AES CORP
Form 10-Q
May 09, 2011

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Quarterly Period Ended March 31, 2011

or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number 1-12291

THE AES CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**54 1163725**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
4300 Wilson Boulevard Arlington, Virginia	**22203**
(Address of principal executive offices)	**(Zip Code)**

(703) 522-1315

Registrant s telephone number, including area code:

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer , accelerated filer , and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x	Accelerated filer ¨	Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

The number of shares outstanding of Registrant s Common Stock, par value $0.01 per share, on May 2, 2011, was 782,008,035.

THE AES CORPORATION

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2011

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PART I: FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

THE AES CORPORATION

Condensed Consolidated Statements of Operations

(Unaudited)

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	(in millions, except per share amounts)	
Revenue:		
Regulated	$ 2,413	$ 2,241
Non-Regulated	1,851	1,679
Total revenue	4,264	3,920
Cost of Sales:		
Regulated	(1,823)	(1,666)
Non-Regulated	(1,425)	(1,293)
Total cost of sales	(3,248)	(2,959)
Gross margin	1,016	961
General and administrative expenses	(95)	(80)
Interest expense	(351)	(381)
Interest income	95	108
Other expense	(17)	(12)
Other income	16	9
Gain on sale of investments	6	-
Foreign currency transaction gains (losses) on net monetary position	33	(51)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES AND EQUITY IN EARNINGS OF AFFILIATES	703	554
Income tax expense	(218)	(186)
Net equity in earnings of affiliates	10	13
INCOME FROM CONTINUING OPERATIONS	495	381
Income (loss) from operations of discontinued businesses, net of income tax (benefit) expense of $(6) and $11, respectively	(12)	34
Loss from disposal of discontinued businesses, net of income tax expense of $0 and $0, respectively	-	(13)
NET INCOME	483	402
Noncontrolling interests:		
Income from continuing operations attributable to noncontrolling interests	(259)	(211)
Income from discontinued operations attributable to noncontrolling interests	-	(4)
Total net income attributable to noncontrolling interests	(259)	(215)
NET INCOME ATTRIBUTABLE TO THE AES CORPORATION	$ 224	$ 187
BASIC EARNINGS PER SHARE:		
Income from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ 0.30	$ 0.24
Discontinued operations attributable to The AES Corporation common stockholders, net of tax	(0.02)	0.03

NET INCOME ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$	0.28	$	0.27
DILUTED EARNINGS PER SHARE:				
Income from continuing operations attributable to The AES Corporation common stockholders, net of tax	$	0.30	$	0.24
Discontinued operations attributable to The AES Corporation common stockholders, net of tax		(0.02)		0.03
NET INCOME ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$	0.28	$	0.27
AMOUNTS ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS:				
Income from continuing operations, net of tax	$	236	$	170
Discontinued operations, net of tax		(12)		17
Net income	$	224	$	187

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THE AES CORPORATION

Condensed Consolidated Balance Sheets

	March 31, 2011	December 31, 2010
	(in millions except share and per share data)	
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 2,008	$ 2,552
Restricted cash	512	502
Short-term investments	1,713	1,730
Accounts receivable, net of allowance for doubtful accounts of $324 and $307, respectively	2,489	2,316
Inventory	634	562
Receivable from affiliates	7	27
Deferred income taxes current	310	306
Prepaid expenses	203	225
Other current assets	741	1,056
Current assets of discontinued and held for sale businesses	129	170
Total current assets	8,746	9,446
NONCURRENT ASSETS		
Property, Plant and Equipment:		
Land	1,147	1,126
Electric generation, distribution assets and other	28,389	28,172
Accumulated depreciation	(9,366)	(9,145)
Construction in progress	4,853	4,459
Property, plant and equipment, net	25,023	24,612
Other Assets:		
Deferred financing costs, net of accumulated amortization of $296 and $287, respectively	371	375
Investments in and advances to affiliates	1,544	1,320
Debt service reserves and other deposits	688	653
Goodwill	1,269	1,271
Other intangible assets, net of accumulated amortization of $163 and $157, respectively	515	511
Deferred income taxes noncurrent	627	646
Other	1,618	1,589
Noncurrent assets of discontinued and held for sale businesses	99	88
Total other assets	6,731	6,453
TOTAL ASSETS	$ 40,500	$ 40,511
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 1,873	$ 2,053
Accrued interest	383	257
Accrued and other liabilities	2,273	2,662
Non-recourse debt current, including $1,169 and $1,152, respectively, related to variable interest entities	2,610	2,567
Recourse debt current	200	463
Current liabilities of discontinued and held for sale businesses	212	63
Total current liabilities	7,551	8,065
LONG-TERM LIABILITIES		
Non-recourse debt noncurrent, including $2,256 and $2,201, respectively, related to variable interest entities	12,492	12,372
Recourse debt noncurrent	4,150	4,149

