or Payable to Unitholders	(6,526,597)	(14,049,648)	(12,506,605)
Amortization of Net Profits Interests in Gas Properties	(2,370,117)	(2,558,284)	(2,938,058)
Trust Corpus, End of Period	$ 16,894,759	$ 19,264,876	$ 21,823,160

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 Energy Corporation of America ("ECA"), 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 / Harris Trust, and consequently, The Bank of New York served as trustee of the Trust. 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, effective as of January 1, 2005. Effective October 2, 2006, The Bank of New York Trust Company, N. A. replaced JPMorgan Chase Bank, N.A. as trustee in connection with the sale by JPMorgan Chase Bank of substantially all of its corporate trust business to The Bank of New York. Consequently, references herein to the "Trustee" mean Bank of Montreal Trust Company until May 8, 2000; The Bank of New York as successor Trustee from May 8, 2000 through December 31, 2004; JPMorgan Chase Bank, N.A. as successor trustee, from January 1, 2005 through October 2, 2006; and The Bank of New York, N.A. as successor Trustee (now known as The Bank of New York Mellon Trust Company, N.A.), effective as of October 2, 2006. The transfer agent for the Trust is Bondholder Communications, an affiliate of The Bank of New York Mellon Trust Company, N.A.

The purpose of the Trust is to acquire and hold net profits interests owned by ECA 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 ECA. 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. ECA 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 ECA's net revenue interests in the properties burdened by the Term NPI. As of December 31, 2009, 25,697 MMcf of such gas had been produced.

ECA 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, ECA 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, ECA had a disagreement with the Trust over ECA's obligation to drill these closely offset development wells. The Trust agreed that, in lieu of drilling these closely offset development wells ECA 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.

EASTERN AMERICAN NATURAL GAS TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

1. *Organization of the Trust*: (Continued)

The two (2) remaining development wells were not drilled because ECA was unable to cure various title defects associated with these wells. ECA 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 ECA under the Reasonably Prudent Operator Standard then such drill site(s) shall be construed as a development well(s). Consequently, ECA 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 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 ECA 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.

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.

Most accounting pronouncements apply to entities whose financial statements are prepared in accordance with U.S. generally accepted accounting principles. Because the Trust's financial statements are prepared on a comprehensive basis of accounting other than U.S. generally accepted accounting

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EASTERN AMERICAN NATURAL GAS TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

2. *Significant Accounting Policies*: (Continued)

principles, as described above, most accounting pronouncements are not applicable to the trust's financial statements.

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 assessed to determine whether their net capitalized cost is impaired, whenever events or changes in circumstances indicate that its carrying amount may not be recoverable, pursuant to ASC 360. 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 fair value of the investment in net profits interests attributable to proved gas reserves of the Underlying Properties. Any such writedown would not reduce Distributable Income, although it would reduce Trust Corpus. No impairment in the Underlying Properties was recognized during the three and twelve month periods ended December 31, 2009.

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 Property and 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 ("Eastern Marketing"), a wholly owned subsidiary of ECA, require payment with respect to gas

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EASTERN AMERICAN NATURAL GAS TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

2. *Significant Accounting Policies*: (Continued)

production for a calendar quarter to be made to the Trust on or before the tenth day of the third month following such quarter.

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. The estimates include an estimate of the revenues attributable to the Trust from natural gas production for the last several months of the year, as the revenues from natural gas sales are typically received several months after delivery. Actual results could differ from those estimates.

Segment 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. *Effects of New Pronouncements*:

In January 2009, the SEC published its final rule regarding the modernization of oil and gas reporting, which modifies the SEC's reporting and disclosure rules for oil and gas reserves. The most notable changes of the final rule include the replacement of the single day period-end pricing to value natural gas and oil reserves to a 12-month average of the first day of the month price for each month within the reporting period. The final rule also permits voluntary disclosure of probable and possible reserves, disclosure previously prohibited by SEC rules. The revised reporting and disclosure requirements were effective for us as of December 31, 2009. Early adoption was not permitted.

In January 2010, the FASB issued changes in its oil and gas reserve estimation and disclosure requirements to align them with the SEC's final rule discussed above. These changes were also effective for us as of December 31, 2009.

We applied the above changes to our financial statements as of and for the year ended December 31, 2009. The impact of the adoption of the SEC final rule on our financial statements is not practicable to estimate due to the operational and technical challenges associated with calculating a cumulative effect of adoption by preparing reserve reports under both the old and new rules.

