LONG ISLAND POWER AUTHORITY
(A Component Unit of the State of New York)

Basic Financial Statements

December 31, 2010 and 2009

(With Independent Auditors' Report Thereon)

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KPMG LLP
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Independent Auditors' Report

The Board of Trustees
Long Island Power Authority:

We have audited the balance sheets, statements of revenues, expenses, and changes in net assets, and statements of cash flows of the Long Island Power Authority (Authority), a component unit of the State of New York, as of and for the years then ended December 31, 2010 and 2009, which collectively comprise the Authority's basic financial statements. These financial statements are the responsibility of the Authority's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Authority as of December 31, 2010 and 2009, and the changes in its financial position and its cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

As described in note 4 to the financial statements, the Authority adopted the provisions of Governmental Accounting Standards Board (GASB) Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments*, as of January 1, 2009.

In accordance with *Government Auditing Standards*, we have also issued a report dated March 31, 2011, on our consideration of the Authority's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is to describe the scope and of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be considered in assessing the results of our audit.

The accompanying management's discussion and analysis listed in the accompanying table of contents is not a required part of the basic financial statements but is supplementary information required by U.S. generally accepted accounting principles. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

KPMG LLP

March 31, 2011

Overview of the Financial Statements

This report consists of three parts: management's discussion and analysis (unaudited), the basic financial statements, and the notes to the financial statements.

The financial statements provide summary information about the Authority's overall financial condition. The notes provide explanation and more details about the contents of the financial statements.

The Authority is considered a special-purpose government entity engaged in business-type activities and follows financial reporting for enterprise funds. The Authority's financial statements are prepared in accordance with generally accepted accounting principles (GAAP) as prescribed by the Governmental Accounting Standards Board (GASB). In accordance with GASB standards, the Authority has elected to comply with all authoritative pronouncements applicable to nongovernmental entities (i.e., pronouncements of the Financial Accounting Standards Board) that do not conflict with GASB pronouncements.

Management's Discussion and Analysis (Unaudited)

The management's discussion and analysis of the Authority's financial performance provides an overview of the Authority's financial information for the years ended December 31, 2010 and 2009. The discussion and analysis should be read in conjunction with the financial statements and accompanying notes, which follow this section.

The Authority complies with all applicable pronouncements of the Governmental Accounting Standards Board (GASB). In accordance with GASB Statement No. 20, *Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities That Use Proprietary Fund Accounting*, the Authority complies with all authoritative pronouncements applicable to nongovernmental entities (i.e., pronouncements of the Financial Accounting Standards Board) that do not conflict with GASB pronouncements. In June 2008, GASB issued Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments*. This statement requires that the fair value of financial arrangements called "derivatives" or "derivative instruments" be reported in the financial statements of state and local governments. GASB No. 53 became effective for the Authority beginning in 2010 and required retroactive application. The implementation resulted in reclassifications and adjustments to prior period amounts.

The operations of the Authority are presented as an enterprise fund following the accrual basis of accounting in order to recognize the flow of economic resources. Under this basis, revenues are recognized in the period in which they are earned and expenses are recognized in the period in which they are incurred.

The Authority is subject to the provisions of FASB ASC 980 *Regulated Operations* (previously SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*). This statement recognizes the economic impact of regulation, through the ratemaking process, to create future economic benefits and obligations affecting rate-regulated companies. Accordingly, the Authority records these future economic benefits and obligations as regulatory assets and regulatory liabilities, respectively.

(Continued)

The following is a summary of the Authority's financial information for 2010, 2009, and 2008 (amounts in thousands):

Balance Sheet Summary

		December 31,	
	2010	**2009**	**2008**
Assets:			
Current assets:			
Cash, cash equivalents and investments	$ 479,026	495,547	257,720
Other current assets	927,957	682,583	725,269
Noncurrent assets:			
Utility plant, net	6,431,896	6,459,718	5,725,010
Promissory notes receivable	155,425	155,425	155,425
Nonutility property and other investments	80,703	74,679	71,753
Deferred charges and long-term receivables	301,044	291,520	584,360
Regulatory assets	730,490	789,279	1,097,230
Acquisition adjustment, net	2,487,366	2,629,216	2,741,897
Total assets	$ 11,593,907	11,577,967	11,358,664
Liabilities and net assets:			
Regulatory liability	$ 192,992	164,520	2,483
Other current liabilities	1,213,524	1,168,720	1,196,538
Noncurrent liabilities:			
Long-term debt	6,363,244	6,394,949	6,394,364
Capital lease obligations	2,834,416	2,970,126	2,369,168
Regulatory liability	74,085	—	—
Other noncurrent liabilities	405,453	356,295	310,187
Deferred credits	133,024	203,637	796,746
Total liabilities	11,216,738	11,258,247	11,069,486
Net assets (deficit):			
Capital assets net of related debt	(87,016)	(171,412)	(56,269)
Restricted	365	46,340	229,285
Unrestricted	463,820	444,792	116,162
Total net assets	377,169	319,720	289,178
Total liabilities and net assets	$ 11,593,907	11,577,967	11,358,664

Summary of Revenues, Expenses, and Changes in Net Assets

		Year ended December 31,		
		2010	**2009**	**2008**
Electric revenue	$	3,859,549	3,312,160	3,751,610
Operating expenses:				
Operations – fuel and purchased power		1,879,839	1,566,005	2,164,658
Operations and maintenance		1,129,931	864,576	785,342
General and administrative		41,852	40,153	31,347
Depreciation and amortization		251,117	254,944	246,919
Payments in lieu of taxes		281,609	249,652	239,659
Total operating expenses		3,584,348	2,975,330	3,467,925
Operating income		275,201	336,830	283,685
Other income, net		46,445	33,519	69,862
Grant income		66,294	—	—
Interest charges		(330,491)	(331,899)	(323,365)
Change in net assets before extraordinary loss		57,449	38,450	30,182
Extraordinary loss on early extinguishment of debt		—	—	(3,840)
Change in net assets		57,449	38,450	26,342
Net assets – beginning of year		319,720	289,178	262,836
Cumulative effect of a change in accounting principle		—	(7,908)	—
Net assets – end of year	$	377,169	319,720	289,178

Excess of Revenues over Expenses

The revenues in excess of expenses for the years ended December 31, 2010, 2009 and 2008 totaled approximately $57 million, which includes an adjustment to net assets of $72 million (discussed below), $39 million and $26 million, respectively.

Revenues

Effective January 2010, the Authority changed its accounting methodology used to estimate unbilled energy deliveries and the related customer receivables. This change is needed to more accurately estimate power delivered to customers from the date of their last billing to the end of the accounting period. The unbilled revenue represents an estimate of customer usage during this period. This change in how unbilled revenue is estimated does not impact reported total operating cash flows for any historical period. The change would have increased unbilled revenues, accounts receivable and would also revise reported changes in net assets. This change was adopted after an extensive analysis of the prior methodology. The prior methodology based the estimate of unbilled sales on several factors including electrical usage, seasonal factors, rate differentials and line losses. LIPA has determined that a more accurate and appropriate method is to accrue unbilled revenues by estimating unbilled consumption at the customer meter.

The net impact of this change results in an increase of net assets of approximately $72 million, $62 million which resulted from increased sales and approximately $10 million of which is due to reduced acquisition adjustment amortization related to a change to a reserve acquired from LILCO in 1998.

When this change was implemented effective January 2010, it resulted in: (i) an increase of estimated unbilled receivables of approximately $231 million; (ii) the establishment of a regulatory liability of approximately $129 million to reflect the amount of revenue deferred that will returned to customers in accordance with the operation of the fuel and purchased power cost adjustment (FPPCA); (iii) a $30 million decrease in the unamortized balance of the acquisition adjustment related to a reserve acquired from LILCO; and (iv) the $72 million increase in net assets (noted above).

Revenue for the twelve months ended December 31, 2010 increased approximately $547 million when compared to the similar period of 2009. This increase is primarily attributable to higher sales-driven recoveries of power supply costs totaling $184 million, the positive effects of weather totaling $113 million, higher average customer usage totaling approximately $32 million and an adjustment of $5 million related to a settlement of a long standing dispute with a commercial customer. In addition, effective January 1, 2010, the Authority implemented two new cost recovery mechanisms, the New York State Assessment and the Energy Efficiency Cost Recovery Rate, which positively impacted revenues by $124 million. Also impacting revenue was the change in the method for unbilled receivables (discussed above) totaling $62 million. Furthermore, despite the reduction in the FPPCA rate effective June 1, 2010, approximately $136 million of power supply recovery revenues were collected that exceeded actual fuel and purchased power supply costs incurred. This over-recovery has been deferred for return to the customer through the reduced FPPCA rate effective January 1, 2011.

Revenue for the twelve months ended December 31, 2009 decreased approximately $439 million when compared to the similar period of 2008. This decrease is primarily attributable to lower recoveries of power supply costs totaling $369 million, the negative effects of weather totaling $34 million, and lower average customer usage totaling approximately $36 million. Despite the reduction in the FPPCA rate effective May 1, 2009 and the one-time bill credits issued totaling approximately $143 million, approximately $164 million of power supply recovery revenues were collected that exceeded actual fuel and purchased power supply costs incurred for the year ended December 31, 2009. The over-recovery was deferred and returned to the customer through the reduced FPPCA rate effective January 1, 2010.

Fuel and Purchased Power Costs

The Authority's tariff includes a power supply costs recovery provision – the Fuel and Purchased Power Cost Adjustment (FPPCA) that provides for the amount and timing of fuel and purchased power cost recoveries.

For the year ended December 31, 2010, fuel and purchased power costs increased by $314 million. LIPA experienced higher commodity costs of $146 million, higher consumption due to sales volumes totaling $113 million, higher amortization of prior year fuel deferrals totaling $3 million and the lower amortization of customer bill credits that resulted in a variance of an additional $52 million when compared to 2009.

(Continued)

For the year ended December 31, 2009, fuel and purchased power costs decreased by $599 million. LIPA experienced lower commodity costs of $611 million, lower consumption due to sales volumes totaling $68 million and the higher amortization of customer bill credits that reduced expense by an additional $64 million when compared to 2008.

Operations and Maintenance Expense (O&M)

Operations and maintenance (O&M) expense for the year ended December 31, 2010 increased $265 million due primarily to higher storm restoration costs totaling $167 million (excluding FEMA reimbursements of $57 million for qualified storms which are included in Grant Income), higher energy efficiency and renewable costs totaling $20 million, higher NYS assessment charges totaling $45 million, higher Management Services Agreement (MSA) costs totaling $13 million (due to higher sales), and higher scheduled costs related to the Power Supply Agreement (PSA) totaling $19 million. O&M expense includes property taxes on the National Grid generating facilities paid by the Authority as a component of the PSA capacity charge which totaled approximately $181 million and $173 million for the years ended December 31, 2010 and 2009, respectively.

O&M expense for the year ended December 31, 2009 increased $79 million due to higher Power Supply Agreement (PSA) capacity charge billings totaling $39 million, higher energy efficiency and renewable costs totaling $25 million, higher storm restoration costs totaling $13 million, higher charge-offs of bad debt accounts totaling $9 million and higher Nine Mile Point 2 costs totaling $2 million. These increases were partially offset by $4 million due to the scheduled increase in the synergy savings credits from National Grid, lower asset retirement accretion expense of $3 million due to a revised Nine Mile Point 2 decommissioning study and $2 million due to the elimination of postage paid envelopes.

General and Administrative Expenses (G&A)

General and administrative expenses for the year ended December 31, 2010 increased by $2 million primarily due to higher pension costs attributable to early retirement incentive provided in 2010.

General and administrative expenses for the year ended December 31, 2009 increased by $9 million partially attributable to an adjustment in 2008 related to injuries and damages reserve that resulted in a $3 million credit in 2008. Also contributing to the increase is higher employee benefit costs totaling $1 million and higher advertising and consulting costs totaling $5 million due to various new projects.

Depreciation and Amortization

Depreciation and amortization for the year ended December 31, 2010 decreased by $4 million. The acquisition adjustment recorded from the LILCO acquisition in 1998 was decreased to reflect the true-up resulting from the unbilled revenue change discussed above. This decrease in the acquisition premium resulted in a reduction of the amortization expense of approximately $10 million. This decrease was partially offset by $6 million of increased depreciation expense as a result of the increased investment in the transmission and distribution system.

For the year ended December 31, 2009, depreciation and amortization increased approximately $8 million, due to higher utility plant balances.

Payments in Lieu of Taxes

For the year ended December 31, 2010 payments in lieu of taxes (PILOTs) increased approximately $32 million due to higher property taxes on the transmission and distribution assets totaling $23 million and higher revenue based taxes (due to higher sales in 2010) totaling $9 million.

For the year ended December 31, 2009 PILOTS increased $10 million due to higher property taxes on the transmission and distribution assets.

Other Income, Net

Other income increased approximately $13 million for the year ended December 31, 2010, when compared to the year ended December 31, 2009, as a result of: (i) higher earnings on the Authority's NMP2 trust account totaling $3 million partially offset by lower investment earnings of $1 million; (ii) the recognition of $6 million related to previously deferred receipts that were deemed Nonrefundable; and (iii) the absence of miscellaneous expenses totaling $5 million (due to the Board approved costs related to community benefits packages paid in 2009).

Other income decreased approximately $36 million for the year ended December 31, 2009, when compared to the year ended December 31, 2008, as a result of lower investment earnings totaling $19 million due to lower average cash balances and lower interest rates, lower sales of emissions allowance credits totaling $4 million and higher miscellaneous expenses totaling $6 million (due to the Board approved costs related to community benefits packages). In addition, in 2008 LIPA recognized $7 million of nonrecurring income related to an interest rate swap that was terminated.

Grant Income

In March 2010, Long Island experienced a severe storm causing damage to the transmission and distribution system. As a result of damage, the Federal Emergency Management Agency (FEMA) declared Long Island an Emergency Disaster Area which entitled LIPA to a reimbursement of approximately 75% of the repair costs. The Authority recorded as grant income approximately $54 million related to that reimbursement. An additional $3 million FEMA recovery was recorded as grant income related to a 2009 storm event.

In May 2010, LIPA issued Electric System General Revenue Bonds, Series 2010B which are taxable Build America Bonds. LIPA receives an interest subsidy from the federal government equal to 35% of the interest paid. LIPA recognized as grant income approximately $3 million in subsidies for these Bonds.

The Authority also received a $6 million energy efficiency and renewable energy grant from New York State Energy Research Development Authority (NYSERDA) under its Regional Greenhouse Gas Initiative Program. LIPA participates in an agreement to reduce greenhouse gas emissions from its contracted power plants. The monies paid to NYSERDA by the participants are used to fund energy efficiency programs throughout New York.

Interest Charges and Credits

For the year ended December 31, 2010, total interest charges decreased approximately $1 million attributable to a lower interest rates on variable rate debt and lower outstanding debt balances.

For the year ended December 31, 2009, total interest charges increased approximately $6 million due to higher debt balances outstanding and higher interest rates on the fixed rate debt which refunded variable rate securities.

Cash, Cash Equivalents, and Investments

The Authority's cash, cash equivalents, and investments totaled approximately $479 million, $496 million, and $258 million at December 31, 2010, 2009, and 2008, respectively. The decrease from 2009 to 2010 is primarily due to higher debt maturities than bond issuances during 2010. The increase from 2008 to 2009 is due to the fuel and purchased power supply costs recovered in excess of that incurred and the lower counterparty collateral postings required. The Authority also has the authorization to issue up to $300 million of commercial paper notes, $200 million of which were outstanding at December 31, 2010, 2009 and 2008.

Capital Assets

The Authority continued its investment in transmission and distribution (T&D) upgrades to manage reliability and to enhance capacity needed to meet anticipated customer demands. For the years ended December 31, 2010 and 2009, capital improvements to the T&D system totaled approximately $208 million and approximately $229 million, respectively. These improvements included interconnection equipment, the replacement or upgrade of transformer banks and circuit breakers, new substations, enhanced transmission lines and upgraded command and control equipment.

Regulatory Assets

Regulatory assets decreased approximately $59 million during the year ended December 31, 2010. The decrease is the result of: (i) the recovery of the 2003 deferred excess fuel and purchased power costs totaling approximately $38 million, scheduled to be recovered over a ten-year period which began January 1, 2004, in accordance with the Authority's tariff; (ii) the recovery of the New York State special assessment totaling $45 million; (iii) the scheduled recovery of approximately $41 million related to the Shoreham Property Tax Settlement Agreement through a surcharge on billings for electric service to customers residing in Suffolk County (the Shoreham surcharge), which began in 2003 (as discussed in greater detail in note 3 to the financial statements); and (iv) the amortization of deferred interconnection facility costs totaling $2 million. These decreases were partially offset by: (i) carrying charges of $31 million on the Shoreham Property Tax Settlement Agreement related credits for the year; and (ii) the deferral of the 2010 special assessment paid to New York State (NYS) totaling $36 million.

Regulatory assets decreased approximately $128 million from December 31, 2008 to December 31, 2009. The decrease is the result of: (i) the negative mark-to-market valuation on the Authority's fuel and purchased power derivatives totaling approximately $137 million; (ii) the recovery of the 2003 deferred excess fuel and purchased power costs totaling approximately $35 million, scheduled to be recovered over a ten-year period which began January 1, 2004, in accordance with the Authority's tariff; and (iii) the scheduled recovery of approximately $36 million related to the Shoreham Property Tax Settlement Agreement through a surcharge on billings for electric service to customers residing in Suffolk County (the Shoreham surcharge), which began in 2003 (as discussed in greater detail in note 3 to the financial statements). These decreases were partially offset by: (i) carrying charges on the Shoreham Property Tax Settlement Agreement related credits totaling approximately $31 million for the year; (ii) the deferral of the 2009 NYS special assessment totaling $37 million (since LIPA's rates did not include the recovery until 2010, the 2009 assessment was deferred to be collected ratably from ratepayers over the next four years); and (iii) approximately $12 million of incremental costs associated with the Southampton Visual Benefits Assessment (VBA) Agreement between the Authority and the Town of Southampton (Town). In May 2008, the Authority and the Town reached an agreement allowing the Authority to collect over a 20-year period any incremental costs (plus interest) associated with installing an underground transmission line.