Deferred income taxes noncurrent	907	895
Pension and other post-retirement liabilities	1,523	1,512
Other long-term liabilities	2,713	2,814
Long-term liabilities of discontinued and held for sale businesses	62	231
Total long-term liabilities	21,847	21,973
Contingencies and Commitments (see Note 9)		
Cumulative preferred stock of subsidiary	60	60
EQUITY		
THE AES CORPORATION STOCKHOLDERS EQUITY		
Common stock ($0.01 par value, 1,200,000,000 shares authorized; 806,431,926 issued and 784,643,934 outstanding at March 31, 2011 and 804,894,313 issued and 787,607,240 outstanding at December 31, 2010)	8	8
Additional paid-in capital	8,460	8,444
Retained earnings	844	620
Accumulated other comprehensive loss	(2,248)	(2,383)
Treasury stock, at cost (21,787,992 shares at March 31, 2011 and 17,287,073 shares at December 31, 2010)	(272)	(216)
Total The AES Corporation stockholders equity	6,792	6,473
NONCONTROLLING INTERESTS	4,250	3,940
Total equity	11,042	10,413
TOTAL LIABILITIES AND EQUITY	$ 40,500	$ 40,511

THE AES CORPORATION

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	Three Months Ended March 31,	
	2011	2010
	(in millions)	
OPERATING ACTIVITIES:		
Net income	$ 483	$ 402
Adjustments to net income:		
Depreciation and amortization	305	293
Loss from sale of investments and impairment expense	3	4
Loss on disposal and impairment write-down discontinued operations	-	13
Provision for deferred taxes	17	29
Contingencies	22	46
Other	(84)	(20)
Changes in operating assets and liabilities:		
Increase in accounts receivable	(112)	(64)
(Increase) decrease in inventory	(69)	3
Decrease in prepaid expenses and other current assets	16	31
(Increase) decrease in other assets	11	(70)
Increase (decrease) in accounts payable and accrued liabilities	(41)	56
Decrease in income taxes receivable and other income taxes payable, net	(105)	(97)
Increase in other liabilities	59	42
Net cash provided by operating activities	505	668
INVESTING ACTIVITIES:		
Capital expenditures	(479)	(493)
Acquisitions net of cash acquired	(138)	(34)
Proceeds from the sale of businesses	8	99
Proceeds from the sale of assets	4	-
Sale of short-term investments	1,241	1,006
Purchase of short-term investments	(1,181)	(1,102)
(Increase) decrease in restricted cash	11	(46)
Increase in debt service reserves and other assets	(7)	(61)
Affiliate advances and equity investments	(40)	(23)
Other investing	(20)	59
Net cash used in investing activities	(601)	(595)
FINANCING ACTIVITIES:		
Issuance of common stock	-	1,570
Borrowings under the revolving credit facilities, net	24	26
Issuance of non-recourse debt	115	216
Repayments of recourse debt	(268)	-
Repayments of non-recourse debt	(201)	(182)
Payments for deferred financing costs	(5)	(13)
Distributions to noncontrolling interests	(43)	(72)
Financed capital expenditures	(17)	(30)
Purchase of treasury stock	(63)	-
Other financing	(5)	-
Net cash (used in) provided by financing activities	(463)	1,515

Effect of exchange rate changes on cash		15		(21)
Total increase (decrease) in cash and cash equivalents		(544)		1,567
Cash and cash equivalents, beginning		2,552		1,780
Cash and cash equivalents, ending	$	2,008	$	3,347
SUPPLEMENTAL DISCLOSURES:				
Cash payments for interest, net of amounts capitalized	$	229	$	284
Cash payments for income taxes, net of refunds	$	304	$	260