In May 2009, the Financial Accounting Standards Board (FASB) issued FASB ASC 855, *Subsequent Events* ("ASC 855"). ASC 855 establishes principles and standards related to the accounting for and disclosure of events that occur after the date of the balance sheet included in financial statements being presented, but before such financial statements are issued. ASC 855 requires an entity to recognize, in the financial statements, subsequent events that provide additional information regarding conditions that existed at the balance sheet date. Subsequent events that provide information about conditions that did not exist at the balance sheet date are not to be recognized in the financial statements under ASC 855. ASC 855 is effective for interim and annual reporting periods ending after June 15, 2009. The Trust adopted this standard effective as of June 30, 2009. The adoption of ASC 855 did not have a material effect on the Trust's financial statements.

In June 2009, the FASB issued a statement that establishes the FASB Accounting Standards Codification as the source of authoritative U.S. generally accepted accounting principles (U.S. GAAP).

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EASTERN AMERICAN NATURAL GAS TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

3. *Effects of New Pronouncements*: (Continued)

The Codification, which changes the referencing of financial standards, became effective for our third quarter 2009 financial statements and did not have an impact on the Trust's financial statements. The Codification did not change or alter existing U.S. GAAP.

4. *Income Taxes*:

Tax counsel to ECA advised ECA 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.

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.

5. *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 ECA 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, 2009 are expected to be received by the Trust and distributed to the Unitholders on March 15, 2010. The December 31, 2008 Net Proceeds Receivable were received and distributed by the Trust on March 13, 2009.

6. *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 $615,789 for the year ended December 31, 2009, $755,198 for the year ended December 31, 2008 and $621,663 for the year ended December 31, 2007. 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 ECA for overhead expenses. The initial fee

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EASTERN AMERICAN NATURAL GAS TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

6. *Related Party Transactions*: (Continued)

at the inception of the Trust was $210,000. The Trustee paid ECA $364,136, $351,824 and $339,924 for overhead expenses for 2009, 2008 and 2007, respectively. Operating Cost Charges included in the Statements of Distributable Income are paid to ECA.

Gas production attributable to the Net Profits Interests is purchased from the Trust by Eastern Marketing Corporation 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, ECA has agreed to make payments under the Gas Purchase Contract to the extent such payments are not made by Eastern Marketing.

7. *Subsequent Events*:

Management evaluated all activity of the Trust through the date of the filing of these financial statements and concluded that no subsequent events have occurred that would require recognition in the Financial Statements or disclosure in the Notes to the Financial Statements except as follows:

The Trust was formed under the Delaware Business Trust Act pursuant to a Trust Agreement (the "Trust Agreement") among Eastern American Energy Corporation, as grantor, Bank of Montreal Trust Company, as trustee, and Wilmington Trust Company, as Delaware Trustee (the "Delaware Trustee"). Until January 1, 2010, Eastern American Energy Corporation was a wholly-owned subsidiary of Energy Corporation of America. Effective January 1, 2010, Eastern American Energy Corporation was merged into Energy Corporation of America, with Energy Corporation of America being the surviving corporation. The merger of Eastern American Energy Corporation into its parent Energy Corporation of America is not expected to have any significant effect on the Trust.

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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, Ryder Scott. 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 ECA 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% 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 ECA. 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 ECA 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, 2007 to December 31, 2009:

	Royalty NPI (MMcf)	**Term NPI (MMcf)**	**Total NPI (MMcf)**
Balance, January 1, 2007	9,885	4,814	14,699
Production	(774)	(984)	(1,758)
Revisions of previous estimates	901	(5)	896
Balance, December 31, 2007	10,012	3,825	13,837
Production	(707)	(930)	(1,637)
Revisions of previous estimates	530	179	709
Balance, December 31, 2008	9,835	3,074	12,909
Production	(694)	(911)	(1,605)
Revisions of previous estimates	(758)	154	(604)
Balance, December 31, 2009	8,383	2,317	10,700

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

	Royalty NPI (MMcf)	Term NPI (MMcf)	Total NPI (MMcf)
December 31, 2007	10,012	3,825	13,837
December 31, 2008	9,835	3,074	12,909
December 31, 2009	8,383	2,317	10,700

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, 2009 (in thousands):