Regulatory Liabilities

For the year ended December 31, 2010, the regulatory liabilities increased by approximately $102 million resulting primarily from (i) the establishment of a regulatory liability totaling $129 million resulting from the revised unbilled receivable estimate; (ii) the excess recovery of fuel and purchased power supply costs recovered totaling $136 million which will be returned to customers through reductions in the FPPCA in 2011; and (iii) the excess collection of the 2010 efficiency and renewable charge totaling $11 million. These increases were partially offset by the return of the 2009 excess recovery of fuel and purchased power supply costs totaling $174 million.

For the year ended December 31, 2009, the regulatory liabilities increased by approximately $162 million resulting primarily from the fuel and purchased power supply costs recovered in excess of costs incurred which was returned to customers through reductions in the FPPCA in 2010.

Debt

The Authority's debt, including current maturities, is comprised of the following instruments (amounts in thousands):

	Balance at December 31,		
	2010	2009	2008
General Revenue Bonds	$ 5,945,934	5,924,664	5,722,633
Subordinated Revenue Bonds	551,450	576,705	785,825
Commercial Paper Notes	200,000	200,000	200,000
NYSERDA Notes	155,420	155,420	155,420
	$ 6,852,804	6,856,789	6,863,878

During 2010, debt decreased approximately $4 million resulting from scheduled maturities of approximately $225 million and the refunding of $212 million outstanding insured variable rate debt. This was partially offset by: (i) the issuance of Electric System General Revenue Bonds Series 2010A totaling approximately $193 million (plus premium of approximately $20 million) which was used for the purpose of the $212 million refunding; (ii) the issuance of the Electric System General Revenue Bonds Series 2010B totaling $210 million which will be used to finance the Authority's on going capital improvements program; and (iii) the accretion of the capital appreciation bonds totaling approximately $30 million.

During 2009, debt decreased approximately $7 million resulting from scheduled maturities of approximately $242 million and the refunding of $231 million outstanding insured variable rate debt. This was partially offset by: (i) the issuance of Electric System General Revenue Bonds Series 2009A totaling approximately

$436 million which was used for the purpose of the refunding and the remainder used to finance the Authority's on-going capital improvements program; and (ii) the accretion of the capital appreciation bonds totaling approximately $30 million.

For a full discussion on the Authority's refunding activities during 2010 and 2009, see note 9 to the financial statements.

Risk Management

The Authority is routinely exposed to commodity and interest rate risk. In order to attempt to mitigate such exposure, the Authority formed an Executive Risk Management Committee to strengthen executive management oversight for the risk mitigation activities of the Authority. In addition, the Authority retains an external consultant specializing in risk management, energy markets and energy trading to enhance the Authority's understanding of these areas.

The risk management program is intended to identify exposures to movements in fuel and purchased power prices, quantify the impact of these exposures on the Authority's financial position, liquidity and the FPPCA and attempts to mitigate the exposures in line with the Authority's identified levels of risk tolerance. The Authority actively manages the program in both upward and downward trending markets and adjusts its positions as necessary in an attempt to mitigate the impact of potentially unfavorable market movements. At December 31, 2010, 2009 and 2008 the Authority had posted approximately $365,000, $46 million, and $229 million, respectively, of collateral to its counterparties in connection with its energy commodity hedge positions. No collateral was held by or posted by the Authority with respect to its interest rate derivatives.

In accordance with GASB Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments*, the Authority records its hedging and investment derivatives at fair value and records deferred inflows and outflows for changes in fair values on hedging derivatives and defers as unrealized gains and losses changes in fair value for investing derivatives in accordance with its rate making practices. For a further discussion on these matters, see note 4 of the financial statements.

Fuel and purchased power transactions – For the year ended December 31, 2010, the Authority had realized losses of $169 million and recognized $5 million of option premium amortization which increased fuel and purchased power costs by $174 million. The Authority also recorded deferred outflow (unrealized loss) and deferred charges on commodity derivatives of approximately $123 million, reflecting the negative mark-to-market on the Authority's fuel derivative positions. For the year ended December 31, 2009, the Authority had realized losses of $106 million and recognized $38 million of option premium amortization which increased fuel and purchased power costs by $144 million. The Authority also recorded a deferred outflow (unrealized loss) on commodity derivatives of approximately $180 million, reflecting the negative mark-to-market on the Authority's fuel derivative positions.

Interest rate transactions – At December 31, 2010 and 2009, the Authority recorded deferred outflows of $85 million and $67 million, respectively, related to its interest rate hedging derivatives. The Authority also recorded net unrealized fair value losses on its investment derivatives of approximately $154 million and $72 million, respectively. Any gains or losses resulting from changes in the mark-to-market valuations on investment derivatives are deferred, and will be recognized when realized consistent with FASB ASC 980 *Regulated Operations* (previously SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*).

Power Supply

The Authority has entered into numerous agreements for capacity and energy necessary to continue to satisfy the energy demand of Long Island, while increasing the diversity of its fuel mix alternatives.

For additional information on power purchase agreements and its related accounting treatments, see notes 3 and 12 to the financial statements.

Investment Ratings

Below are the Authority's securities as rated by Moody's Investors Service (Moody's), Standard and Poor's Ratings Services (S&P), and Fitch Ratings (Fitch):

	Investment ratings		
	Moody's	**S&P**	**Fitch**
Senior Lien debt	A3	A-	A

Certain Senior and all Subordinated Lien debt and the Commercial Paper notes are supported by either a Letter of Credit (LOC) or are insured against default. Such debt carries the higher of the ratings of the credit support provider (LOC bank or insurance company), or that of the Authority.

Contacting the Long Island Power Authority

This financial report is designed to provide our bondholders, customers, and other interested parties with a general overview of the Authority's finances and to demonstrate its accountability for the funds it receives. If you have any questions about this report or need additional information, contact the Authority at 333 Earle Ovington Blvd., Suite 403, Uniondale, New York 11553, or visit our website at www.lipower.org.

LONG ISLAND POWER AUTHORITY
(A Component Unit of the State of New York)

Balance Sheets

December 31, 2010 and 2009

(Dollars in thousands)

Assets and Deferred Outflows		**2010**	**2009**
Current assets and deferred outflows:			
Cash and cash equivalents	$	363,319	371,264
Investments		115,707	124,283
Counterparty collateral – posted by the Authority		365	46,340
Accounts receivable (net of allowance for doubtful accounts of $32,519, at December 31, 2010 and 2009)		565,339	246,670
Other accounts receivable		80,617	104,872
Fuel inventory		167,630	156,029
Deferred charges		2,744	2,372
Deferred outflow – commodity derivatives		90,341	110,556
Material and supplies inventory		7,432	8,276
Interest receivable		22	28
Prepayments and other current assets		13,467	7,440
Total current assets and deferred outflows		1,406,983	1,178,130
Noncurrent assets and deferred outflows:			
Utility plant and property and equipment, net		6,431,896	6,459,718
Promissory notes receivable – KeySpan Energy		155,425	155,425
Nonutility property and other investments		80,703	74,679
Other long term receivables		65,145	72,657
Deferred outflow – commodity derivatives		24,098	65,782
Deferred outflow – financial derivatives		81,729	66,705
Deferred charges		130,072	86,376
Regulatory assets:			
New York State assessment		27,788	37,040
Southampton visual benefit assessment		11,900	12,070
Shoreham property tax settlement		542,798	552,929
Fuel and purchased power costs recoverable		148,004	187,240
Acquisition adjustment (net of accumulated amortization of $1,577,670 and $1,466,296, respectively)		2,487,366	2,629,216
Total noncurrent assets and deferred outflows		10,186,924	10,399,837
Total assets and deferred outflows	$	11,593,907	11,577,967

See accompanying notes to basic financial statements.

Liabilities and Net Assets		2010	2009
Current liabilities:			
Short-term debt	$	200,000	200,000
Current maturities of long-term debt		238,100	224,960
Current portion of capital lease obligations		135,710	127,953
Accounts payable and accrued expenses		362,820	362,384
Regulatory liabilities:			
Fuel and purchased power costs refundable		181,884	164,520
Energy efficiency cost recovery variances		11,108	—
Commodity derivative instruments		93,086	112,928
Accrued payments in lieu of taxes		46,389	41,091
Accrued interest		53,616	52,642
Customer deposits		28,701	28,103
Claims and damages due within one year		55,102	18,659
Total current liabilities		1,406,516	1,333,240
Noncurrent liabilities:			
Long-term debt		6,363,244	6,394,949
Borrowings		110,297	114,520
Commodity derivative instruments		29,712	66,611
Financial derivative instruments		170,121	81,277
Regulatory liability – fuel and purchased power costs refundable		74,085	—
Capital lease obligations		2,834,416	2,970,126
Asset retirement obligation		73,675	73,680
Deferred credits		133,024	203,637
Claims and damages		21,648	20,207
Total noncurrent liabilities		9,810,222	9,925,007
Net assets (deficit):			
Invested in capital assets net of related debt		(87,016)	(171,412)
Restricted		365	46,340
Unrestricted		463,820	444,792
Total net assets		377,169	319,720
Total liabilities and net assets	$	11,593,907	11,577,967

LONG ISLAND POWER AUTHORITY
(A Component Unit of the State of New York)

Statements of Revenues, Expenses, and Changes in Net Assets

Years ended December 31, 2010 and 2009

(Dollars in thousands)

		2010	2009
Operating revenues – electric sales	$	3,859,549	3,312,160
Operating expenses:			
Operations – fuel and purchased power		1,879,839	1,566,005
Operations and maintenance		1,129,931	864,576
General and administrative		41,852	40,153
Depreciation and amortization		251,117	254,944
Payments in lieu of taxes		281,609	249,652
Total operating expenses		3,584,348	2,975,330
Operating income		275,201	336,830
Nonoperating revenues and expenses:			
Other income, net:			
Investing income		6,237	5,029
Grant income		66,294	—
Carrying charges on regulatory asset		31,576	31,860
Other		8,632	(3,370)
Total other income, net		112,739	33,519
Interest charges and (credits):			
Interest on long-term debt, net		323,308	328,028
Other interest		14,116	12,333
Allowance for borrowed funds used during construction		(6,933)	(8,462)
Total interest charges		330,491	331,899
Total nonoperating revenues and expenses		(217,752)	(298,380)
Change in net assets		57,449	38,450
Total net assets, beginning of year		319,720	289,178
Cumulative effect of a change in accounting principle (note 4)		—	(7,908)
Total net assets, end of year	$	377,169	319,720

See accompanying notes to basic financial statements.

LONG ISLAND POWER AUTHORITY
(A Component Unit of the State of New York)

Statements of Cash Flows

Years ended December 31, 2010 and 2009

(Dollars in thousands)

		2010	2009
Cash flows from operating activities:			
Received from customers for system sales, net of refunds	$	3,738,230	3,528,777
Other operating revenues received		55,136	89,742
Paid to suppliers and employees:			
Operations and maintenance		(1,113,622)	(982,774)
Fuel and purchased power		(1,841,547)	(1,604,744)
Payments in lieu of taxes		(389,049)	(351,769)
Collateral on fuel derivative transactions, net		45,975	182,945
Net cash provided by operating activities		495,123	862,177
Cash flows from investing activities:			
Sales of investment securities		344,204	34,620
Purchase of investment securities		(335,275)	(126,234)
Fair value adjustment – short term securities		(15)	93
Realized gains on short term securities		(338)	(201)
Earnings received on investments		1,134	2,783
Other		1,925	(2,453)
Net cash provided by (used in) investing activities		11,635	(91,392)
Cash flows from noncapital financing related activities:			
Grant proceeds		50,691	—
Net cash provided by noncapital related activities		50,691	—
Cash flows from capital and related financing activities:			
Capital and nuclear fuel expenditures		(248,912)	(282,578)
Proceeds from promissory note		8,075	8,075
Proceeds from the issuance of bonds, net of discount/premium		421,759	445,045
Bond issuance costs		(2,379)	(3,112)
Interest paid, net		(306,977)	(319,639)
Redemption of long-term debt		(436,960)	(472,470)
Net cash used in capital and related financing activities		(565,394)	(624,679)
Net (decrease) increase in cash and cash equivalents		(7,945)	146,106
Cash and cash equivalents at beginning of year		371,264	225,158
Cash and cash equivalents at end of year	$	363,319	371,264
Reconciliation to net cash provided by operating activities:			
Operating income	$	275,201	336,830
Adjustments to reconcile operating income to net cash provided by operating activities:			
Depreciation and amortization		251,117	254,944
Nuclear fuel burned		7,466	6,690
Shoreham surcharges		40,987	35,923
Provision for claims and damages		218,805	50,683
Accretion of asset retirement obligation		4,236	2,729
Amortization of settlement benefits to ratepayers		(48,000)	(100,000)
Other, net		(5,518)	(1,730)
Changes in operating assets and liabilities:			
Accounts receivable, net		(271,204)	(12,334)
Regulatory asset – New York State assessment		9,252	(37,040)
Fuel and material and supplies inventory		(10,757)	(25,737)
Deferred fuel and purchased power costs		129,385	197,021
Counterparty collateral		45,975	182,945
Claims, damages and storm restoration		(180,921)	(39,847)
Accounts payable, accrued expenses and other		29,099	11,100
Net cash provided by operating activities	$	495,123	862,177

See accompanying notes to basic financial statements.

(1) Basis of Presentation

The Long Island Power Authority (Authority) was established as a corporate municipal instrumentality of the State of New York (State), constituting a political subdivision of the State, created by Chapter 517 of the Laws of 1986 (the LIPA Act). As such, it is a component unit of the State and is included in the State's annual financial statements.

The Authority's reporting entity is comprised of itself and its operating subsidiary the Long Island Lighting Company (LILCO), a wholly owned subsidiary of the Authority doing business as LIPA. LIPA has one share of $1 par value common stock authorized, issued and outstanding, which is held by the Authority.

As the Authority holds 100% of the common stock of LIPA and controls the operations of LIPA, under Governmental Accounting Standard Board Statement No. 14, *The Financial Reporting Entity*, LIPA is considered a blended component unit of the Authority and the assets, liabilities and results of operations are consolidated with the operation of the Authority for financial reporting purposes.

The Authority and its blended component unit, LIPA, are referred to collectively, as the "Authority" in the financial statements. All significant transactions between the Authority and LIPA have been eliminated.

(2) Nature of Operations

The Authority, as owner of the transmission and distribution system located in the New York State Counties of Nassau and Suffolk (with certain limited exceptions) and a small portion of Queens County known as the Rockaways (Service Area), is responsible for supplying electricity to customers within the Service Area. To assist the Authority in meeting these responsibilities, the Authority contracted with KeySpan Energy Corporation (KeySpan), a wholly owned subsidiary of National Grid plc, to provide: operations and management services related to the transmission and distribution system through a Management Services Agreement (MSA); capacity and energy from the fossil fired generating plants of KeySpan, through a Power Supply Agreement (PSA); and, fuel management services through an Energy Management Agreement (EMA) (collectively; the Operating Agreements). Through these contracts, the Authority pays KeySpan directly for these services and KeySpan, in turn, pays the salaries of its employees and fees of its contractors and suppliers. In 2010 and 2009, the Authority paid to KeySpan approximately $2 billion each year under the operating agreements, which includes all fees under such agreements, reimbursement for various taxes and PILOTS, certain fuel and purchased power costs, capital projects, conservation services, research and development and various other expenditures authorized by the Authority. In 2006, the Authority entered into agreements with certain of the KeySpan subsidiary companies to amend the MSA and certain other Operating Agreements. The Amended and Restated MSA has a term that expires on December 31, 2013.

Certain services provided for under the EMA expired on December 31, 2009. Through a competitive procurement process, the Authority has selected two new providers of those services. Both contracts commenced on January 1, 2010 for an initial five-year period and are subject to an extension for a period of five years at the Authority's option. Both contracts have been approved by the New York State Comptroller and the Attorney General.

The Authority has a right of first refusal to purchase, on substantially the same terms as offered, all (but not less than all) GENCO generating facilities which GENCO may decide to sell to a foreign or foreign-controlled entity during the term of the PSA (Right of First Refusal).

In consideration for the Authority's waiver of its rights under the change of control provisions in the Operating Agreements as a result of the National Grid acquisition of KeySpan in 2007, the Authority and National Grid reached an agreement (the Agreement and Waiver). Under the Agreement and Waiver, National Grid agreed to pay the Authority approximately $91 million over a period of seven years representing the Authority's guaranteed share of the synergy savings resulting from the National Grid acquisition of KeySpan. The Authority recorded the net present value (using a 7.8% interest rate) totaling approximately $68 million. As of December 31, 2010, the Authority has a current receivable of approximately $47 million and a noncurrent other receivable of approximately $25 million outstanding.

The Authority and LIPA are also parties to an Administrative Services Agreement, which describes the terms and conditions under which the Authority provides personnel, personnel-related services, and other services necessary for LIPA to provide service to its customers. As compensation to the Authority for the services described above, the Authority charges LIPA a monthly management fee equal to the costs incurred by the Authority in order to perform its obligations under the Administrative Services Agreement.