See Notes to Condensed Consolidated Financial Statements

THE AES CORPORATION

Condensed Consolidated Statements of Changes in Equity

(Unaudited)

	THE AES CORPORATION STOCKHOLDERS						
	Common Stock	Treasury Stock	Additional Paid-In Capital	Retained Earnings (in millions)	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Consolidated Comprehensive Income
Balance at January 1, 2011	$ 8	$ (216)	$ 8,444	$ 620	$ (2,383)	$ 3,940	
Net income	-	-	-	224	-	259	$ 483
Change in fair value of available-for-sale securities, net of income tax	-	-	-	-	(1)	-	(1)
Foreign currency translation adjustment, net of income tax	-	-	-	-	74	54	128
Change in unfunded pensions obligation, net of income tax	-	-	-	-	1	2	3
Change in derivative fair value, including a reclassification to earnings, net of income tax	-	-	-	-	61	10	71
Other comprehensive income							201
Total comprehensive income							$ 684
Capital contributions from noncontrolling interests	-	-	-	-	-	1	
Distributions to noncontrolling interests	-	-	-	-	-	(16)	
Acquisition of treasury stock	-	(63)	-	-	-	-	
Issuance of common stock under benefit plans and exercise of stock options and warrants, net of income tax	-	7	6	-	-	-	
Stock compensation	-	-	10	-	-	-	
Balance at March 31, 2011	$ 8	$ (272)	$ 8,460	$ 844	$ (2,248)	$ 4,250	

	THE AES CORPORATION STOCKHOLDERS						
	Common Stock	Treasury Stock	Additional Paid-In Capital	Retained Earnings (in millions)	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Consolidated Comprehensive Income
Balance at January 1, 2010	$ 7	$ (126)	$ 6,868	$ 650	$ (2,724)	$ 4,205	
Net income	-	-	-	187	-	215	$ 402
Change in fair value of available-for-sale securities, net of income tax	-	-	-	-	(4)	-	(4)
Foreign currency translation adjustment, net of income tax	-	-	-	-	(88)	(46)	(134)
Change in unfunded pensions obligation, net of income tax	-	-	-	-	1	1	2
Change in derivative fair value, including a reclassification to earnings, net of income tax	-	-	-	-	(28)	(6)	(34)
Other comprehensive income							(170)
Total comprehensive income							$ 232
	-	-	-	(47)	(38)	15	

Cumulative effect of consolidation of entities under variable interest entity accounting guidance											
Cumulative effect of deconsolidation of entities under variable interest entity accounting guidance		-		-		-		1		-		-
Capital contributions from noncontrolling interests		-		-		-		-		-		2
Distributions to noncontrolling interests		-		-		-		-		-		(97)
Issuance of common stock		1		-		1,566		-		-		-
Issuance of common stock under benefit plans and exercise of stock options and warrants, net of income tax		-		8		6		-		-		-
Stock compensation		-		-		7		-		-		-
Balance at March 31, 2010	$	8	$	(118)	$	8,447	$	791	$	(2,881)	$	4,289

See Notes to Condensed Consolidated Financial Statements

THE AES CORPORATION

Notes to Condensed Consolidated Financial Statements

For the Three Months Ended March 31, 2011 and 2010

1. FINANCIAL STATEMENT PRESENTATION

The prior period condensed consolidated financial statements in this Quarterly Report on Form 10-Q (Form 10-Q) have been reclassified to reflect the businesses held for sale and discontinued operations as discussed in Note 14 *Discontinued Operations*.

Consolidation

In this Quarterly Report the terms AES , the Company , us or we refer to the consolidated entity including its subsidiaries and affiliates. The tern The AES Corporation , the Parent or the Parent Company refer only to the publicly-held holding company, The AES Corporation, excluding its subsidiaries and affiliates. Furthermore, variable interest entities (VIEs) in which the Company has an interest have been consolidated where the Company is the primary beneficiary. Investments in which the Company has the ability to exercise significant influence, but not control, are accounted for using the equity method of accounting. All intercompany transactions and balances have been eliminated in consolidation.