	Royalty NPI	Term NPI	Total NPI
Future cash inflows	$ 61,761	$ 15,072	$ 76,833
Future production taxes	(2,982)	(644)	(3,626)
Future production costs	(12,361)	(1,598)	(13,959)
Future net cash inflows	46,418	12,830	59,248
10% discount factor	(26,918)	(1,862)	(28,790)
Standardized measure of discounted future net cash flows	$ 19,490	$ 10,968	$ 30,458

The following is the standardized measure of discounted future net cash flows as of December 31, 2008 (in thousands):

	Royalty NPI	Term NPI	Total NPI
Future cash inflows	$ 112,434	$ 33,015	$ 145,449
Future production taxes	(5,079)	(1,341)	(6,420)
Future production costs	(13,734)	(2,417)	(16,151)
Future net cash inflows	93,621	29,257	122,878
10% discount factor	(55,987)	(5,300)	(61,287)
Standardized measure of discounted future net cash flows	$ 37,634	$ 23,957	$ 61,591

The following is the standardized measure of discounted future net cash flows as of December 31, 2007 (in thousands):

	Royalty NPI	Term NPI	Total NPI
Future cash inflows	$ 99,875	$ 35,706	$ 135,581
Future production taxes	(4,548)	(1,475)	(6,023)
Future production costs	(12,829)	(2,711)	(15,540)
Future net cash inflows	82,498	31,520	114,018
10% discount factor	(48,771)	(6,733)	(55,504)
Standardized measure of discounted future net cash flows	$ 33,727	$ 24,787	$ 58,514

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Changes in Standardized Measure of Discounted Future Net Cash Flows:

The following schedule reconciles the changes during 2007, 2008 and 2009 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, 2007	$ 33,779	$ 29,481	$ 63,260
Net proceeds to the Trust	(9,383)	(3,585)	(12,968)
Revisions of previous estimates	3,810	(21)	3,789
Accretion of discount	3,378	2,948	6,326
Net change in price and production costs	(682)	(287)	(969)
Other	2,825	(3,749)	(924)
Standardized measure, December 31, 2007	$ 33,727	$ 24,787	$ 58,514
Net proceeds to the Trust	(11,548)	(3,609)	(15,157)
Revisions of previous estimates	2,529	854	3,383
Accretion of discount	3,372	2,479	5,851
Net change in price and production costs	5,047	1,570	6,617
Other	4,507	(2,124)	2,383
Standardized measure, December 31, 2008	$ 37,634	$ 23,957	$ 61,591
Net proceeds to the Trust	(5,881)	(1,625)	(7,506)
Revisions of previous estimates	(2,157)	438	(1,719)
Accretion of discount	3,763	2,396	6,159
Net change in price and production costs	(17,593)	(4,164)	(21,756)
Other	3,724	(10,034)	(6,309)
Standardized measure, December 31, 2009	$ 19,490	$ 10,968	$ 30,458

Quarterly Financial Data (Unaudited):

The following is a summary of royalty income and distributable income per unit by quarter in 2009, 2008 and 2007 (all amounts in thousands except Distributable income per unit):

2009	**Mar 31**	**June 30**	**Sept 30**	**Dec 31**	**Total**
Royalty Income	$ 2,666	$ 2,055	$ 2,040	$ 2,107	$ 8,868
Distributable Income	$ 1,953	$ 1,484	$ 1,563	$ 1,527	$ 6,527
Distributable Income Per Unit	$ 0.3312	$ 0.2515	$ 0.2648	$ 0.2587	$ 1.0162

2008	**Mar 31**	**June 30**	**Sept 30**	**Dec 31**	**Total**
Royalty Income	$ 3,548	$ 4,679	$ 4,980	$ 3,821	$ 17,028
Distributable Income	$ 2,773	$ 3,957	$ 4,302	$ 3,018	$ 14,050
Distributable Income Per Unit	$ 0.4700	$ 0.6706	$ 0.7291	$ 0.5116	$ 2.3813

2007	**Mar 31**	**June 30**	**Sept 30**	**Dec 31**	**Total**
Royalty Income	$ 3,565	$ 3,855	$ 3,694	$ 3,547	$ 14,661
Distributable Income	$ 2,832	$ 3,144	$ 3,084	$ 2,947	$ 12,007
Distributable Income Per Unit	$ 0.4800	$ 0.5328	$ 0.5228	$ 0.4995	$ 2.0350