(3) Summary of Significant Accounting Policies

(a) General

The Authority complies with all applicable pronouncements of the Governmental Accounting Standards Board (GASB). In accordance with GASB Statement No. 20, *Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities That Use Proprietary Fund Accounting*, the Authority complies with all authoritative pronouncements applicable to nongovernmental entities (i.e., pronouncements of the Financial Accounting Standards Board) that do not conflict with GASB pronouncements.

The operations of the Authority are presented as an enterprise fund following the accrual basis of accounting in order to recognize the flow of economic resources. Under this basis, revenues are recognized in the period in which they are earned and expenses are recognized in the period in which they are incurred.

(b) Accounting for the Effects of Rate Regulation

The Authority is subject to the provisions of FASB ASC 980 *Regulated Operations* (previously SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*). This statement recognizes the economic ability of regulators, through the ratemaking process, to create future economic benefits and obligations affecting rate-regulated companies. Accordingly, the Authority records these future economic benefits and obligations as regulatory assets and regulatory liabilities, respectively.

Regulatory assets represent probable future revenues associated with previously incurred costs that are expected to be recovered from customers. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be refunded to customers through the ratemaking process.

In order for a rate-regulated entity to continue to apply the provisions of FASB ASC 980 *Regulated Operations*, it must continue to meet the following three criteria: (i) the enterprise's rates for regulated services provided to its customers must be established by an independent third-party regulator or its own governing board empowered by a statute to establish rates that bind customers; (ii) the regulated rates must be designed to recover the specific enterprise's costs of providing the regulated services; and (iii) in view of the demand for the regulated services and the level of competition, it is reasonable to assume that rates set at levels that will recover the enterprise's costs can be charged to and collected from customers.

Based upon the Authority's evaluation of the three criteria discussed above in relation to its operations, and the effect of competition on its ability to recover its costs, the Authority believes that FASB ASC 980 *Regulated Operations* continues to apply.

The Authority regularly assesses whether regulatory assets and liabilities are probable of recovery or refund. If recovery or refund is not approved by the Board of Trustees, which sets rates charged to customers, or if it becomes no longer probable that these amounts will be realized or refunded they would need to be written-off and recognized in the current period results of operations. In addition the acquisition adjustment totaling approximately $2.5 billion would be evaluated for impairment.

(c) Cash and Cash Equivalents and Investments

Funds held by the Authority are administered in accordance with the Authority's investment guidelines pursuant to Section 2925 of the New York State Public Authorities Law. These guidelines comply with the New York State Comptroller's investment guidelines for public authorities. Certain investments and cash and cash equivalents have been designated by the Authority's Board of Trustees to be used for specific purposes, including rate stabilization, debt service, and capital expenditures. Investments' carrying values are reported at fair market value. For a further discussion, see note 8.

(d) Counterparty Collateral

The Authority and its counterparties require collateral posting for mark-to-market valuations that exceed established credit limits. At December 31, 2010 and 2009, the Authority was required to post approximately $365,000 and $46 million, respectively, of collateral to various counterparties, which is considered a restricted net asset.

(e) Utility Plant and Property and Equipment

Additions to and replacements of utility plant are capitalized at original cost, which includes material, labor, indirect costs associated with an addition or replacement, plus an allowance for borrowed funds used during construction. The cost of renewals and betterments relating to units of property is added to utility plant. The cost of property replaced, retired or otherwise disposed of is deducted from utility plant and, generally, together with dismantling costs less any salvage, is charged to accumulated depreciation. The cost of repairs and minor renewals is charged to maintenance expense. Mass properties (such as poles, wire and meters) are accounted for on an average unit cost basis by year of installation. For a further discussion, see note 6.

Property and equipment represents leasehold improvements, office equipment and furniture and fixtures of the Authority.

(f) Fuel Inventory

Under the terms of the EMA and various Power Purchase Agreements, the Authority owns the fuel oil used in the generation of electricity at the facilities under contract to the Authority. Fuel inventory represents the value of low sulfur and other liquid fuels that the Authority had on hand at each year-end in order to meet the demand requirements of these generating stations. Fuel inventory is valued using the weighted average cost method.

(g) Material and Supplies Inventory

This represents the Authority's share of material and supplies inventory needed to support the operation of the Nine Mile Point 2 (NMP2) nuclear power station.

(h) Promissory Note Receivable

As part of the 1998 Merger, KeySpan issued promissory notes to the Authority of approximately $1.048 billion. As of December 31, 2010 and 2009, approximately $155 million remained outstanding. The fair market value of the note at December 31, 2010 and 2009 is approximately $156 million. The interest rates and timing of principal and interest payments on the promissory notes from KeySpan are identical to the terms of certain LILCO indebtedness assumed by the Authority in the merger. KeySpan is required to make principal and interest payments to the Authority thirty days prior to the corresponding payment due dates.

(i) Nonutility Property and Other Investments

The Authority's nonutility property and other investments consist primarily of the Nine Mile Point 2 Decommissioning Trust Funds (the Trusts). At December 31, 2010 and 2009, the value of the Trusts was approximately $81 million and $75 million, respectively.

(j) Other Long-Term Receivables

This represents the net present value of synergy savings credits due from National Grid resulting from their purchase of KeySpan as discussed in note 2. The Authority also recorded the net present value of a receivable related to the partial reimbursement of costs to construct the interconnection facilities related to the Neptune cable, which is to be paid to the Authority over a period of 20 years.

(k) Deferred Outflows

This represents the accumulated changes in the fair value of a derivative instrument that qualifies for hedge accounting as it is deemed effective. Under hedge accounting, the change in the fair value of a hedging derivative instrument is reported as a deferred inflow or deferred outflow on the Balance Sheets.

The change in fair value of ineffective hedges and other investment derivative instruments are reported as deferred charges, as the Authority is subject to the provisions of FASB ASC 980

(Continued)

Regulated Operations, and all such gains and losses are deferred until realized, which corresponds to the period they are recovered in rates.

(l) Deferred Charges

Deferred charges consists of primarily of (i) the balance of the ineffective investment derivative instruments; (ii) the unamortized balance of costs incurred to issue long-term debt which are amortized to interest expense over the life of the debt issuance to which they relate; and (iii) costs related to the transition to two new service providers who, after competitive solicitation were selected to provide support services to LIPA's fuel hedging program which commenced on January 1, 2010.

(m) Regulatory Assets

Shoreham Property Tax Settlement (Settlement)

In January 2000, the Authority reached an agreement with Suffolk County, Town of Brookhaven, Shoreham-Wading River Central School District, Wading River Fire District and Shoreham-Wading River Library District (which was succeeded by the North Shore Library District) (collectively, the Suffolk Taxing Jurisdictions) and Nassau County regarding the over assessment of the Shoreham Nuclear Power Station. As required under the terms of the agreement, the Authority was required to issue $457.5 million of rebates and credits to customers over the five-year period which began May 29, 1998. In order to fund such rebates and credits, the Authority used the proceeds from the issuance in May 1998 of its Capital Appreciation Bonds, Series 1998A Electric System General Revenue Bonds totaling approximately $146 million and the issuance in May 2000 of approximately $325 million of Electric System General Revenue Bonds, Series 2000A.

As provided under the Settlement, beginning in June 2003, Suffolk County customers' bills include a surcharge (the Suffolk Surcharge) to be collected over the succeeding approximate 25 year period to repay the debt service and issuance costs on the bonds issued by the Authority to fund the Settlement as well as its cost of pre-funding certain rebates and credits.

As future rates will be established at a level sufficient to recover all such costs identified above, the Authority recorded a regulatory asset in accordance with FASB ASC 980 *Regulated Operations*. The balance of the Shoreham property tax settlement regulatory asset as of December 31, 2010 and 2009 was approximately $543 million and $553 million, respectively. The balance represents rebates and credits issued to customers, costs of administering the program plus annual debt service costs on the bonds identified above less surcharges collected since 2003.

Southampton Visual Benefit Assessment

The Authority has recorded the incremental costs (approximately $12 million) incurred to bury a portion of a transmission cable routed through the Town of Southampton (Town) that will be recovered from certain customers of the Town over a period of 20 years beginning in 2009.

New York State Temporary Energy and Utility Conservation Assessment

As a result an amendment to the Public Service Law effective April 1, 2009, utilities in the State are required to collect from all customers a special assessment which will be paid directly to the State for a five year period that began in 2009. As the Authority's rates did not include the recovery of this assessment until approved by the Board of Trustees effective January 1, 2010, the 2009 assessment has been deferred and will be collected ratably from customers over the next four years.

Fuel and Purchased Power Costs Recoverable

The Authority's tariff includes a fuel recovery provision – the Fuel and Purchased Power Cost Adjustment (FPPCA) that provides for the recovery of fuel and purchased power costs in the period incurred, up to amounts sufficient to allow the Authority to earn a financial target of $75 million with a variance of $50 million above or below such amount in each year. Should fuel and purchased power prices change such that Authority would exceed or fail to meet its financial target, the FPPCA would be reduced or increased accordingly. In no event, however, may Authority recover an amount that exceeds its fuel and purchased power costs incurred.

Prior to 2004, the Authority deferred a portion of its excess fuel and purchased power costs and collected those costs in subsequent years. In order to transition to a current period recovery method, the Authority deferred, in 2003, approximately $365 million of unrecovered fuel and purchased power costs to be recovered over a 10-year period beginning January 1, 2004. As of December 31, 2010 and 2009, the uncollected balance of this deferral totaled approximately $110 million and $148 million, respectively.

Also recorded as fuel and purchased power costs recoverable are amounts incurred related to various energy projects, whose amortization is charged to fuel and purchased power costs over the period of benefit (the life of the power purchase agreement.) As of December 31, 2010 and 2009, the uncollected balance of this deferral totaled approximately $38 million and $39 million, respectively.

(n) Acquisition Adjustment

The acquisition adjustment, an intangible asset, represents the difference between the purchase price paid and the net assets acquired from LILCO and is being amortized and recovered through rates on a straight-line basis using a 35-year life. The net unamortized value of the acquisition adjustment decreased approximately $30 million to reflect the true up resulting from the unbilled revenue change discussed in Revenues.

(o) Capitalized Lease Obligations

Capitalized lease obligations represent the net present value of various contracts for the capacity and/or energy of certain generation and transmission facilities in accordance with FASB ASC 840 Leases (previously Emerging Issues Task Force No. 01-08, *Determining Whether an Arrangement Contains a Lease* and previously SFAS No. 13, *Accounting for Leases*). Upon satisfying the capitalization criteria, the net present value of the contract payments is included in both Utility Plant and Capital Lease Obligations.

The Authority recognizes in fuel and purchased power expense an amount equal to the contract payment of the capitalized leases discussed above, as allowed through the ratemaking process. The value of the asset and the obligation is reduced each month so that the balance sheet properly reflects the remaining value of the asset and obligation at each month end.

For a further discussion on the capitalization of capacity and/or energy contracts, see note 12.

(p) Deferred Credits

Deferred credits primarily represent amounts received from KeySpan/National Grid (Grid benefits) as a result of certain renegotiated agreements. The Board authorized $48 million and $100 million of these Grid benefits to be used during 2010 and 2009, respectively, as a reduction to the amounts recoverable from customers through the FPPCA, and in 2009 provided for the establishment of a $10 million fund to assist qualifying low income senior citizens customers which expired in August 2010 with an used balance of approximately $6 million.

(q) Borrowings

Borrowings represent the unamortized balance of cash premiums received at the time of entering into certain financial derivative instruments. The Authority is amortizing such premiums over the life of the instrument in accordance with GASB No. 53.

(r) Commodity and Financial Derivative Instruments

Represents the amount that the Authority believes it would be required to pay in order to terminate these derivative instruments as of December 31, 2010 and 2009 which approximates fair value.

(s) Claims and Damages

Losses arising from claims including workers' compensation claims, property damage, and general liability claims are partially self-insured. Storm losses are self-insured. Reserves for these claims and damages are based on, among other things, experience, and expected loss.

(t) Revenues

Operating revenues are comprised of cycle billings for electric service rendered to customers, based on meter reads, and the accrual of revenues for electric service rendered to customers not billed at month-end. Effective January 1, 2010, the Authority changed its methodology for the accrual of revenues. After an extensive analysis of the prior methodology which based the estimate of unbilled sales on several factors including electrical usage, seasonal factors, rate differentials and line losses, the Authority has determined that a more accurate and appropriate method is to accrue unbilled revenues by estimating unbilled consumption at the customer meter.

Application of the new methodology to the prior years resulted in an increase of net assets of approximately $72 million, $62 million from increased sales and approximately $10 million due to reduced amortization related to a reserve acquired from LILCO in 1998.

All other revenue is reported as nonoperating revenue when service is rendered. Fuel and purchased power supply costs recoveries collected in excess of that incurred are deferred until the FPPCA rate is adjusted. For the years ended December 31, 2010 and 2009, the Authority received approximately 53% of its revenues from residential sales, 43% from sales to commercial and industrial customers, and the balance from sales to public authorities and municipalities.

(u) Depreciation and Amortization

The provisions for depreciation for utility plant result from the application of straight-line rates by groups of depreciable properties in service. The rates are determined by age-life studies performed on depreciable properties. The average composite depreciation rate is 2.85% and 2.85% for December 31, 2010 and 2009, respectively.

Leasehold improvements are being amortized over the lesser of the life of the assets or the term of the lease, using the straight-line method. Property and equipment is being depreciated over its estimated useful life using the straight-line method.

The following estimated useful lives and capitalization thresholds are used for utility property:

Category	Useful life	Capitalization threshold
Generation – nuclear	39 – 46 years	$ 200
Transmission and distribution	20 – 48 years	200
Common	4 – 41 years	200
Nuclear fuel in process and in reactor	6 years	—
Generation assets under capital lease	10 – 25 years	—

(v) Payments-in-Lieu-of-Taxes

The Authority makes payments-in-lieu-of-taxes (PILOTS) for all operating taxes previously paid by LILCO, including gross income, gross earnings, property, Metropolitan Transportation Authority and certain taxes related to fuels used in utility operations. In addition, the Authority has entered into various PILOT arrangements for property it owns, upon which merchant generation and transmission is built.

(w) Allowance for Borrowed Funds Used during Construction

The allowance for borrowed funds used during construction (AFUDC) is the net cost of borrowed funds used for construction purposes. AFUDC is not an item of current cash income. AFUDC is computed monthly on a portion of construction work in progress, and is shown as a net reduction in interest expense. The AFUDC rates were 5.09% and 5.19% for the years ended December 31, 2010 and 2009, respectively.

(x) Income Taxes

The Authority is a political subdivision of the State of New York and, therefore, is exempt from Federal, state, and local income taxes.

(y) Regulatory Liability – Fuel and Purchased Power Costs Refundable

Regulatory liabilities represent amounts that are expected to be refunded to customers through the ratemaking process. In accordance with the FPPCA, the Authority must return any FPPCA revenues it recovers in excess of the fuel and purchased power costs it incurs. Any such over recoveries are recognized as regulatory liabilities.

A regulatory liability for approximately $129 million was recorded in 2010. This amount resulted from the change in the unbilled revenue estimate and represents deferred revenue that will be refunded to customers. The Authority will return this excess to customers over a three year period $55 million in 2011 and $37 million in 2012 and 2013.

(z) Asset Retirement Obligation

The Authority follows FASB ASC 410 *Asset Retirement and Environment Obligations* (previously SFAS No. 143, *Accounting for Asset Retirement Obligations*). An Asset Retirement Obligation (ARO) exists when there is a legal obligation associated with the retirement of a tangible long-lived asset that results from the acquisition, construction, or development and/or normal operation of the asset. The Authority, as an 18% owner of Nine Mile Point 2 (NMP2) Nuclear Power Station, has a legal obligation associated with its retirement. This obligation is offset by the capitalization of the asset which is included in "Utility plant and property and equipment". As of December 31, 2010 and 2009, the NMP2 asset retirement obligation totaled approximately $67 million and $68 million, respectively. The Authority maintains a Trust for the decommissioning of NMP2. The decommissioning funds are reported at their fair market value and any unrealized gains or losses are deferred as a component of the ARO in accordance with FASB ASC 980 *Regulated Operations* and have no impact to the Authority's net assets. For a further discuss on the Authority's NMP2 decommissioning obligations and related funding see note 7.

Additionally, FASB ASC 410 *Asset Retirement and Environment Obligations* defines the term conditional asset retirement obligation as a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. As of December 31, 2010 and 2009, the asset retirement obligation for the Authority's utility assets totaled approximately $7 million and $6 million, respectively.

A summary of the asset retirement obligation activity of the Authority for the years ended December 31, 2010 and 2009 is included below (amount in thousands):

		2010	2009
Asset retirement obligation:			
Beginning balance	$	73,680	92,558
Changes in fair market value of decommissioning fund		729	977
Change in estimate		(5,063)	(22,584)
Accretion expense		4,329	2,729
Balance at December 31,	$	73,675	73,680

(aa) Long-Lived Assets

Long-lived assets and purchased intangibles subject to amortization, are reviewed for impairment whenever events or changes in circumstances indicate that there is a significant unexpected decline in the service utility of a capital asset. Impairment is measured using one of three approaches that best reflects the decline in service utility. Assets to be disposed of and assets held for sale are reported at the lower of the carrying amount or fair value less costs to sell.

(bb) Use of Estimates

The accompanying financial statements were prepared in conformity with U.S. generally accepted accounting principles which require management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

(cc) Reclassifications

Certain prior year amounts have been reclassified in the financial statements to conform to the current year presentation. In prior years, approximately $11 million was recorded as a direct reduction to accounts receivable for specific accounts which had been determined to be potentially uncollectible. This amount has been reclassified to the allowance for doubtful accounts. The net effect has no impact on net accounts receivable as it is a reclassification within accounts receivable. This also has no impact on change in net assets.