AES Thames, LLC (Thames), a 208 MW coal-fired plant in Connecticut, filed petitions for bankruptcy protection under Chapter 11 in the U. S. Bankruptcy Court on February 1, 2011. Effective that date, the Company lost control of the business and is no longer able to exercise significant influence over its operating and financial policies. In accordance with the accounting guidance on consolidations, Thames was deconsolidated in February 2011 and is now accounted for as a cost method investment. Thames had total assets and total liabilities of $158 million and $170 million, respectively, on February 1, 2011. The deconsolidation resulted in a gain of $12 million, which was deferred pending the completion of the bankruptcy proceedings.

Interim Financial Presentation

The accompanying unaudited condensed consolidated financial statements and footnotes have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP) as contained in the Financial Accounting Standards Board (FASB) Accounting Standards Codification (the Codification or ASC) for interim financial information and Article 10 of Regulation S-X issued by the Securities and Exchange Commission (SEC). Accordingly, they do not include all the information and footnotes required by U.S. GAAP for annual fiscal reporting periods. In the opinion of management, the interim financial information includes all adjustments of a normal recurring nature necessary for a fair presentation of the results of operations, financial position, changes in equity and cash flows. The results of operations for the three months ended March 31, 2011 are not necessarily indicative of results that may be expected for the year ending December 31, 2011. The accompanying condensed consolidated financial statements are unaudited and should be read in conjunction with the 2010 audited consolidated financial statements and notes thereto, which are included in the 2010 Form 10-K filed with the SEC on February 25, 2011.

Change in Estimate

In 2011, the Company changed its estimate related to depreciation on property, plant and equipment at its Brazilian concessionary utility and generation businesses. Based on recent information received from regulators, the depreciation rates and salvage values for its concession assets have been adjusted on a prospective basis to reflect a remuneration basis, which equates to the reimbursement expected by the Company at the end of the concession period. For the three months ended March 31, 2011 the impact to the condensed consolidated statement of operations was an increase to depreciation expense of $17 million, or $0.02 per share, and a decrease of $4 million, or $0.01 per share, to net income attributable to The AES Corporation.

New Accounting Policies Adopted

Accounting Standards Update (ASU) No. 2009-13, Revenue Recognition (Topic 605), Multiple-Deliverable Revenue Arrangements

In October 2009, the Financial Accounting Standards Board (FASB) issued ASU No. 2009-13, which amended the accounting guidance related to revenue recognition. The amended guidance provides primarily for two changes to the prior guidance for multiple-element revenue arrangements. The first eliminated the requirement that there be objective and reliable evidence of fair value for any undelivered items in order for a delivered item to be treated as a separate unit of accounting. The second required that the consideration from multiple-element revenue arrangements be allocated to all the deliverables based on their relative selling price at the inception of the arrangement. The amended guidance must have been adopted by all entities no later than fiscal years beginning on or after June 15, 2010, or January 1, 2011 for AES. As AES did not elect the early adoption that was permitted for the amended guidance, AES adopted it on January 1, 2011. AES elected prospective adoption and applied the revised guidance to all revenue arrangements entered into or materially modified after the date of adoption. As a result, the adoption of ASU No. 2009-13 did not have a material impact on the financial position and results of operations of AES and ASU No. 2009-13 is not expected to have material impact in future periods.

ASU No. 2010-28, Intangibles Goodwill and Other (Topic 350), When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts

In December 2010, the FASB issued ASU No. 2010-28, which amends the accounting guidance related to goodwill. The amendments in ASU No. 2010-28 modify Step One of the goodwill impairment test for reporting units with zero or negative carrying amounts. For those reporting units, an entity is required to perform Step Two of the goodwill impairment test if it is more likely than not that a goodwill impairment exists, eliminating an entity s ability to assert that a reporting unit is not required to perform Step Two because the carrying amount of the reporting unit is zero or negative despite the existence of qualitative factors that indicate the goodwill is more likely than not impaired. In determining whether it is more likely than not that a goodwill impairment exists, an entity should consider whether there are any adverse qualitative factors indicating that an impairment may exist. The Company adopted ASU No. 2010-28 on January 1, 2011. The adoption did not have any impact on the Company as none of its reporting units has a zero or negative carrying amount.