(dd) Recent Accounting Pronouncements

In June 2008, GASB issued Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments* (GASB 53). This statement requires that the fair value of financial arrangements called “derivatives” or “derivative instruments” be reported in the financial statements of state and local governments. If a derivative effectively hedges (significantly reduces) an identified risk of rising or falling cash flows or fair values, then its annual fair value changes are deferred until the hedged transaction occurs or the derivative ceases to be effective. Alternatively, the annual change in the fair value of other derivatives should be reported immediately as investment income or loss, which the

Authority then defers in accordance with its tariff as provided under FASB 71. Additional information about derivatives should be disclosed in the notes to the financial statements, including identification of the risks to which hedging derivative instruments expose the Authority. GASB No. 53 became effective for the Authority beginning in 2010. For a further discussion, see note 4.

In March 2009, GASB issued Statement No. 55, *The Hierarchy of Generally Accepted Accounting Principles for State and Local Governments* (GASB No. 55). GASB No. 55 incorporates the hierarchy of GAAP for state and local governments into GASB's authoritative literature. Prior to this standard, the GAAP hierarchy was included in an American Institute of Certified Public Accountants (AICPA) Statements on Auditing Standards, rather than in the GASB's literature. This statement was effective for the Authority upon issuance and does not have a material impact on the Authority's financial statements.

In March 2009, GASB issued Statement No. 56, *Codification of Accounting and Financial Reporting Guidance contained in the AICPA Statements on Auditing Standards* (GASB No. 56). GASB No. 56 incorporates certain accounting and financial reporting guidance presented in the AICPA'S Statements on Auditing Standards into the GASB's authoritative literature. This statement was effective for the Authority upon issuance and does not have a material impact on its financial statements.

In December 2009, GASB issued Statement No. 57, *OPEB Measurements by Agent Employers and Agent Multiple – Employer Plans* (GASB No. 57). GASB No. 57 addresses issues related to the use of alternative measurement method and the frequency and timing of measurements by employers that participate in agent multiple-employer OPEB plans. The statement amends previous GASB statements on OPEB plans, and will improve the consistency of reporting for OPEB plans. This statement is effective for the Authority beginning in 2012. The Authority does not believe this statement will have a material impact on its financial statements.

In June 2010, GASB issued Statement No. 59, *Financial Instruments Omnibus* (GASB No. 59). GASB No. 59 addresses topics relating to the reporting and disclosure of certain financial instruments and external investment pools, and includes some clarifications to GASB No. 53. This statement becomes effective in 2011. The Authority does not believe this statement will have a material impact on its financial statements.

In December 2010, GASB issued Statement No. 62, *Codification of Accounting and Financial Reporting Guidance Contained in the Pre-November 30, 1989 FASB and AICPA Pronouncements* (GASB No. 62). GASB No. 62 incorporates into GASB's authoritative literature certain accounting and financial reporting guidance issued on or before November 30, 1989 included in: FASB Statements and Interpretations, Accounting Principles Board Opinions, and Accounting Research Bulletins of the AICPA Committee on Accounting Procedure that do not conflict with or contradict GASB pronouncements. The statement also supersedes Statement No. 20*, Accounting and Financial Reporting for Proprietary Fund Accounting* which eliminates the election for business-type activities to apply post November 30, 1989 FASB Statements and Interpretations that do not conflict with GASB pronouncements. This statement becomes effective 2012. The Authority does not believe this statement will have a material impact on its financial statements.

(4) Derivative Instruments

In 2010, the Authority implemented GASB No. 53 which requires retroactive application by restating all prior periods presented in the financial statements. The Authority has restated its 2009 financial statements to comply with GASB No. 53 with an approximate $8 million adjustment to its 2009 beginning net assets. The adjustment was primarily due to the change in the method of amortizing the upfront premiums received on certain of the Authority's swaps which are now considered borrowings. For 2010, the Authority recognized approximately $7 million of incremental interest charges as a result of amortizing the upfront premiums as required by GASB No. 53.

The Authority uses derivative instruments to attempt to manage the cash flow impact of interest rate changes and market price fluctuations for the purchase of fuel oil, natural gas and electricity on its customers, net assets and cash flows. The Authority also utilizes financial derivative instruments to attempt to mitigate its exposure to certain market risks associated with operations and does not use derivative financial instruments for trading or speculative purposes. These contracts are evaluated pursuant to GASB No. 53 to determine whether they meet the definition of derivative instruments, and if so, whether they effectively hedge the expected cash flows associated with interest rate and commodity price risk exposures. The fair values of the Authority's derivatives as defined by GASB No. 53 are reported on the Balance Sheets as Derivative Instruments.

The Authority applies hedge accounting for derivative instruments that are deemed effective hedges and under GASB No. 53 are referred to as hedging derivative instruments. Under hedge accounting, changes in the fair value of a hedging derivative instrument is reported as a deferred inflow or deferred outflow on the Balance Sheets until the contract is settled or hedge accounting is terminated.

The Authority's derivative instruments that do not meet the definition of a hedging derivative instrument are referred to as investment derivative instruments. Changes in the fair value of investment derivative instruments are deferred until settled or terminated.

All settlement payments or receipts for hedging derivative instruments are recorded as either fuel and purchased power expense or interest expense for interest rate derivatives on the Statements of Revenues, Expenses and Changes in Net Assets in the period settled. All settlement payments or receipts related to investment derivative instruments are recorded as interest expense or as fuel and purchased power expense in the Statements of Revenues, Expenses and Changes in Net Assets in the period incurred.

A portion of the Authority's fuel and purchased power derivative contracts are exchange-traded contracts with readily available quoted market prices. Another portion is non exchange-traded contracts valued using prices provided by external sources, primarily price quotations available through brokers or over-the-counter, on-line exchanges. The remainder of the fuel and purchased power as well as the financial derivative products represents contracts for which external sources or observable market quotes are not available. These contracts are valued based on various valuation techniques including but not limited to models internal to the Authority's energy risk management consultant based on extrapolation of observable market data with similar characteristics. Contracts valued with prices provided by models and other valuation techniques make up a significant portion of the total fair value of such derivative contracts. The Authority's policy is to not discount the fair value of each contract using an interest rate which represents default risk associated with a particular counterparty.

The Authority's derivative instruments at December 31, 2010 are as follows (in thousands):

Derivative instrument description		Fair value December 31, 2010	Net change in fair value	Fair value December 31, 2009	Type of hedge	Financial statement classification for changes in fair value
Hedging derivative instruments:						
Financial derivatives:						
Interest Rate Swap 1	$	(27,969)	(11,904)	(16,065)	Cash flow	Deferred outflow
Interest Rate Swap 2		(17,498)	(6,788)	(10,710)	Cash flow	Deferred outflow
Interest Rate Swap 3	$	(81,957)	(27,924)	(54,033)	Cash flow	Deferred outflow
Interest Rate Swap 7		(6,430)	(92)	(6,338)	Cash flow	Deferred outflow
Total	$	(133,854)	(46,708)	(87,146)		
Commodity derivatives:						
Natural Gas Swaps	$	(93,906)	2,550	(96,456)	Cash flow	Deferred outflow
Residual Oil Swaps		(11,648)	(41,744)	30,096	Cash flow	Deferred outflow
Purchased Power Swaps		(10,933)	52,029	(62,962)	Cash flow	Deferred outflow
Natural Gas Basis Swaps		3,523	7,297	(3,774)	Cash flow	Deferred outflow
Residual Oil Options		(535)	12,075	(12,610)	Cash flow	Deferred outflow
Natural Gas Options		(940)	29,693	(30,633)	Cash flow	Deferred outflow
Total	$	(114,439)	61,900	(176,339)		
Investment derivative instruments:						
Financial derivatives:						
Interest Rate Swap 4		(18,133)	(21,066)	2,933	N/A	Deferred charges
Interest Rate Swap 5		(9,067)	(10,535)	1,468	N/A	Deferred charges
Interest Rate Swap 6		(9,067)	(10,535)	1,468	N/A	Deferred charges
Total	$	(36,267)	(42,136)	5,869		
Commodity derivatives:						
Natural Gas Options	$	(19)	2,353	(2,372)	N/A	Deferred charges
Natural Gas Swaps		(8,340)	(7,512)	(828)	N/A	Deferred charges
Total	$	(8,359)	(5,159)	(3,200)		

The terms of the Authority's commodity derivative instruments that were outstanding at December 31, 2010 and 2009 are summarized in the tables below:

	Notional amount ('000s)	Beginning date	Ending date	Authority pays per unit	Authority receives
2010:					
Natural Gas Swaps	62,168 Dths	1/1/2011	12/31/2013	$ 5.06 to 11.06	Natural Gas at Henry Hub
Residual Oil Swaps	1,772 Bbls	1/1/2011	7/31/2013	63.5 to 122.8	Residual Fuel Oil at New York Harbor
Purchased Power Swaps	1,906 Mwhs	1/1/2011	9/30/2013	60.5 to 144	Power at PJM East
Natural Gas Basis Swaps	3,393 Dths	1/1/2011	3/1/2011	0.57 to 3.25	Gas Basis between Henry Hub and Transco Z6, New York
Residual Oil Options	30 Bbls	1/1/2011	2/28/2011	94.35 to 100.35	Residual Fuel Oil at New York Harbor
Natural Gas Options	768 Dths	1/1/2011	10/31/2012	5.85 to 9.5	Natural Gas at Henry Hub

	Notional amount (000's)	Beginning date	Ending date	Authority pays per unit	Authority receives
2009:					
Natural Gas Swaps	56,143 Dths	1/1/2010	12/31/2012	$ 5.3 to 11.73	Natural Gas at Henry Hub
Residual Oil Swaps	2,925 Bbls	1/1/2010	12/31/2012	52.2 to 122.8	Residual Fuel Oil at New York Harbor
Purchased Power Swaps	– Mwhs	1/1/2010	12/31/2010	47 to 147.5	Power at PJM East
Natural Gas Basis Swaps	5,323 Dths	1/1/2010	3/31/2010	1.33 to 5.85	Gas Basis between Henry Hub and Transco Z6, New York
Residual Oil Options	770Bbls	1/1/2010	2/28/2011	53.5 to 102.7	Residual Fuel Oil at New York Harbor
Natural Gas Options	13,345 Dths	1/1/2010	7/31/2011	6.65 to 12.5	Natural Gas at Henry Hub

(Continued)

The terms of the Authority's financial derivative instruments that were outstanding at December 31, 2010 are summarized in the tables below (amounts in thousands):

Financial derivative	Type	Effecitve date	Termination date	Authority pays	Authority receives		Orignal notional		Upfront cash payment
Interest rate:									
Swap 1	Synthetic Fixed	11/12/1998	4/1/2025	4.208%	SIFMA	$	150,000	$	—
Swap 2	Synthetic Fixed	11/12/1998	4/1/2025	4.208	SIFMA		100,000		—
Swap 3	Synthetic Fixed	6/1/2003	12/1/2029	5.120	69.47% of 1-month LIBOR		587,225		106,400
Swap 4	Basis Swap	7/1/2004	8/15/2033	SIFMA	70.50% of 1-month LIBOR		502,090		17,500
Swap 5	Basis Swap	7/1/2004	8/15/2033	SIFMA	70.50% of 1-month LIBOR		251,045		8,750
Swap 6	Basis Swap	7/1/2004	8/15/2033	SIFMA	70.50% of 1-month LIBOR		251,045		8,750
Swap 7	Synthetic Fixed	7/11/2006	9/1/2015	4.110%	CPI + 0.765%		110,715		—

In May 2010 the Authority undertook a current refunding of a portion of the VRDOs hedged by Interest Rate Swap 3 and the interest rate swap was reassigned to a new underlying notional with identical terms. This refunding and reassignment effectively terminated the original hedge. At December 31, 2009, Interest Rate Swap 3 was considered a hedging derivative instrument. In accordance with GASB No. 53, at the time of a termination event related to a current refunding of the hedged debt, the balance of the amounts in deferred outflows are to be included in the net carrying amount of the refunded debt for the purposes of calculating the deferred loss on refunding. As only a portion of the hedged debt was refunded the Authority prorated the deferral. The $82 million deferred outflow at the refunding date was apportioned to the deferred loss on refunding ($32 million) and to deferred charges ($56 million). The change in fair value of Swap 3 from the refunding date to December 31, 2010 is reported as a deferred outflow ($5.8 million) as the Swap was determined to be effective at December 31, 2010.

Collateral Posting: Under certain conditions, the Authority may be required to post collateral related to its interest rate derivative instruments. Under the terms of its interest rate derivative agreements, collateral may be required if the Authority's credit ratings and, in the case of insured swaps, the credit ratings of any related interest rate swap insurer, fall below minimum levels as provided in each swap agreement, and the Authority fails to provide alternative credit enhancements. Collateral for its financial derivatives, if required, would approximate fair value. The Authority has never been required to posted collateral under its interest rate derivative instruments.

The Authority has collateral requirements for all of its commodity derivatives. Collateral is required to be posted with the counterparty when the negative fair value of the commodity derivative instrument exceeds the unsecured line of credit established with each counterparty as listed in the counterparty table below. In the event of collateral being posted, the value will equal the difference between the fair value and the amount of the unsecured line of credit. At December 31, 2010 and 2009, the Authority had posted collateral with counterparties of approximately $0.4 million and $46.4 million, respectively.

The Authority is exposed to the following risks related to derivative instruments as defined by GASB No. 53:

Credit Risk: The risk that the counterparty (or its guarantor) will default on its obligations under the agreement. Currently, counterparty risk for the Authority is limited as the termination values of the transactions are generally negative. Additionally, the Authority has sought to limit counterparty risk by contracting only with highly rated counterparties or requiring guarantees of the counterparty's obligations. Below is a table with the credit-ratings of the Authority's counterparties:

Counterparty	Moody's	S&P	Authority's unsecured line of credit (millions)
Barclays Bank PLC	Aa3	AA-	$ 40
BP Corporation North America Inc.	Baa1	A	10
Credit Suisse Energy LLC	Aa1	A+	40
Deutsche Bank AG	Aa3	A+	50
J. Aron & Company	A1	A	40
JPMorgan Chase Bank, N.A.	Aa1	AA-	25
Macquarie Energy LLC	A1	A	10
Lehman Brothers Financial Products Inc.	Not rated	Not rated	—
Societe Generale	Aa2	A+	25
UBS AG, Stamford Branch	Aa3	A+	—
Bear Stearns Capital Markets Inc.	Aa3	A+	—
Citibank, N.A. New York	A1	A+	—
Merrill Lynch Commodities, Inc.	A2	A	20
Bank of America Corp	A2	A	—
Morgan Stanley Capital Group Inc.	A2	A	40

Termination Risk: Termination risk is the risk that a derivative could be terminated by a counterparty prior to its scheduled maturity due to a contractual event with the Authority owing a termination payment and no longer meeting the objective of the hedge. As long as the Authority fulfills its obligations under the contracts and does not default under the agreements, the counterparties do not have the right to terminate these agreements. The Authority believes that termination risk is low because the counterparties may terminate the agreements only upon the occurrence of specific events such as, payment defaults, other defaults which remain uncured for 30 days after notice, bankruptcy or insolvency of the Authority (or similar events), or a downgrade of the Authority's and its insurer's, if any, credit rating below investment grade. If, at the time of termination, the mark-to-market of the derivative was a liability of the Authority, the Authority could be required to pay that amount to the counterparty. Termination risk associated with all of the Authority's derivatives is limited to the fair value.

Basis Risk: The Authority is exposed to basis risk on certain of its pay-fixed interest rate swaps because the variable-rate payments received by the Authority (SIFMA, 69.47% of LIBOR) on these hedging derivative instruments are based upon indexes other than the actual interest rates the Authority pays on its hedged variable rate debt. The terms of the related hedging fixed rate swap transactions are summarized in the charts above.

The Authority is exposed to other basis risk on a portion of its commodity swaps when the commodity swap payment received is based upon a reference price in market (i.e. natural gas priced at Henry Hub) that differs from the market in which the hedged item is expected to be bought (natural gas priced at New York gate). If the correlation between these market prices should fail the Authority may incur costs as a result of the hedging derivative instrument's inability to offset the price of the related commodity.

Rollover risk: The Authority is exposed to rollover risk on its Swap 1 and 2. Certain of it Series 2001 2A, 3A and 3B bonds mature in 2030 while Swap 1 and 2 terminate in April 2025, leaving the Authority exposed to interest rate volatility during the period from 2025 to 2030.

(5) Rate Matters

Under current New York State law, the Board of Trustees of the Authority is empowered to set rates for electric service in the Service Area without the approval of the New York State Public Service Commission (PSC) or any other state regulatory body. However, in connection with the approval of the 1998 merger of the Authority and LILCO (d/b/a LIPA) by the New York State Public Authorities Control Board (the PACB), the Authority agreed that it would comply with the condition imposed by the PACB and not impose any permanent increase, nor extend or re-establish any portion of a temporary rate increase, in average customer rates over a 12-month period in excess of 2.5% without approval of the PSC, following a full evidentiary hearing. Another of the PACB conditions requires that the Authority reduce average base rates within the service area by no less than 14% over a ten-year period commencing on the date when the Authority began providing electric service, when measured against LILCO's base rates in effect on July 16, 1997 (excluding the impact of the Shoreham Property Tax Settlement, but adjusted to reflect emergency conditions and extraordinary unforeseeable events, including a precipitous rise in oil prices). The 10-year period expired May 28, 2008.

The LIPA Act requires that any bond resolution of the Authority contain a covenant that it will at all times maintain rates, fees or charges sufficient to pay the costs of: operation and maintenance of facilities owned or operated by the Authority; PILOTS; renewals, replacements and capital additions; the principal of and interest on any obligations issued pursuant to such resolution as the same become due and payable. In addition, the Authority must establish or maintain reserves or other funds or accounts required or established by or pursuant to the terms of such resolution.

In addition to the delivery rate, the Authority's tariff also includes: (i) the FPPCA, to allow for adjustments to customers' bills to reflect changes in the cost of fuel and purchased power and related costs; (ii) a PILOTS recovery rider, which allows for rate adjustments to accommodate PILOTS; (iii) a rider providing for the recovery of costs associated with the Shoreham Property Tax Settlement; (iv) a rider for the Authority's energy efficiency and renewables program; and (v) a rider providing for the collection of the Temporary State Assessment imposed by the New York State Legislature.

As part of its ratemaking jurisdiction, and due to rising costs, the Authority proposed for the first time, an increase to its delivery rates as part of the 2011 budget proposal. The Authority proposed an increase of approximately 1.9% across all rate classes to increase its recovery of operating expenses and property taxes (among other things) and achieve the targeted $75 million in net income. The Authority's Trustees approved the budget in December 2010 and, following public notice and hearings, approved the rate increase in February 2011, to be effective on March 1, 2011.

For a further discussion on rate matters, see note 13.

(6) Utility Plant and Property and Equipment

The following schedule summarizes the utility plant and property and equipment of the Authority as of December 31, 2010 (amounts in thousands):

	Beginning balance	Additions	Deletions	Ending balance
Capital assets, not being depreciated:				
Land	$ 16,693	873	—	17,566
Retirement work in progress	35,940	17,964	18,851	35,053
Construction in progress	189,098	252,378	273,064	168,412
Total capital assets not being depreciated	241,731	271,215	291,915	221,031
Capital assets, being depreciated:				
Generation – nuclear	708,078	9,136	12,904	704,310
Transmission and distribution	3,284,051	252,869	30,310	3,506,610
Common	37,194	2,806	198	39,802
Nuclear fuel in process and in reactor	93,791	2,984	450	96,325
Office equipment, furniture, and leasehold improvements	5,280	12,579	6,042	11,817
Generation and transmission assets under capital lease	3,555,024	—	—	3,555,024
Total capital assets being depreciated	7,683,418	280,374	49,904	7,913,888
Less accumulated depreciation for:				
Generation – nuclear	250,926	21,817	7,931	264,812
Transmission and distribution	674,156	122,565	39,575	757,146
Common	12,684	3,924	162	16,446
Nuclear fuel in process and in reactor	66,773	7,466	—	74,239
Office equipment, furniture, and leasehold improvements	3,947	1,535	—	5,482
Generation assets under capital lease	456,945	127,953	—	584,898
Total accumulated depreciation	1,465,431	285,260	47,668	1,703,023
Net value of capital assets, being depreciated	6,217,987	(4,886)	2,236	6,210,865
Net value of all capital assets	$ 6,459,718	266,329	294,151	6,431,896

In 2010, depreciation expense related to capital assets was approximately $150 million.

The following schedule summarizes the utility plant and property and equipment of the Authority as of December 31, 2009 (amounts in thousands):

		Beginning balance	Additions	Deletions	Ending balance
Capital assets, not being depreciated:					
Land	$	16,089	604	—	16,693
Retirement work in progress		34,159	19,480	17,699	35,940
Construction in progress		272,733	243,370	327,005	189,098
Total capital assets not being depreciated		322,981	263,454	344,704	241,731
Capital assets, being depreciated:					
Generation – nuclear		713,876	7,341	13,139	708,078
Transmission and distribution		3,047,676	307,161	70,786	3,284,051
Common		31,493	6,435	734	37,194
Nuclear fuel in process and in reactor		73,207	20,584	—	93,791
Office equipment, furniture, and leasehold improvements		4,607	673	—	5,280
Generation and transmission assets under capital lease		2,818,947	736,077	—	3,555,024
Total capital assets being depreciated		6,689,806	1,078,271	84,659	7,683,418
Less accumulated depreciation for:					
Generation – nuclear		233,524	21,862	4,460	250,926
Transmission and distribution		634,898	115,664	76,406	674,156
Common		8,767	4,392	475	12,684
Nuclear fuel in process and in reactor		60,083	6,690	—	66,773
Office equipment, furniture, and leasehold improvements		3,570	377	—	3,947
Generation assets under capital lease		346,935	110,010	—	456,945
Total accumulated depreciation		1,287,777	258,995	81,341	1,465,431
Net value of capital assets, being depreciated		5,402,029	819,276	3,318	6,217,987
Net value of all capital assets	$	5,725,010	1,082,730	348,022	6,459,718

In 2009, depreciation expense related to capital assets was approximately $142 million.

(7) Nine Mile Point Nuclear Power Station, Unit 2 (NMP2)

The Authority has an undivided 18% interest in Nine Mile Point 2 Nuclear Power Station (NMP2), located in Scriba, New York, operated by Constellation Energy Nuclear Group, LLC (Constellation) a division of Constellation Energy Group, Inc. (CEG).

The Authority's share of the rated capability of NMP2 is approximately 207 megawatts (MW). The net utility plant investment, excluding nuclear fuel, was approximately $444 million and $457 million as of December 31, 2010 and 2009, respectively. Generation from NMP2 and operating expenses incurred by NMP2 are shared by the Authority at its 18% ownership interest. The Authority is required to provide its share of financing for any capital additions to NMP2. Nuclear fuel costs associated with NMP2 are being amortized on the basis of the quantity of heat produced for the generation of electricity.

The Authority has an operating agreement for NMP2 with Constellation, which provides for a management committee comprised of one representative from each co-tenant. Constellation controls the operating and maintenance decisions of NMP2 in its role as operator. The Authority and Constellation have joint approval rights for the annual business plan, the annual budget and material changes to the budget. In addition to its involvement through the management committee, the Authority maintains on-site nuclear oversight representation to provide additional support to protect the Authority's interests.

The Nuclear Regulatory Commission (NRC) granted a license extension for the Nine Mile Point 2 facility extending the license through October 2046.

(a) Nuclear Plant Decommissioning

Provisions for decommissioning costs for NMP2 are based on the most current site-specific study prepared by Constellation in 2010. As a result of that study, the Authority's share of the total decommissioning costs for both the contaminated and noncontaminated portions is $67 million as of December 31, 2010 and is included in the balance sheet as a component of the asset retirement obligation. Reduction in the asset retirement obligation from the 2009 position was attributable primarily to the lengthening of the expected dormancy period prior to the commencement of decommissioning activities, partially offset by additional costs associated with the expected delay by the DOE in providing a permanent centralized repository for spent nuclear fuel and the reduction in the credit-adjusted risk-free interest rate. The Authority maintains a nuclear decommissioning trust fund (NDT) for its share of the decommissioning costs of NMP2, which as of December 31, 2010 and 2009 had an approximate value of $81 million and $75 million, respectively. Based on assumptions on deposits and investment returns being maintained within these funds, the Authority believes that the value of these trusts will be sufficient to meet the Authority's expected decommissioning obligations.

(b) NMP2 Radioactive Waste

Constellation has contracted with the U.S. Department of Energy (DOE) for disposal of high-level radioactive waste (spent fuel) from NMP2. Despite a court order reaffirming the DOE's obligation to accept spent nuclear fuel by January 31, 1998, the DOE has not forecasted the start of operations of

(Continued)

its high-level radioactive waste repository. The Authority has been advised by Constellation that the NMP2 spent fuel storage pool has a capacity for spent fuel that is adequate until 2012. A drywell fuel storage facility is being constructed for NMP2 spent fuel at the plant. The Authority reimburses Constellation for its 18% share of the disposal costs of spent fuel at a rate of $1.00 per megawatt hour of net generation, less a factor to account for transmission line losses. Such costs are included in the cost of fuel and purchased power.

(c) Nuclear Plant Insurance

Constellation procures public liability and property insurance for NMP2 and the Authority reimburses Constellation for its 18% share of those costs.

The Terrorism Risk Insurance Act (TRIA) of 2002 was signed into law in 2002, which was then extended by the Terrorism Risk Insurance Extension Act of 2005 and the Terrorism Risk Insurance Program Reauthorization Act of 2007. Under the TRIA, property and casualty insurance companies are required to offer insurance for losses resulting from certified acts of terrorism. Certified acts of terrorism are determined by the Secretary of the Treasury, in concurrence with the Secretary of State and Attorney General, and primarily are based upon the occurrence of significant acts of terrorism as part of an effort to coerce the civilian population of the United States or to influence the policy or affect the conduct of the United States Government by coercion. The nuclear property and accidental outage insurance programs, as discussed later in this section provide coverage for certified acts of terrorism.

Losses resulting from noncertified acts of terrorism are covered as a common occurrence, meaning that if noncertified terrorist acts occur against one or more commercial nuclear power plants insured by the insurer's of NMP2 within a 12-month period, such acts would be treated as one event and the owners of the currently licensed nuclear power plants in the United States would share one full limit of liability (currently $3.24 billion).

The Price Anderson Amendments Act mandates that nuclear power generators secure financial protection in the event of a nuclear accident. This protection must consist of two levels. The primary level provides liability insurance coverage of $375 million (the maximum amount available) in the event of a nuclear accident. If claims exceed that amount, a second level of protection is provided through a retrospective assessment of all licensed operating reactors. Currently, this "secondary financial protection" subjects each of the 104 presently licensed nuclear reactors in the United States to a retrospective assessment of up to $117.5 million for each nuclear incident, payable at a rate not to exceed $17.5 million per year. The Authority's interest in NMP2 could expose it to a maximum potential loss of $21.2 million per incident, through assessments of up to $3.2 million per year in the event of a serious nuclear accident at NMP2 or another licensed U.S. commercial nuclear reactor.

Constellation participates in the American Nuclear Insurers Master Worker Program that provides coverage for worker tort claims filed for radiation injuries. The policy provides a single industry aggregate limit of $200 million for occurrences of radiation injury claims against all those insured by this policy prior to January 1, 2003; $300 million for occurrences of radiation injury claims against all those insured by this policy between January 1, 2001 and January 1, 2010; and $375 million for occurrences of radiation injury claims against all those insured by this policy on or before January 1, 2010.

Constellation has also procured $500 million of primary nuclear property insurance and additional protection (including decontamination costs) of $1.25 billion of stand alone excess property insurance and a $1.0 billion shared excess policy for Nine Mile Point through the Nuclear Electric Insurance Limited (NEIL). Each member of NEIL, including the Authority, is also subject to retrospective premium adjustments in the event losses at other member facilities exceed accumulated reserves. For its share of NMP2, the Authority could be assessed up to approximately $3.3 million per loss.

The Authority has obtained insurance coverage from NEIL for the expense incurred in purchasing replacement power during prolonged accidental outages. Under this program, coverage would commence twelve weeks after any accidental outage, with reimbursement from NEIL at the rate of approximately $630,000 per week for the first 52 weeks, reduced to $504,000 per week for an additional 110 weeks for the purchase of replacement power, with a maximum limit of $88.2 million over a three-year period.

(8) Cash, and Cash Equivalents and Investments

(a) Authority

The Authority's investments are managed by an external investment manager and consist of three accounts; the Operating Fund, the Rate Stabilization Fund and the Construction Fund. The Operating Fund is managed to meet the liquidity needs of the Authority, the Rate Stabilization Fund is managed to maximize the return on investment and the Construction Fund is used to fund capital expenditures from the proceeds of the bonds. The Authority must maintain in the Rate Stabilization Fund an amount determined by the Authority from time to time in accordance with the Authority's bond resolution. In accordance with its agreements with the banks issuing letters of credit to secure the Authority's bonds, the Authority has agreed that such amount will not be less than $150 million. Additionally, the Authority is required to maintain compensating balances of $1.2 million.

The Authority's investment policy places limits on investments by issuer and by security type and addresses various risks described below. The Board of Trustees of the Authority may also specifically authorize, as it deems appropriate, other investments that are consistent with the Authority's investment objective. The Authority reviews its investment policy on an annual basis to ensure continued effectiveness.

Credit Risk: The Authority's permissible investments and related minimum credit ratings include U.S. Treasury and Federal Agency obligations (AAA), repurchase agreements (A-1), bankers' acceptances (AA- or Aa3), commercial paper (A1 or P-1), corporate notes (AA- or Aa3), master notes (AA- or Aa3) and asset backed securities (AAA), certificates of deposit (AA- or Aa3), mutual funds (AAAm or AAAm-G), investment contracts (AA- or Aa3), municipal obligations (AA- or Aa3), and variable rate notes (no credit rating limit). The Authority's investment policy prohibits investments involving complex derivatives, reverse repurchase agreements, auction rate securities and short selling and arbitrage related investment activity.

Concentration of Credit Risk: To address concentration of credit risk, the Authority's investment policies have established limits such that no more than 5% of the investment portfolio may be invested in the securities of any one issuer except as follows: (i) U.S. Treasury Obligations up to 100%; (ii) each Federal agency up to 35%; (iii) repurchase agreements up to 10% or $50 million; (iv) mutual funds up to 50% maximum; and, (v) investment contracts up to 10%.

Custodial Credit Risk: The Authority believes that custodial credit risk related to its investments is minimal, as it is the Authority's policy and practice, as stipulated in its Investment Guidelines, that investments be held by a third-party custodian who may not otherwise be a counter-party to the transactions, and that all securities are free and clear of any lien and held in a separate account, in the name of the Authority.

Custodial credit risk for cash deposits (including demand deposits, time deposits and certificates of deposit issued by a commercial bank) is the risk that in the event of a bank failure, the Authority's deposits may not be returned, either in part or in whole. The Authority's policy to address this risk requires that all demand deposits, time deposits and certificates of deposits issued by a commercial bank not having a long-term credit rating of Aa3/AA- or higher, be fully collateralized above the Federal Deposit Insurance Corporation coverage. Commercial banks with long-term credit ratings of Aa3/AA- or higher do not require collateralization unless otherwise required by the Chief Financial Officer.

As of December 31, 2010 and 2009, the Authority had deposits of $3 million and $12 million, of which approximately $2 million and $6 million, respectively, were not collateralized or were uninsured. Uncollateralized balances were primarily the result of amounts temporarily held pending investment or disbursement and changes to FDIC limits. Collateral on the remaining deposits was held in an account for the Authority at 102% of the available deposit balance.

Interest Rate Risk: The Authority's investment policy states that investments have maturities of 12 months or less, generally. Investment maturities may exceed 12 months provided that the maturity does not exceed the expected disbursement date of those funds, the total average portfolio maturity is one year or less and no individual maturity exceeds three years, with the exception of U.S. government obligations and investment contracts. As of December 31, 2010 and 2009, all of the Authority's investments had maturities of less than 12 months. The Authority's investment maturities are detailed in the chart below.

As of December 31, 2010, and 2009, the Authority had the following investments and maturities (amounts in thousands):

Deposit/investment type	2010 Fair value	Percent of portfolio	2010 Investment maturities Less than 3 months	3 months to 1 year
Short-term discount notes:				
Commercial paper	$ 267,038	56%	$ 156,830	110,208
Federal agencies	6,499	1	1,000	5,499
Money markets	202,003	42	202,003	—
Cash and collateralized deposits	3,486	1	3,486	—
Total	$ 479,026	100%	$ 363,319	115,707

Deposit/investment type	2009 Fair value	Percent of portfolio	2009 Investment maturities Less than 3 months	3 months to 1 year
Short-term discount notes:				
Commercial paper	$ 257,856	52%	$ 142,572	115,284
Federal agencies	9,399	2	400	8,999
Master notes/money markets	214,793	43	214,793	—
Cash and collateralized deposits	13,499	3	13,499	—
Total	$ 495,547	100%	$ 371,264	124,283

(b) LIPA

LIPA maintains a separate investment policy applicable to the long-term investments in the Nuclear Decommissioning Trusts (NDT) which is held to meet LIPA's obligation with respect to the eventual decommission of LIPA's 18% interest in the Nine Mile Point 2 nuclear facility. LIPA guidelines detail permissible investments and portfolio restrictions. LIPA reviews its investment policy at least annually to ensure that the value in the trusts in 2046, (the year in which decommissioning activities are scheduled to begin) will be sufficient to meet its decommissioning obligations.

(c) Credit Risk

LIPA's guidelines attempt to minimize risk by limiting permissible investments to include: obligations of the U.S. government and its agencies; corporate or other obligations with an A or better rating; mortgage obligations rated AA or higher; commercial paper with a rating of A1 or P1; certificates of deposit; Eurodollar certificates of deposit and bankers acceptances of domestic banks with A+ rating or better, short-term money market investment accounts that conform to the aforementioned permissible investments; and with respect to the LIPA's long-term NDT investment portfolio only, equity investments limited to portfolio funds of securities designed to replicate the overall market measured by the S&P 500 Index, and futures contracts on the S&P 500 Index. Within the NDT investment portfolio, the use of equity investments as a permissible investment is limited to a target exposure of 35% with a quarterly rebalancing within plus or minus 5%. The fixed income portion of the NDT investment portfolio must maintain an average credit rating of AA or better with no more than 30% of the portfolio invested in notes and bonds rated A and no more than 20% of the portfolio invested in municipal securities.

Concentration of Credit Risk: To address this risk, LIPA's investment policies have established limits such that no more than 5% of the portfolio may be invested in the securities of any one issuer with the exception of U.S. government and its agencies securities. In addition, no more than 25% of the portfolio may be invested in securities of issuers in the same industry.

Custodial Credit Risk: LIPA does not have a policy relative to custodial credit risk of its deposits, however, as a practical matter, LIPA defers to the policies of the Authority, as discussed above.