Accounting Pronouncements Issued But Not Yet Effective

The following accounting standards update has been issued, but as of March 31, 2011 is not yet effective for and has not been adopted by AES.

ASU No. 2011-2, A Creditor s Determination of Whether a Restructuring Is a Troubled Debt Restructuring

In April 2011, the Financial Accounting Standards Board (FASB) issued ASU No. 2011-2, which provides additional guidance and clarification to help creditors determine whether a creditor has granted a concession and whether a debtor is experiencing financial difficulties for purposes of determining whether a restructuring constitutes a troubled debt restructuring. ASU 2011-2 is effective for the first interim or annual period beginning on or after June 15, 2011, or the three months ended September 30, 2011 for AES. The adoption is not expected to have a material impact on the Company s financial position, results of operations or cash flows.

2. INVENTORY

The following table summarizes the Company s inventory balances as of March 31, 2011 and December 31, 2010:

	March 31, 2011	December 31, 2010
	(in millions)	
Coal, fuel oil and other raw materials	$ 341	$ 276
Spare parts and supplies	293	286
Total	$ 634	$ 562

3. FAIR VALUE DISCLOSURES

The fair value of current financial assets and liabilities, debt service reserves and other deposits approximate their reported carrying amounts. The fair value of non-recourse debt is estimated based upon the type of loan. For variable rate loans, carrying value approximates fair value. For fixed rate loans, the fair value is estimated using quoted market prices or discounted cash flow analyses. See Note 8 *Debt* for additional information on the fair value and carrying value of debt. The fair value of interest rate swap, cap and floor agreements, foreign currency forwards, swaps and options and energy derivatives is the estimated net amount that the Company would receive or pay to sell or transfer the agreements as of the balance sheet date.

The estimated fair values of the Company s assets and liabilities have been determined using available market information. By virtue of these amounts being estimates and based on hypothetical transactions to sell assets or transfer liabilities, the use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts.

The following table summarizes the carrying amount and fair value of certain of the Company s financial assets and liabilities as of March 31, 2011 and December 31, 2010:

	March 31, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Assets				
Marketable securities	$ 1,753	$ 1,753	$ 1,772	$ 1,772
Derivatives	139	139	124	124
Total assets	$ 1,892	$ 1,892	$ 1,896	$ 1,896
Liabilities				
Debt	$ 19,452	$ 20,087	$ 19,551	$ 20,137
Derivatives	358	358	423	423
Total liabilities	$ 19,810	$ 20,445	$ 19,974	$ 20,560

Valuation Techniques:

The fair value measurement accounting guidance describes three main approaches to measuring the fair value of assets and liabilities: (1) market approach; (2) income approach and (3) cost approach. The market approach uses prices and other relevant information generated from market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to convert future amounts to a single present value amount. The measurement is based on current market expectations of the return on those

future amounts. The cost approach is based on the amount that would currently be required to replace an asset. The Company measures its investments and derivatives at fair value on a recurring basis. Additionally, in connection with annual or event-driven impairment evaluations, certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis. These include long-lived tangible assets (i.e., property, plant and equipment), goodwill and intangible assets (e.g., sales concessions, land use rights and emissions allowances etc). In general, the Company determines the fair value of investments and derivatives using the market approach and the income approach, respectively. In the nonrecurring measurements of nonfinancial assets and liabilities, all three approaches are considered; however, fair value generated by the income approach is often selected.

Investments

The Company s investments measured at fair value generally consist of marketable debt and equity securities. Equity securities are measured at fair value using quoted market prices. Debt securities primarily consist of unsecured debentures, certificates of deposit and government debt securities held by our Brazilian subsidiaries. Returns and pricing on these instruments are generally indexed to the CDI (Brazilian equivalent to London Inter Bank Offered Rate (LIBOR), a benchmark interest rate widely used by banks in the money market) or Selic (overnight borrowing rate) rates in Brazil and are adjusted based on the banks assessment of the specific businesses. Fair value is determined from comparisons to market data obtained for similar assets and are considered Level 2 in the fair value hierarchy. For more detail regarding the fair value of investments see Note 4 *Investments in Marketable Securities*.