Interest Rate Risk: Due to the long-term nature of the NDT asset, interest rate risk is managed to track the Barclays Capital U.S. government/Credit Bond Index. The portfolio's duration is required to fall within a range of 20% below the duration of the index and 10% above the duration of the index.

As of December 31, 2010, and 2009, LIPA had the following investments (amounts in thousands):

Investment type		2010 Fair value	Percent of portfolio
Corporate notes and bonds	$	17,297	21%
Mortgage obligations		2,608	3
U.S. government and its agencies obligations		29,791	37
Money market		502	1
Commingled equity fund		30,374	38
Total	$	80,572	100%

Investment type		2009 Fair value	Percent of portfolio
Corporate notes and bonds	$	21,346	29%
Mortgage obligations		1,629	2
U.S. government and its agencies obligations		39,960	54
Money market		300	—
Commingled equity fund		11,313	15
Total	$	74,548	100%

The overall duration of the three individual accounts averaged 5.6 and 5.4 years at December 31, 2010 and 2009, respectively, and is within the limits described by LIPA's investment guidelines.

(9) Long-Term and Short-Term Debt

The Authority financed the cost of acquiring the T&D system and the refinancing of certain of LILCO's outstanding debt by issuing approximately $6.73 billion aggregate principal amount of Electric System General Revenue Bonds and Electric System Subordinated Revenue Bonds (collectively, the Bonds). In conjunction with the issuance of the Bonds, LIPA and the Authority entered into a Financing Agreement, whereby LIPA transferred to the Authority all of its right, title and interest in and to the revenues generated from the operation of the transmission and distribution system, including the right to collect and receive the same. In exchange for the transfer of these rights to the Authority, LIPA received the proceeds of the Bonds evidenced by a Promissory Note.

All of the Authority's bonds are secured by a Trust Estate as pledged under the Authority's Bond Resolution (the Resolution). The Trust Estate consists principally of the revenues generated by the operation of LIPA's transmission and distribution system and has been pledged by LIPA to the Authority.

The Authority's bond and note indebtedness and other long-term liabilities as of December 31, 2010 are comprised of the following obligations (amounts in thousands):

	Beginning balance	Accretion/ additions	Maturities	Refundings	Ending balance	Due within one year
Authority debt:						
Electric system general revenue bonds:						
Series 1998A	$ 288,389	6,861 (a)	77,620	—	217,630	81,800
Series 1998B	82,125	—	78,380	—	3,745	3,745
Series 2000A	409,780	22,819 (a)	30,825	—	401,774	31,260
Series 2001A	165,175	—	—	—	165,175	—
Series 2003B	262,510	—	12,245	—	250,265	12,800
Series 2003C	256,000	—	—	—	256,000	—
Series 2003 D	73,625	—	—	—	73,625	—
Series 2003 E-G	165,000	—	—	165,000	—	—
Series 2003 H-J	167,600	—	—	—	167,600	—
Series 2003 K	47,000	—	—	47,000	—	—
Series 2003 L-O	134,000	—	—	—	134,000	—
Series 2004A	200,000	—	—	—	200,000	—
Series 2006A	839,245	—	—	—	839,245	—
Series 2006B	96,955	—	—	—	96,955	—
Series 2006C	198,020	—	—	—	198,020	—
Series 2006D	326,925	—	665	—	326,260	690
Series 2006E	507,600	—	—	—	507,600	—
Series 2006F	514,495	—	—	—	514,495	81,325
Series 2008A	605,055	—	—	—	605,055	—
Series 2008B	149,340	—	—	—	149,340	—
Series 2009A	435,825	—	—	—	435,825	—
Series 2010A	—	193,325	—	—	193,325	—
Series 2010B	—	210,000	—	—	210,000	—
Subtotal	5,924,664	433,005	199,735	212,000	5,945,934	211,620
Electric system subordinate revenue bonds:						
Series 1-3	525,000	—	—	—	525,000	—
Series 8	51,705	—	25,225	—	26,480	26,480
Subtotal	576,705	—	25,225	—	551,480	26,480
LIPA debt:						
NYSERDA notes	155,420	—	—	—	155,420	—
Net unamortized discounts/ premiums and deferred amortization	(36,880)	(15,594)	—	(984)	(51,490)	—
Total bonds and notes, net of unamortized discounts /premiums	$ 6,619,909	417,411	224,960	211,016	6,601,344	238,100

	Beginning balance	Accretion/ additions	Maturities	Refundings	Ending balance	Due within one year
Other long-term liabilities:						
Deferred credits	$ 203,637	8,700	79,313	—	133,024	—
Borrowings	114,520	—	4,223	—	110,297	—
Claims and damages	20,207	2,268	827	—	21,648	—
Capital lease obligations	3,098,079	—	127,953	—	2,970,126	135,710
Total other long-term liabilities	$ 3,436,443	10,968	212,316	—	3,235,095	135,710

(a) Represents accretion of capital appreciation bonds

The Authority's bond and note indebtedness and other long-term liabilities as of December 31, 2009 are comprised of the following obligations (amounts in thousands):

	Beginning balance	Accretion/ additions	Maturities	Refundings	Ending balance	Due within one year
Authority debt:						
Electric system general revenue bonds:						
Series 1998A	$ 367,921	7,078 (a)	86,610	—	288,389	77,620
Series 1998B	154,485	—	72,360	—	82,125	78,380
Series 2000A	387,302	22,478 (a)	—	—	409,780	30,825
Series 2001A	165,175	—	—	—	165,175	—
Series 2001B-K	75,000	—	—	75,000	—	—
Series 2003A	19,895	—	19,895	—	—	—
Series 2003B	271,355	—	8,845	—	262,510	12,245
Series 2003C	256,000	—	—	—	256,000	—
Series 2003D-O	587,225	—	—	—	587,225	—
Series 2004A	200,000	—	—	—	200,000	—
Series 2006A	839,245	—	—	—	839,245	—
Series 2006B	96,955	—	—	—	96,955	—
Series 2006C	198,020	—	—	—	198,020	—
Series 2006D	327,565	—	640	—	326,925	665
Series 2006E	507,600	—	—	—	507,600	—
Series 2006F	514,495	—	—	—	514,495	—
Series 2008A	605,055	—	—	—	605,055	—
Series 2008B	149,340	—	—	—	149,340	—
Series 2009A	—	435,825	—	—	435,825	—
Subtotal	5,722,633	465,381	188,350	75,000	5,924,664	199,735
Electric system subordinate revenue bonds:						
Series 1-3	525,000	—	—	—	525,000	—
Series 7	156,100	—	—	156,100	—	—
Series 8	104,725	—	53,020	—	51,705	25,225
Subtotal	785,825	—	53,020	156,100	576,705	25,225

	Beginning balance	Accretion/ additions	Maturities	Refundings	Ending balance	Due within one year
LIPA debt:						
NYSERDA notes	$ 155,420	—	—	—	155,420	—
Net unamortized discounts/ premiums and deferred amortization	(41,745)	(1,672)	—	(6,537)	(36,880)	—
Total bonds and notes, net of unamortized discounts /premiums	$ 6,622,133	463,709	241,370	224,563	6,619,909	224,960
Other long-term liabilities:						
Deferred credits	$ 299,072	21,955	117,390	—	203,637	—
Borrowings	118,959	—	4,439	—	114,520	—
Claims and damages	19,089	2,800	1,682	—	20,207	—
Capital lease obligations	2,472,012	736,077	110,010	—	3,098,079	127,953
Total other long-term liabilities	$ 2,909,132	760,832	233,521	—	3,436,443	127,953

(a) Represents accretion of capital appreciation bonds

The Authority's schedule of capitalization for the years ended December 31, 2010 and 2009 is as follows (amounts in thousands):

Electric system	Maturity	Interest rate		Series	December 31, 2010	December 31, 2009
Electric system general revenue bonds:						
Serial bonds	December 1, 2011	5.500%	a	1998 A	$ 81,800	159,420
Capital appreciation bonds	December 1, 2012 to 2028	5.100% to 5.300%	a	1998 A	135,830	128,968
Serial bonds	April 1, 2011	4.500%	a	1998 B	3,745	82,125
Capital appreciation bonds	June 1, 2011 to 2029	5.420% to 5.950%	a	2000 A	401,774	409,781
Serial bonds	September 1, 2013 to 2014	4.600% to 4.700%	a, c	2001 A	745	745
Term bonds	September 1, 2027 to 2029	5.000% to 5.125%	a, c	2001 A	164,430	164,430
Serial bonds	June 1, 2011 to 2014	4.20% to 5.25%	a, c	2003 B	250,265	262,510
Serial bonds	September 1, 2013 to 2028	4.25% to 5.00%	a, c	2003 C	70,480	70,480
Term bonds	September 1, 2027 to 2033	5.00% to 5.25%	a, c	2003 C	185,520	185,520
Term bonds	December 1, 2029	0.25% to 0.40%	b, c	2003 D	73,625	73,625
Term bonds	December 1, 2029	0.25% to 0.28%	b, c	2003 E-G	—	165,000
Term bonds	December 1, 2029	0.28% to 0.43%	b, c	2003 H-J	167,600	167,600
Term bonds	December 1, 2029	0.330%	b, c	2003 K	—	47,000
Term bonds	December 1, 2029	0.25% to 0.39%	b, c	2003 L-O	134,000	134,000
Serial bonds	September 1, 2013 to 2025	3.80% to 4.875%	a, c	2004 A	33,900	33,900
Term bonds	September 1, 2029 to 2034	5.00% to 5.10%	a	2004 A	166,100	166,100
Serial bonds	December 1, 2016 to 2026	4.00% to 5.25%	a, c	2006A	839,245	839,245
Serial bonds	December 1, 2035	4.500%	a, c	2006B	4,240	4,240
Term bonds	December 1, 2035	5.000%	a	2006B	92,715	92,715
Term bonds	September 1, 2035	5.000%	a	2006C	198,020	198,020
Serial bonds	September 1, 2011 to 2025	4.00% to 5.00%	a, c	2006D	326,260	326,925
Serial bonds	December 1, 2017 to 2022	4.00% to 5.00%	a, c	2006E	507,600	507,600
Serial bonds	May 1, 2011 to 2028	4.00% to 5.00%	a, c	2006F	401,915	401,915

Electric system	Maturity	Interest rate		Series		December 31, 2010	December 31, 2009
Term bonds	May 1, 2030 to 2033	4.250%	a	2006F	$	112,580	112,580
Term bonds	May 1, 2031 to 2033	5.50% to 6.00%	a	2008A		605,055	605,055
Term bonds	April 1, 2019 to 2033	5.25% to 5.75%	a	2008B		149,340	149,340
Term bonds	April 1, 2014 to 2039	3.00% to 5.75%	a	2009A		435,825	435,825
Serial bonds	May 1, 2014 to 2015	2.50% to 5.00%	a	2010A		193,325	—
Term bonds	May 1, 2020 to 2041	4.85% to 5.85%	a	2010B		210,000	—
Electric system subordinated:							
Revenue bonds	May 1, 2033	0.34% to 0.36%	b, c	Series 1A-3A		275,000	275,000
	May 1, 2033	0.26% to 0.31%	b, c	Series 1B-3B		250,000	250,000
	April 1, 2011	4.00% to 5.00%	a	Series 8		26,480	51,705
Total general and subordinated revenue bonds						6,497,414	6,501,369
Commercial paper notes		0.29% to 0.35%	b	CP-1		100,000	100,000
		0.26% to 0.32%	b	CP-3		100,000	100,000
						200,000	200,000
NYSERDA Financing notes:							
Pollution control revenue bonds	March 1, 2016	5.150%	a	1985 A,B		108,020	108,020
Electric facilities revenue bonds	November 1, 2023	5.300%	a	1993 B		29,600	29,600
	October 1, 2024	5.300%	a	1994 A		2,600	2,600
	August 1, 2025	5.300%	a	1995 A		15,200	15,200
Total NYSERDA financing notes						155,420	155,420
Unamortized premium and deferred amortization						(51,490)	(36,880)
Total long-term debt						6,801,344	6,819,909
Less current maturities and short-term debt						438,100	424,960
Long-term debt						6,363,244	6,394,949
Net assets						377,169	319,720
Total capitalization					$	6,740,413	6,714,669

a Fixed rate.
b Variable rate (rate presented is as of December 31, 2010).
c Certain bonds of this series are subject to interest rate exchange agreements – see note 4.

The debt service requirements for the Authority's bonds (excluding commercial paper notes) as of December 31, 2010, are as follows (amounts in thousands):

Due		Principal	Interest	Net swap payments	Total
2011	$	238,100	277,463	28,028	543,591
2012		278,025	278,749	16,516	573,290
2013		176,060	277,988	7,795	461,843
2014		280,720	270,666	7,097	558,483
2015		289,585	259,431	7,097	556,113
2016 – 2020		1,194,355	1,171,754	15,116	2,381,225
2021 – 2025		1,381,130	927,980	16,882	2,325,992
2026 – 2030		1,421,010	644,456	11,052	2,076,518
2031 – 2035		1,514,315	242,743	—	1,757,058
2036 – 2040		126,695	57,672	—	184,367
2041		110,000	3,218	—	113,218
		7,009,995	4,412,120	109,583	11,531,698
Unamortized discounts/premiums		(51,490)	—	—	(51,490)
Unaccreted interest on capital appreciation bonds		(357,161)	—	—	(357,161)
Total	$	6,601,344	4,412,120	109,583	11,123,047

Future debt service on the variable rate bonds and floating rate portion of any floating-to-fixed rate swaps use an assumed rate of 1.50% for 2011; 3.00% for 2012; 4.00% for 2013 through 2015; and 4.50% thereafter. For bonds subject to floating to fixed rate swap agreements, the "net swap payments" represent the fixed swap rate payment net of the assumed future variable rate swap receipts for each agreement.

(a) Electric System General Revenue Bonds

2010

In May 2010, the Authority issued $193 million of its Electric System General Revenue Bonds, Series 2010A. The proceeds of these fixed rate bonds, including the premium of $20 million, were used to redeem $212 million of outstanding insured variable rate securities in a current refunding and to pay bond issuance costs. The refunding produced an approximate $28 million net present value savings. The 2010A bonds have an average life of 4.5 years and an all-in cost of 2.50%. The refunding produced an approximate $28 million net present value savings.

Also, in May 2010, the Authority issued $210 million of its Electric System General Revenue Bonds, Series 2010B. The 2010B bonds are taxable Build America Bonds and the Authority receives an interest subsidy from the federal government equal to 35% of the interest paid. The proceeds of these fixed rate bonds outstanding are used to finance the on-going capital program. The 2010B bonds have an average life of 22 years and an all-in cost of 3.75%.

2009

In January 2009, the Authority issued $436 million of its Electric System General Revenue Bonds, Series 2009A. The proceeds of these fixed rate bonds, including the premium of $9 million, were used to redeem approximately $231 million of outstanding insured variable rate securities in a current refunding and to pay bond issuance costs totaling $3 million. The remaining proceeds were used to finance the on-going capital program. The refunding produced an approximate $45 million net present value savings. The 2009A bonds have an average life of 20 years and an all-in cost of 5.50%.

(b) Interest Rate Swap Agreements

The Authority has entered into several interest rate swap agreements with various counterparties to modify the effective interest rate on outstanding debt. For a further discussion, see note 4.

(c) Commercial Paper Notes

The Supplemental Bond Resolution authorizes the issuance of Commercial Paper Notes, Series CP-l through CP-3 (Notes) up to a maximum amount of $300 million. The aggregate principal amount of the Notes outstanding at any time may not exceed $300 million. In connection with the issuance of the Notes, the Authority has entered into a Letter of Credit and Reimbursement Agreement which was renegotiated in 2006. Under the terms of the renegotiated Letter of Credit and Reimbursement Agreement, $250 million expires June 15, 2011 and the remaining $50 million expires on December 15, 2015, subject to the right of early termination by the bank on June 15, 2012. The Notes do not have maturity dates of longer than 270 days from their date of issuance and as Notes mature, the Authority continually replaces them with additional Notes.

The Authority's short-term indebtedness as of December 31, 2010 and 2009 is comprised of the following obligations (amounts in thousands):

		2010			
		Beginning balance	**Issuances**	**Retirements**	**Ending balance**
Short-term debt – CP-1	$	100,000	210,200	(210,200)	100,000
Short-term debt – CP-3		100,000	608,100	(608,100)	100,000
	$	200,000	818,300	(818,300)	200,000

		2009			
		Beginning balance	**Issuances**	**Retirements**	**Ending balance**
Short-term debt – CP-1	$	100,000	230,600	(230,600)	100,000
Short-term debt – CP-3		100,000	617,000	(617,000)	100,000
	$	200,000	847,600	(847,600)	200,000

(d) Fair Values of Long-Term Debt

The fair values of the Authority's long-term debt as of December 31, 2010 and 2009 were as follows (amounts in thousands):

		December 31, 2010	December 31, 2009
Electric System General Revenue Bonds, Series 1998 A	$	233,769	313,580
Electric System General Revenue Bonds, Series 1998 B		3,781	83,002
Electric System General Revenue Bonds, Series 2000 A		455,237	475,915
Electric System General Revenue Bonds, Series 2001 A		165,236	166,488
Electric System General Revenue Bonds, Series 2003 B		271,566	290,276
Electric System General Revenue Bonds, Series 2003 C		253,990	262,348
Electric System General Revenue Bonds, Series 2003 D		73,625	73,625
Electric System General Revenue Bonds, Series 2003 E-G		—	165,000
Electric System General Revenue Bonds, Series 2003 H-J		167,600	167,600
Electric System General Revenue Bonds, Series 2003 K		—	47,000
Electric System General Revenue Bonds, Series 2003 L-O		134,000	134,000
Electric System General Revenue Bonds, Series 2004 A		195,432	202,288
Electric System General Revenue Bonds, Series 2006 A		862,530	871,972
Electric System General Revenue Bonds, Series 2006 B		91,131	95,674
Electric System General Revenue Bonds, Series 2006 C		186,856	196,262
Electric System General Revenue Bonds, Series 2006 D		336,821	336,568
Electric System General Revenue Bonds, Series 2006 E		536,783	537,783
Electric System General Revenue Bonds, Series 2006 F		517,784	530,211
Electric System General Revenue Bonds, Series 2008 A		626,876	649,220
Electric System General Revenue Bonds, Series 2008 B		159,235	162,409
Electric System General Revenue Bonds, Series 2009 A		459,240	468,094
Electric System General Revenue Bonds, Series 2010A		212,238	—
Electric System General Revenue Bonds, Series 2010B		185,891	—
Electric System Subordinated Revenue Bonds, Series 1-3 and 1-6		525,000	525,000
Electric System Subordinated Revenue Bonds, Series 8C		—	25,487
Electric System Subordinated Revenue Bonds, Series 8F		26,735	27,595
NYSERDA Notes		156,430	156,368
Total	$	6,837,786	6,963,765

(10) Retirement Plans

The Authority participates in the New York State Employees' Retirement System (the System), which is a cost-sharing, multi-employer, and public employee retirement system. The plan benefits are provided under the provisions of the New York State Retirement and Social Security Law that are guaranteed by the State Constitution and may be amended only by the State Legislature. For full time employees, membership in and annual contributions to the System are required by the New York State Retirement and Social Security Law. The System offers plans and benefits related to years of service and final average salary, and, effective January 1, 2010 benefits for new members vest after ten years of accredited service, all others generally vested after five years.

Members of the System with less than 10 years of service or 10 years of membership contribute 3% of their gross salaries and the Authority pays the balance of the annual contributions for these employees. Effective October 1, 2000, members of the System with at least 10 years of service or membership no longer contribute 3% of their gross salaries. The Authority pays the entire amount of the annual contributions of these employees. Effective January 1, 2010, all new members contribute 3% of their gross salaries for their entire career.

Under this plan, the Authority's required contributions and payments made to the System were approximately $1.1 million, $572,000, and $713,000, for the years ended December 31, 2010, 2009, and 2008, respectively. Contributions are made in accordance with funding requirements determined by the actuary of the System using the aggregate cost method.

The State of New York and the various local governmental units and agencies which participate in the Retirement System are jointly represented, and benefits for Authority employees are not separately computed. The New York State Employees' Retirement System issues a publicly available financial report. The report may be obtained from the New York State and Local Retirement Systems, 110 State Street, Albany, New York 12244.

(11) Postemployment Healthcare Plan

(a) Plan Description

The Authority is a participating employer in the New York State Health Insurance Program (NYSHIP) which is administered by the State of New York as an agent multiple employer defined benefit plan. Under the plan, the Authority provides certain health care for eligible retired employees and their dependents. Article XI of the New York State Civil Service Law assigns the authority to NYSHIP to establish and amend the benefit provisions of the plans and to establish maximum obligations of the plan members to contribute to the plan. The Authority's Board is authorized to establish the contribution rates of its employees and retirees below those set by Civil Service Law. Participation in the NYSHIP program provides for employees and/or their dependents to become eligible for these benefits at 55 years of age when the employee has five years of State service. In calculating the five year service requirement, all of the employee's service need not be with the Authority, but may be a composite of New York State service elsewhere, with a minimum of one year with the Authority. Employees with no prior State service must work a minimum of five years before they and their dependents are eligible for the retirement medical benefits. Eligible retirees contribute 10% of the cost of single coverage and 25% the cost of dependent coverage for health insurance benefits. Participants include approximately 96 employees and retired and/or spouses of retired employees who were eligible to receive these benefits at December 31, 2010. NYSHIP does not issue a stand-alone financial report and NYSHIP's agent activities are included within the financial statements of the State of New York.

The Authority accounts for its OPEB obligations, in accordance with GASB Statement No. 45, *Accounting and Financial Reporting for Post Employment Benefits Other Than Pensions. Actuarial* valuations involve estimates of the value of reported amounts and assumptions about the probability of events in the future. Examples include assumptions about employment mortality and the healthcare cost trend. Amounts determined regarding the annual required contributions of the employer are subject to continual revision as actual results are compared to past expectations and new estimates are made about the future.

The Authority's annual OPEB cost for the plan is calculated based on the Annual Required Contribution (ARC), an amount actuarially determined in accordance with the parameters of GASB Statement No. 45. GASB 45 does not require that an employer actually fund its ARC, but allows for the financing of these benefits on a pay-as-you-go basis. Since the Authority expensed the entire prior service cost in 2007, the ARC in future periods represents a level of funding that, if paid on an ongoing basis, is projected to cover normal cost each year, actuarial assumptions and plan changes, and interest on the unfunded actuarial liability. Amounts "required" but not actually set aside to pay for these benefits are accumulated as part of the Net OPEB Obligation (which was $18 million at December 31, 2010), and as the Authority has not actually funded the "required" amount, future valuations may produce larger ARCs. The current period ARC is approximately $2.2 million as detailed in the chart.

(b) Funding

The contribution requirements (funding) of the Authority's Net OPEB obligation are at the discretion of management and the Board of Trustees. The Net OPEB obligation is paid on a pay-as-you-go basis. The Authority has not funded a qualified trust or its equivalent.

(c) Actuarial Methods and Assumption

Projections of benefits for financial reporting purposes are based on the substantive plan (the plan as understood by the employer and plan members) and include the types of benefits provided at the time of each valuation. The actuarial methods and assumptions used include techniques that are designed to reduce short-term volatility in actuarial accrued liabilities and the actuarial value of assets, consistent with the long-term perspective of the calculations. For 2010 actuarial valuation, the projected unit credit actuarial cost method was used. The actuarial assumptions included a 3.75% investment rate of return (net of administrative expenses) and an annual healthcare cost trend rate of 10% (net of administrative expenses) including inflation, declining 1% each year to an ultimate trend rate of 5%. Both rates include a 3% inflation assumption.

(d) OPEB Status and Funding Progress

The OPEB obligation, which is included in deferred credits, and the funded status of the plan as of December 31, 2010 and 2009 is as follows (amounts in thousands):

		2010	2009
Annual OPEB cost:			
Annual required contribution (ARC):			
Normal cost	$	1,482	1,412
Amortization payment		15,718	13,854
Interest to the end of the year		642	570
Total		17,842	15,836
ARC adjustment		(16,190)	(14,245)
Interest on net OPEB obligation		590	515
Annual OPEB cost	$	2,242	2,106
Net OPEB obligation:			
Net OPEB obligation at beginning of fiscal year	$	15,714	13,731
Annual required contribution:			
Annual OPEB cost		2,242	2,106
Employer contribution:			
Payments for retirees during the year		(131)	(123)
to a trust		—	—
Net OPEB obligation at end of fiscal year	$	17,825	15,714

Actuarial valuation date		2010	2009
Actuarial value of assets	$	—	—
Accrued actuarial liability (AAL)		18,688	16,680
Unfunded AAL		18,688	16,680
Funded ratio		—%	—%
Covered payroll	$	10,576	10,980
UAAL as % covered payroll		176.7%	151.9%

(12) Commitments and Contingencies

(a) Power Supply Agreement (PSA)

The PSA provides for the sales to the Authority by KeySpan of all of the capacity, energy and, ancillary service output from the oil and gas-fired generating plants on Long Island formerly owned by LILCO. Such sales of capacity and energy are made at cost-based wholesale rates regulated by the Federal Energy Regulatory Commission (FERC). The rates may be modified in accordance with the terms of the PSA for: (i) agreed upon labor and expense indices applied to the base year; (ii) a return of and return on net capital additions, which require approval by the Authority; and (iii) reasonably incurred expenses that are outside of the control of KeySpan. The PSA rates were reset in 2009, in accordance with the PSA agreement and as approved by FERC, and will continue through May 2013 at which time the Authority has the option to extend the PSA at newly negotiated terms for a period of up to 15 years. The rates are adjusted annually in accordance with the formula established in the PSA. The annual capacity charge in 2010 and 2009 was approximately $431 million and $422 million, respectively, and the variable charge remained unchanged at $0.90/Mwh of electric power generated by the plants.

The PSA provides incentives and penalties for up to $4 million annually to maintain the output capability of the facilities, as measured by annual industry-standard tests of operating capability, and to maintain/or make capital improvements which benefit plant availability. The performance incentives averaged approximately $3 million in 2010 and 2009.

(b) Purchased Power and Transmission Agreements Assumed from LILCO

As a result of the merger with LILCO, the Authority became party to power purchase agreements (PPAs) with Independent Power Producers (IPPs) and the New York Power Authority (NYPA) for electric generating capacity. Certain of these agreements have been renegotiated by the Authority or modified to comply with market rules instituted by the New York Independent System Operator (NYISO).

Under the terms of a 1989 agreement with NYPA, which will expire in 2015, the Authority purchases power from a pumped storage plant in upstate New York at tariff rates established by NYPA. Under the terms of a 1994 agreement with NYPA which will expire in April 2020, the Authority purchases the electric energy produced at the NYPA facility located within the service territory at Holtsville, New York. The Authority is required to reimburse NYPA for the minimum debt service payments and to make fixed nonenergy payments associated with operating and maintaining the plant.

The Authority also became party to contracts with NYPA and Con Edison for firm transmission (wheeling) capacity in connection with the pumped storage PPA, as well as a contract with NYPA associated with a transmission cable that was constructed, in part, for the benefit of the Authority. With the inception of the NYISO on November 18, 1999, these transmission contracts were provided with “grandfathered rights” status. The Authority was provided with the opportunity to convert its grandfathered rights for Existing Transmission Agreements (ETAs) into Transmission Congestion Contracts (TCCs). Although the Authority has converted its ETA’s into TCCs, the Authority will continue to pay all transmission charges per the ETAs. In return, the Authority receives revenues from congestion charges collected by the NYISO. All such charges and revenue are considered components of or reductions to fuel and purchased power costs.

With respect to PPAs entered into with the IPPs, the Authority is obligated to purchase all the energy they make available to the Authority. However, LIPA has no obligation to the IPPs if they fail to deliver energy.

As provided by the Authority's tariff, the costs of all of the facilities noted above except for those subject to the PSA will be includable in the calculation of Fuel and Purchased Power Cost. As such, these costs will be recoverable through the FPPCA.

The following table represents the Authority's commitments under the PPAs and transmission contracts assumed from LILCO, as renegotiated or modified (amounts in thousands):

		PPA	Firm transmission	IPPs*	Total
Years ended:					
2011	$	32,826	21,160	64,800	118,786
2012		33,062	22,310	65,400	120,772
2013		33,682	23,290	53,600	110,572
2014		33,225	23,390	53,400	110,015
2015		33,453	23,070	57,400	113,923
2016 through 2020		149,890	10,580	15,000	175,470
2021 through 2025		—	33,880	—	33,880
2026 through 2030		—	28,080	—	28,080
2031 through 2035		—	29,270	—	29,270
Subtotal		316,138	215,030	309,600	840,768
Less imputed interest		69,281	5,619	42,300	117,200
Total	$	246,857	209,411	267,300	957,968

* Assumes full performance by NYPA and the IPPs.

(c) Additional Power Purchase Agreements

The Authority has entered into power purchase agreements (PPAs) with several private companies to develop and operate generating units at sites throughout Long Island. Generally, the PPAs provide for the Authority to purchase 100% of the capacity (and associated energy as needed), for the term of each contract, which vary in duration up to 30 years from contract initiation date.

In accordance with the provisions of FASB ASC 840 *Leases* (previously FASB Emerging Issues Task Force Issue No. 01-08, *Determining Whether an Arrangements is a Lease* and SFAS No. 13, *Accounting for Leases*), certain generating units have been accounted for as capitalized lease obligations. Other units which do not meet the criteria for capitalization under FASB ASC 840 are being accounted for as operating leases.

During 2010, the Authority also entered into an agreement with the owners of a facility located in PJM-ISO for a long-term capacity purchase which commenced on June 1, 2010.

During 2009, the Authority began to acquire 286 MW from a 326MW plant that was constructed on Long Island. The Authority also purchases up to 345 MW of capacity and varying amounts of energy from a portfolio of facilities located in New England. This power is transmitted to Long Island via an undersea high voltage cable running between Connecticut and Long Island pursuant to a long-term firm transmission capacity purchase agreement.

The Authority also entered into two contracts for the purchase of renewable energy from off-Island sources which commenced in 2009. There are two additional contracts for power to be produced by solar photovoltaic power plants to be constructed in 2011 at various sites on Long Island (these contracts are assumed completed in 2011 and are included in the table below).

The following table represents the minimum payments under these various capacity and/or energy contracts (amounts in thousands):

		Capitalized leases	Operating leases
Minimum lease/rental payments:			
2011	$	293,896	145,346
2012		295,282	157,562
2013		296,322	160,192
2014		297,852	162,775
2015		299,332	165,526
2016 through 2020		1,336,763	813,402
2021 through 2025		1,120,374	407,818
2026 through 2030		498,776	416,658
2031 through 2034		40,212	22,112
Total		4,478,809	2,451,391
Less imputed interest		1,508,683	884,227
Net present value	$	2,970,126	1,567,164

(d) Office Lease

The Authority's office lease agreement terminates April 30, 2011. The Authority has entered into a new office lease agreement which will commence upon approval from the Office of the New York State Comptroller (OSC). The termination date of the new lease is April 30, 2024. If this lease agreement does not receive OSC approval by May 1, 2011 the new lease agreement will expire and the Authority will become a hold over tenant whereby rent expense is paid on a monthly basis.

Rental expense for the office lease amounted to approximately $1.8 million and $1.7 million for the years ended December 31, 2010 and 2009, respectively.

(e) Insurance Programs

The Authority's insurance program is comprised of a combination of policies from major insurance companies, self-insurance and contractual transfer of liability, including naming the Authority as an additional insured and indemnification.

The Authority has purchased Workers' Compensation insurance from the New York State Insurance Fund to provide coverage for claims arising from employee injuries. Liability related to construction projects and similar risks is transferred through contractual indemnification and compliance with Authority insurance requirements. The Authority also has various insurance coverages on its interest in Nine Mile Point Nuclear Power Station, Unit 2 as disclosed in detail in note 7.

The Authority is self insured for property damage to its transmission and distribution system and up to $3 million for general liability, including automobile liability. The Authority purchased commercially available excess general liability insurance for claims above the $3 million self insurance provision.

(13) Legal Proceedings

(a) Authority to Set Rates

Under current State law, the Board of Trustees of the Authority is empowered to set rates for electric service in the Service Area without being required by law to obtain the approval of the PSC or any other State regulatory body. However, in connection with the approval of the LIPA/LILCO Merger by the PACB in 1997, the Authority agreed that it would comply with the condition imposed by the PACB and not impose any permanent increase, nor extend or reestablish any portion of a temporary rate increase, in average customer rates over a 12-month period in excess of 2.5% without approval of the PSC, following a full evidentiary hearing.

Legislation was unanimously passed by the New York State Legislature in June 2008, which would amend the LIPA Act and the State Public Service Law to require the approval by the PSC of an increase in LIPA's average customer rates exceeding 2.5% over a 12-month period or to extend or reestablish any portion of a temporary rate increase exceeding 2.5%. Were such legislation to become law, the Authority would have to notify the PSC of any proposed rate increase, extension or re-establishment exceeding 2.5% of average rates over a 12-month period. Approval of any such request by the PSC would require a full evidentiary hearing by the PSC. The proposed legislation was vetoed on September 4, 2008 by Governor Paterson and therefore has not been enacted into law. A revised version of the 2008 bill was introduced in both the Assembly and Senate in 2009. The Assembly passed the bill on June 16, 2009, however, the Senate did not take any further action in 2009 and the legislative session ended without the bill being passed. A further revised bill was introduced in both the Assembly and Senate in 2010. On March 10, 2010, the Assembly passed the bill. However, to date, the Senate has not taken any further action. The Authority cannot predict whether this bill will become law or whether other similar legislation may be introduced and acted upon in the future.

(b) Environmental

In connection with the LIPA/LILCO Merger (the Merger), KeySpan and the Authority entered into Liabilities Undertaking and Indemnification Agreements which, when taken together, provide, generally, that environmental liabilities will be divided between KeySpan and the Authority on the basis of whether they relate to assets transferred to KeySpan or retained by the Authority as part of the Merger. In addition, to clarify and supplement these agreements, KeySpan and the Authority also entered into an agreement to allocate between them certain liabilities, including environmental liabilities, arising from events occurring prior to the Merger and relating to the business and operations to be conducted by the Authority after the Merger (the Retained Business) and to the business and operations to be conducted by KeySpan after the Merger (the Transferred Business).

National Grid, who subsequently purchased KeySpan in 2007, is now responsible for all liabilities arising from all manufactured gas plant operations (MGP Sites), including those currently or formerly operated by National Grid or any of its predecessors, whether or not such MGP Sites related to the Transferred Business or the Retained Business. In addition, National Grid is liable for all environmental liabilities traceable to the Transferred Business and certain scheduled environmental liabilities. Environmental liabilities that arise from the nonnuclear generating business may be recoverable by National Grid as part of the capacity charge under the PSA. The Authority is responsible for all environmental liabilities traceable to the Retained Business and certain scheduled environmental liabilities.

Environmental liabilities other than those related to MGP sites that existed as of the date of the Merger that are untraceable, including untraceable liabilities that arise out of common and/or shared services have been allocated 53.6% to LIPA and 46.4% to National Grid, as provided for in the Merger.