Derivatives

When deemed appropriate, the Company manages its risk from interest and foreign currency exchange rate and commodity price fluctuations through the use of financial and physical derivative instruments. The Company s derivatives are primarily interest rate swaps to hedge non-recourse debt to establish a fixed rate on variable rate debt, foreign exchange instruments to hedge against currency fluctuations, commodity derivatives to hedge against commodity price fluctuations and embedded derivatives associated with commodity contracts. The Company s subsidiaries are counterparties to various over-the-counter derivatives, which include interest rate swaps and options, foreign currency options and forwards and commodity swaps. In addition, the Company s subsidiaries are counterparties to certain power purchase agreements (PPAs) and fuel supply agreements that are derivatives or include embedded derivatives.

For the derivatives where there is a standard industry valuation model, the Company uses that model to estimate the fair value. For the derivatives (such PPAs and fuel supply agreements that are derivatives or include embedded derivatives) where there is not a standard industry valuation model, the Company has created internal valuation models to estimate the fair value, using observable data to the extent available. For all derivatives, the income approach is used, which consists of forecasting future cash flows based on contractual notional amounts and applicable and available market data as of the valuation date. The following are among the most common market data inputs used in the income approach: volatilities, spot and forward benchmark interest rates (such as LIBOR and Euro Inter Bank Offered Rate (EURIBOR)), foreign exchange rates and commodity prices. Forward rates and prices are generally obtained from published information provided by pricing services for an instrument with the same duration as the derivative instrument being valued. In situations where significant inputs are not observable, the Company uses relevant techniques to best estimate the inputs, such as regression analysis, Monte Carlo simulation or prices for similarly traded instruments available in the market.

For each derivative, the income approach is used to estimate the cash flows over the remaining term of the contract. Those cash flows are then discounted using the relevant spot benchmark interest rate (such as LIBOR or EURIBOR) plus a spread that reflects the credit or nonperformance risk. This risk is estimated by the Company using credit spreads and risk premiums that are observable in the market, whenever possible, or estimated borrowing costs based on bank quotes, industry publications and/or information on financing closed on similar projects. To the extent that management can estimate the fair value of these assets or liabilities without the use of significant unobservable inputs, these derivatives are classified as Level 2.

In certain instances, the published forward rates or prices may not extend through the remaining term of the contract and management must make assumptions to extrapolate the curve, which necessitates the use of unobservable inputs, such as proxy commodity prices or historical settlements to forecast forward prices. In addition, in certain instances, there may not be third party data readily available which requires the use of unobservable inputs. Similarly, in certain instances, the spread that reflects the credit or nonperformance risk is unobservable. The fair value hierarchy of an asset or a liability is based on the level of significance of the input assumptions. An input assumption is considered significant if it affects the fair value by at least 10%. Assets and liabilities are transferred to Level 3 when the use of unobservable inputs becomes significant. Similarly, when the use of unobservable input becomes insignificant for Level 3 assets and liabilities, they are transferred to Level 2.

Transfers in and out of Level 3 are determined as of the end of the reporting period and are from and to Level 2. The Company has not had any Level 1 derivatives so there have not been any transfers between Levels 1 and 2.

Nonfinancial Assets and Liabilities

For nonrecurring measurements derived using the income approach, fair value is determined using valuation models based on the principles of discounted cash flows (DCF). The income approach is most often used in the impairment evaluation of long-lived tangible assets, goodwill and intangible assets. The Company has developed internal valuation models for such valuations; however, an independent valuation firm may be engaged in certain situations. In such situations, the independent valuation firm largely uses DCF valuation models as the primary measure of fair value though other valuation approaches are also considered. A few examples of input assumptions to such valuations include macroeconomic factors such as growth rates, industry demand, inflation, exchange rates and power and commodity prices. Whenever possible, the Company attempts to obtain market observable data to develop input assumptions. Where the use of market observable data is limited or not possible for certain input assumptions, the Company develops its own estimates using a variety of techniques such as regression analysis and extrapolations.

For nonrecurring measurements derived using the market approach, recent market transactions involving the sale of identical or similar assets are considered. The use of this approach is limited because it is often difficult to find sale transactions of identical or similar assets. This approach is used in the impairment evaluations of certain intangible assets. Otherwise, it is used to corroborate the fair value determined under the income approach.