(c) Environmental Matters Retained by the Authority

Superfund Sites – Under Section 107(a) of the federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA, also commonly referred to as the Superfund Legislation), parties who generated or arranged for disposal of hazardous substances are liable for costs incurred by the Environmental Protection Agency (EPA) or others who are responding to a release or threat of release of the hazardous substances.

Port Washington Landfill – LILCO is a PRP at this 54-acre municipal solid waste landfill located in the Town of North Hempstead. The landfill operated from 1973 to 1983. Since January 2001, LILCO and 11 other parties have been signing tolling agreements with the New York State Attorney General to extend the statute of limitations under CERCLA. The current tolling agreement expires on June 25, 2011. Six of the 11 tolling agreement PRPs, including LILCO, have formed a Joint Defense Group (JDG) that acts as one with respect to dealing with the Attorney General. The Attorney General is seeking to recover Environmental Quality Bond Act funds advanced to the Town of North Hempstead so it could properly close out the site with oversight by the New York State Department of Environmental Conservation (DEC). The landfill has been remediated and this matter is only concerned with cost recovery. The JDG is in negotiations with the Attorney General to resolve this matter. The Authority does not believe that its share of any settlement agreement will have a material adverse effect on its financial position, cash flows or results of operations.

(d) Environmental Matters which may be Recoverable from the Authority by KeySpan Through the PSA

Asharoken – In March 1996, the Village of Asharoken (the Village) filed a lawsuit against LILCO in the New York Supreme Court, Suffolk County (Incorporated Village of Asharoken, New York, et al.

v. Long Island Lighting Company). Although the Village's negligence claims were dismissed, the nuisance causes of action remained at issue. Specifically, the Village sought injunctive relief based upon allegations that the design and construction of the Northport Power Plant upset the littoral drift of sand in the area, thereby causing beach erosion. In a related matter, certain individual residents of the Village commenced an action in New York Supreme Court, Suffolk County seeking similar relief (Sbarro v. Long Island Lighting Company). The cases were tried jointly before a judge without a jury. The trial was completed in December 2002 and the parties filed post-trial briefs in March 2003. The judge dismissed the case after reviewing the existing and supplemental record. The Village subsequently filed a notice of appeal of this decision and, on December 22, 2008, the Appellate Division unanimously affirmed the judge's dismissal of the Village of Asharoken's lawsuit against LILCO.

Despite the decision of the Appellate Division, the U.S. Army Corps of Engineers, as a condition of an existing permit, required National Grid to deposit 45,000 cubic yards of sand every three years, starting in 2010, on beaches within the Village. The Authority and National Grid complied with this requirement in 2010 and intend to comply in 2013 and thereafter subject to future negotiations and potential relief. The Authority does not believe that this will have a material adverse effect on its financial position, cash flows or results of operations.

(e) Asbestos Proceedings

Litigation is pending in State Court against the Authority, LILCO, KeySpan and various other defendants, involving thousands of plaintiffs seeking damages for personal injuries or wrongful death allegedly caused by exposure to asbestos. The cases for which the Authority may have financial responsibility involve employees of various contractors and subcontractors engaged in the construction or renovation of one or more of LILCO's six major power plants. These cases include extraordinarily large damage claims, which have historically proven to be excessive. The actual aggregate amount paid to plaintiffs alleging exposure to asbestos at LILCO power plants over the years has not been material to the Authority. Due to the nature of how these cases are litigated, it is difficult to determine how many of the remaining cases that have been filed (or of those that will be filed in the future) involve plaintiffs who were exposed to asbestos at any of the LILCO power plants. Based upon experience, it is likely that the Authority will have financial responsibility in a significantly smaller percentage of cases than are currently pending (or which will be filed in the future) involving plaintiffs who allege exposure to asbestos at any of the LILCO power plants.

(f) Future Environmental Compliance Obligations

The Authority, through its contractual obligations to KeySpan under the PSA and the MSA, and other Independent Power Producers and transmission cable operators, under various power purchase agreements (PPAs), may be subject to the cost of compliance with various current and potential future environmental regulations as promulgated by the federal government and by state and local governments with respect to environmental matters, such as emission of air pollutants, greenhouse gases, cooling water for generation, electromagnetic fields, the handling and disposal of toxic substances and hazardous and solid wastes, the handling and use of chemical products, and the handling and storage of fossil fuels. Electric utility companies generally use or generate a range of pollutants, potentially hazardous products and by-products that are the focus of such regulation. The

Authority is also subject to state laws regarding environmental approval and certification of proposed major transmission facilities.

The Clean Air Act Amendments of 1990 (1990 Amendments) limit emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx), and other pollutants. The EPA allocates annual SO_2 emissions allowances to each of the PSA units based on historical output. NOx emissions are regulated on a regional level through the NOx State Implementation Plan, and are also controlled through allowance allocations. Generating units under the various PPAs and the PSA units are expected to continue to achieve cost effective compliance with these emission control requirements through the use of allocated allowances, capital expenditures, the use of natural gas fuel, and/or the purchase of emission allowances as necessary. Generating units may be required to purchase additional allowances above their unit's allocations, or make other expenditures, based on changes in plant operation, fuel prices, or more restrictive regulations.

In March 2005, the Federal Clean Air Interstate Rule (CAIR) was promulgated, requiring further reductions of SO_2 and NOx emissions to reduce ozone and fine particulate matter formation in the eastern United States. The State of New York has adopted rules to carry out this program in which compliance requirements for NOx reduction began in 2009. As part of the Agreement and Waiver with National Grid (the Agreement), National Grid, subject to the terms of the Agreement, is installing additional NOx controls, called Separated Over Fired Air (SOFA), on all the units at Northport and Port Jefferson, to reduce NOx emissions. Current projections of PSA unit operations indicate that the PSA units should be able to comply by using their existing annual allowance allocations and with these new controls. Subsequently, in 2008 the D.C. Circuit Court remanded without vacatur EPA's CAIR Rule. In response, on July 6, 2010, EPA proposed the Transport Rule which will replace CAIR when finalized. The planned SOFA installation on the four Northport and two Port Jefferson units, as well as a contemplated installation of water injection on additional Holtsville combustion turbines, is expected to make significant reductions to NOx emissions sufficient to comply with the new rules. Compliance with new SO_2 limits will likely be achieved with the existing SO_2 allowance bank and fuel switching. However, additional controls or allowance purchases may be needed depending on the level of reductions ultimately required in the final rule.

In 2009 the DEC, in compliance with the EPA's Regional Haze Rule, issued a State Implementation Plan that specified how reductions in visibility-impairing pollutants would improve visibility in certain designated areas in the Northeastern United States. While the EPA has stated that participation in the Transport Rule will meet requirements, the DEC has proposed its own regulations, including the Best Available Retrofit Technology (BART) requirements. The rule required affected sources to submit a plan to the DEC in October 2010, demonstrating how the sources would comply with the rule. The PSA units' plan documented that SOFA on these five units, as well as the consumption of low sulfur fuel, are BART technologies for these sources. The DEC is currently waiting for EPA approval. Another rule issued in 2005, the Clean Air Mercury Rule (CAMR) had set new limits for mercury emissions from coal-fueled plants; as such, it does not apply to the PSA units, although it may impact the pricing of purchased power. The rulemaking process also considered regulating nickel emissions from oil fired units which would have affected some PSA units and units under PPAs that burn oil, but ultimately did not. On February 8, 2008, the D.C. Circuit vacated the CAMR regulation and remanded the regulation back to EPA.

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As a result of the D.C. Circuit's vacating the CAMR Rule, EPA is required to determine at what level to regulate Hazardous Air Pollutants from oil and coal fired electric generating units (the Utility MACT Rule), and required stack testing at two Northport units and one Port Jefferson unit to be completed by September 2010. EPA will evaluate data received from testing in order to set emission levels, therefore at this point it is not possible to determine what, if any, additional controls may be required at Northport and Port Jefferson, or other units.

In 2005, New York State joined the Regional Greenhouse Gas Initiative (RGGI) for the purpose of capping and then reducing greenhouse gas emissions from power plants. New York State adopted its final regulation in 2008 to implement the requirements of RGGI and to auction most of the CO2 allowances comprising the New York share of the regional cap. Regional auctions are being conducted on a quarterly basis. The majority of the power plants which are under long-term contract to the Authority and are in the RGGI region are participating in the auctions, with most having an agreement for cost recovery from the Authority. Several plants are not able to claim recovery of these costs from the Authority, but are still required to comply. The Authority includes such costs as a component of its fuel and purchased power, and as such these costs are subject to recovery as provided under the FPPCA. These costs totaled approximately $11 million and $16 million in 2010 and 2009, respectively.

Section 185 of the Clean Air Act requires states to collect fees from major sources in those areas defined as severe or extreme ozone nonattainment areas that fail to come into compliance with the ozone National Ambient Air Quality Standards (NAAQS) by the dates provided under the Clean Air Act. Based on EPA guidance, it is expected that the fees, initially set at $5,000 per ton of NOx and volatile organic compounds emissions (adjusted annually from 1991 by the consumer price index), will be based on those emissions that exceed 80% of a plant's baseline in year 2007 for sources located in the New York metropolitan area, including on Long Island, or possibly another period representative of a source's normal operations. Several of the PSA units have exceeded the threshold in past years; however, the DEC has not chosen enforcement. Instead, the DEC has submitted to the EPA a demonstration that the area has achieved attainment with the ozone standard and therefore collection of 185 fees is not required. The State of New York is also in the process of developing its fine particulate matter and 8-hr ozone State Implementation Plans. While not yet proposed, the State intends to revise its existing regulations to require that sources of particulate matter sized 2.5 microns or smaller (PM2.5) with the potential to emit 100 tons per year will be required to perform case by case Reasonable Available Control Technology (RACT) analyses, and the State might also develop more stringent NOx RACT requirements. In addition, in 2007, member states of the Ozone Transport Commission determined that additional NOx emission reductions would be required from electric generating facilities during High Electric Demand Days. DEC has revised its NOx RACT regulations, significantly reducing the target NOx emission rates for the steam units. This will greatly lower the compliance margin generated by the steam units that allow for the operation of the combustion turbines. The planned installation of SOFA on the four Northport and two Port Jefferson units, as well as the contemplated installation of water injection on additional Holtsville combustion turbines is expected to make significant reductions that should be sufficient to comply with the new rules.

In 2010, the EPA finalized the 1-hr NO2 National Ambient Air Quality Standard. Originally, the standard was focused on levels of NO2 found near major highways and roadways in urban areas. However, since this is an ambient air quality standard, regulatory agencies will be evaluating the impact of stationary sources. This will particularly impact diesel engines, with short stacks on small properties, such as the East Hampton and Montauk diesels, but other units may also be affected. Further, it is possible that, during Title V permit renewals for all of the other generating sites, the DEC will require a demonstration that the permitted sources do not cause violations of this standard. This will be determined on a case by case basis when permit modifications or renewals are submitted. The likelihood of this occurring during permit renewals, and the possible compliance cost obligations that may arise are uncertain at this time.

Also in 2010, the EPA finalized standards for the emissions of hazardous air pollutants from Reciprocating Internal Combustion Engines (RICE MACT Rule) that affects the East Hampton and Montauk diesels. This standard will require the installation of oxidation catalysts on the diesels, which will require modification to the Title V air permits. Upon reopening of the permit, the DEC will require that an evaluation of the impact of the diesels on the 1-hr NO2 standard be conducted. If there is a violation of the 1-hr NO2 standard, NYSDEC will not re-issue the permit. To address this, National Grid is currently working with the NYSDEC for approval of modeling protocol that would demonstrate that these units do not cause an exceedance of the standard. LIPA is also evaluating other compliance alternatives that may offer system and/or economic advantages.

The EPA has announced its intention to promulgate a New Source Performance Standard (NSPS) for Greenhouse Gases (GHG) from existing electric generating sources. The EPA has stated that they will take a “common sense” approach, based on cost effective and readily available strategies and that the GHG NSPS will not focus on achieving a single GHG reduction target. A proposed rule for existing generating units is expected in July of this year, at which point the potential impact will be evaluated.

National Grid and the DEC are parties to a 1998 Consent Order for opacity, for which certain fines are assessed for occasionally exceeding power plant stack opacity limits. Improvements in plant infrastructure and plant operating practices have significantly reduced such occurrences and the amount of fines in recent years.

The Clean Water Act (CWA) requires that electric generating stations hold State Pollutant Discharge Elimination System (SPDES) permits, which reflect water quality considerations for the protection of the environment. Additional capital expenditures will be required as a result of the CWA and DEC requirements to provide Best Technology Available (BTA) to protect marine life from possible impacts from the steam electric generators’ cooling water intake systems under Section 316 of the Act. As directed by DEC, National Grid has undertaken studies of the impact of its cooling water intake systems on aquatic resources and submitted engineering alternatives to DEC for mitigating such impacts. National Grid believes that in most cases implementing technologies and procedures to reduce cooling water flow during certain periods should be sufficient to meet the performance standards established by the DEC.

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DEC has issued draft SPDES permits for the Glenwood, Port Jefferson and E.F. Barrett power stations. With respect to Glenwood, the DEC concurred with National Grid that cooling towers are not required and will allow the plant to operate at its projected low capacity factor until 2013 at which time it would need to install fish protection technologies if it were to operate beyond that date. For Port Jefferson, DEC also concurred that cooling towers would not be required but required additional fish protection technologies beyond those proposed by National Grid. In addition, two intervenors have requested that DEC impose cooling tower requirements at Glenwood and Port Jefferson. National Grid, LIPA, DEC, and the intervenors are negotiating an agreement to address the interveners'' concerns with alternate technologies and operational limitations. At present, no capital expenditures would be required at Glenwood unless the plant operates beyond May 2013 at which time approximately $7 million in controls would be required. At Port Jefferson, a suite of technologies at an approximate cost of $16.5 million would be required to be expended within three years of permit issuance.

For E.F. Barrett, DEC proposed cooling towers in the draft permit. National Grid filed comments on various aspects of the draft permit, including the selection of cooling towers as Best Technology Available and the need for an environmental review. DEC subsequently withdrew the draft permit to allow for a full environmental review of the potential impacts of cooling towers under the State Environmental Quality Review Act. DEC has not yet issued draft permits for Northport and Far Rockaway.

The final nature and extent of any fish protection expenditure cannot be fully determined until ongoing analysis of the impacts and mitigation options are completed by DEC, and permit conditions are negotiated, subjected to public comment, and the outcome of potentially litigation. At this time, estimates for compliance upgrades proposed by National Grid for all PSA units, covering a range of potential mitigation options, could be between $80 and $100 million. While detailed cost estimates have not yet been prepared, if cooling towers are required at E.F. Barrett, preliminary estimates indicate that costs would be approximately $120 million. The potential cost for installing cooling towers at all power stations could be on the order of $400 million, with additional maintenance and fuel costs, which may be passed through to the Authority depending on the timing of these requirements and the exercise of certain options that the Authority has under the PSA.

Recent changes to the SPCC regulations (40 CFR 112) effectively require the internal inspections of No. 6 oil tanks on a frequency and in a manner that is based on the criteria of the American Petroleum Institute's guidelines. Over the past ten years, eight tanks were internally inspected and no significant corrosion was found. Over the next 15 years, the remaining ten additional tanks will be scheduled for internal inspections at an estimated cost of $9 million which may be passed through to the Authority depending on the timing of these requirements and the exercise of certain options that the Authority has under the PSA. Any subsequent repairs that may be indicated by these inspections cannot be estimated at this time. The Authority does not believe that its share of these costs will have a material adverse effect on its financial position, cash flows or results of operations.

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Report on Internal Control over Financial Reporting and on Compliance and Other Matters Based on an Audit of Financial Statements Performed in Accordance with *Government Auditing Standards*

The Board of Trustees
Long Island Power Authority:

We have audited the basic financial statements of the Long Island Power Authority (Authority) as of and for the year ended December 31, 2010, and have issued our report thereon dated March 31, 2011. We conducted our audit in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States.

Internal Control over Financial Reporting

In planning and performing our audit, we considered the Authority's internal control over financial reporting as a basis for designing our auditing procedures for the purpose of expressing an opinion on the financial statements, but not for the purpose of expressing an opinion on the effectiveness of the Authority's internal control over financial reporting. Accordingly, we do not express an opinion on the effectiveness of the Authority's internal control over financial reporting.

A deficiency in internal control over financial reporting exists when the design or operation of a control does not allow management or employees, in the normal course of performing their assigned functions, to prevent, or detect and correct misstatements on a timely basis. A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the entity's financial statements will not be prevented, or detected and corrected on a timely basis.

Our consideration of internal control over financial reporting was for the limited purpose described in the first paragraph of this section and was not designed to identify all deficiencies in internal control over financial reporting that might be deficiencies, significant deficiencies, or material weaknesses. We did not identify any deficiencies in internal control over financial reporting that we consider to be material weaknesses, as defined above.

Compliance and Other Matters

As part of obtaining reasonable assurance about whether the Authority's basic financial statements are free of material misstatement, we performed tests of its compliance with certain provisions of laws, regulations, contracts and grant agreements, noncompliance with which could have a direct and material effect on the determination of financial statement amounts. However, providing an opinion on compliance with those provisions was not an objective of our audit and, accordingly, we do not express such an opinion. The results of our tests disclosed no instances of noncompliance or other matters that are required to be reported under *Government Auditing Standards*.

This report is intended solely for the information and use of Authority management, the Authority's Board of Trustees, the New York State Division of the Budget and the New York State Office of the State Comptroller and is not intended to be and should not be used by anyone other than those specified parties.

KPMG LLP

March 31, 2010