For nonrecurring measurements derived using the cost approach, fair value is typically determined using the replacement cost approach. Under this approach, the depreciated replacement cost of assets is determined by first determining the current replacement cost of assets and then applying the remaining useful life percentages to such cost. Further adjustments for economic and functional obsolescence are made to the depreciated replacement cost. This approach involves a considerable amount of judgment which is why its use is limited to the measurement of a few long-lived tangible assets. Like the market approach, this approach is also used to corroborate the fair value determined under the income approach. For the three months ended March 31, 2011, the Company did not measure any nonfinancial assets under the cost approach.

Fair Value Considerations:

In determining fair value, the Company considers the source of observable market data inputs, liquidity of the instrument, the credit risk of the counterparty and the risk of the Company s or its counterparty s nonperformance. The conditions and criteria used to assess these factors are:

Sources of market assumptions

The Company derives most of its market assumptions from market efficient data sources (e.g., Bloomberg and Platt s). In some cases, where market data is not readily available, management uses comparable market sources and empirical evidence to derive market assumptions to determine the fair value.

Market liquidity

The Company evaluates market liquidity based on whether the financial or physical instrument, or the underlying asset, is traded in an active or inactive market. An active market exists if the prices are fully transparent to market participants, can be measured by market bid and ask quotes, the market has a relatively large proportion of trading volume as compared to the Company s current trading volume and the market has a significant number of market participants that will allow the market to rapidly absorb the quantity of the assets traded without significantly affecting the market price. Another factor the Company considers when determining whether a market is active or inactive is the presence of government or regulatory controls over pricing that could make it difficult to establish a market based price when entering into a transaction.

Nonperformance risk

Nonperformance risk refers to the risk that the obligation will not be fulfilled and affects the value at which a liability is transferred or an asset is sold. Nonperformance risk includes, but may not be limited to, the Company or counterparty s credit and settlement risk. Nonperformance risk adjustments are dependent on credit spreads, letters of credit, collateral, other arrangements available and the nature of master netting arrangements. The Company and its subsidiaries are parties to various interest rate swaps and options; foreign currency options and forwards; and derivatives and embedded derivatives which subject the Company to nonperformance risk. The financial and physical instruments held at the subsidiary level are generally non-recourse to the Parent Company.

Nonperformance risk on the investments held by the Company is incorporated in the investment s exit price that is derived from quoted market data that is used to mark the investment to fair value.

The Company adjusts for nonperformance or credit risk on its derivative instruments by deducting a credit valuation adjustment (CVA). The CVA is based on the margin or debt spread of the Company s subsidiary or counterparty and the tenor of the respective derivative instrument. The counterparty for a derivative asset position is considered to be the bank or government sponsored banking entity or counterparty to the PPA or commodity contract. The CVA for asset positions is based on the counterparty s credit ratings and debt spreads or, in the absence of readily obtainable credit information, the respective country debt spreads are used as a proxy. The CVA for liability positions is based on the Parent Company s or the subsidiary s current debt spread, the margin on indicative financing arrangements, or in the absence of readily obtainable credit information, the respective country debt spreads are used as a proxy. All derivative instruments are analyzed individually and are subject to unique risk exposures.

Recurring Measurements

The following table sets forth, by level within the fair value hierarchy, the Company s financial assets and liabilities that were measured at fair value on a recurring basis as of March 31, 2011 and December 31, 2010. Financial assets and liabilities have been classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the determination of the fair value of the assets and liabilities and their placement within the fair value hierarchy levels.

	Quoted Market Prices in Active Market for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total March 31, 2011
	(in millions)			
Assets				
Available-for-sale securities	$ 3	$ 1,698	$ 40	$ 1,741
Trading securities	12	-	-	12
Derivatives	-	74	65	139
Total assets	$ 15	$ 1,772	$ 105	$ 1,892
Liabilities				
Derivatives	$ -	$ 338	$ 20	$ 358
Total liabilities	$ -	$ 338	$ 20	$ 358

	Quoted Market Prices in Active Market for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total December 31, 2010
	(in millions)			
Assets				
Available-for-sale securities	$ 8	$ 1,712	$ 42	$ 1,762
Trading securities	10	-	-	10
Derivatives	-	63	61	124
Total assets	$ 18	$ 1,775	$ 103	$ 1,896
Liabilities				
Derivatives	$ -	$ 411	$ 12	$ 423
Total liabilities	$ -	$ 411	$ 12	$ 423

The following table presents a reconciliation of derivative assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the three months ended March 31, 2011 and 2010 (by type of derivative):

	Three Months Ended March 31, 2011				
	Interest Rate	Cross Currency	Foreign Currency (in millions)	Commodity and Other	Total
Balance at January 1[1]	$ (1)	$ 10	$ 22	$ 18	$ 49
Total gains (losses) (realized and unrealized):					
Included in earnings[2]	-	2	1	8	11
Included in other comprehensive income	(4)	(8)	-	-	(12)
Included in regulatory assets	-	-	-	(1)	(1)
Settlements	-	1	1	-	2
Transfers of assets (liabilities) into Level 3[3]	(2)	-	(1)	(1)	(4)
Balance at March 31[1]	$ (7)	$ 5	$ 23	$ 24	$ 45
Total gains/(losses) for the period included in earnings attributable to the change in unrealized gains/(losses) relating to assets and liabilities held at the end of the period	$ -	$ 2	$ -	$ 8	$ 10

	Three Months Ended March 31, 2010				
	Interest Rate	Cross Currency	Foreign Currency (in millions)	Commodity and Other	Total
Balance at January 1[1]	$ (12)	$ (12)	$ -	$ 24	$ -
Total gains (losses) (realized and unrealized):					
Included in earnings[2]	-	6	-	3	9
Included in other comprehensive income	(3)	(2)	-	-	(5)
Included in regulatory assets	(1)	-	-	-	(1)
Settlements	1	1	-	(8)	(6)
Transfers of assets (liabilities) into Level 3[3]	(4)	-	(1)	-	(5)
Transfers of (assets) liabilities out of Level 3[3]	1	-	-	-	1
Balance at March 31[1]	$ (18)	$ (7)	$ (1)	$ 19	$ (7)
Total gains/(losses) for the period included in earnings attributable to the change in unrealized gains/(losses) relating to assets and liabilities held at the end of the period	$ -	$ 6	$ 1	$ (5)	$ 2

(1) Derivative assets and (liabilities) are presented on a net basis.

(2) The gains (losses) included in earnings for these Level 3 derivatives are classified as follows: interest rate and cross currency derivatives as interest expense, foreign currency derivatives as foreign currency transaction gains (losses) and commodity and other derivatives as either non-regulated revenue, non-regulated cost of sales, or other expense. See Note 5 *Derivative Instruments and Hedging Activities* for further information regarding the classification of gains and losses included in earnings in the condensed consolidated statements of operations.

(3) Transfers in and out of Level 3 are determined as of the end of the reporting period and are from and to Level 2, as the Company has no Level 1 derivative assets or liabilities. The (assets) liabilities transferred out of Level 3 are primarily the result of a decrease in the significance of unobservable inputs used to calculate the credit valuation adjustments of these derivative instruments. Similarly, the assets (liabilities) transferred into Level 3 are primarily the result of an increase in the significance of unobservable inputs used to calculate the credit valuation adjustments of these derivative instruments.

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The following table presents a reconciliation of available-for-sale securities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the three months ended March 31, 2011 and 2010:

	Three Months Ended March 31,	
	2011	2010
	(in millions)	
Balance at January 1[1]	$ 42	$ 42
Settlements	(2)	-
Balance at March 31[1]	$ 40	$ 42
Total gains/(losses) for the period included in earnings attributable to the change in unrealized gains/losses relating to assets held at the end of the period	$ -	$ -

[1] Available-for-sale securities in Level 3 are auction rate securities and variable rate demand notes which have failed remarketing or are not actively trading and for which there are no longer adequate observable inputs available to measure the fair value.

4. INVESTMENTS IN MARKETABLE SECURITIES

The following table sets forth the Company s investments in marketable debt and equity securities reported at fair value as of March 31, 2011 and December 31, 2010 by type of investment and by level within the fair value hierarchy. The security types are determined based on the nature and risk of the security and are consistent with how the Company manages, monitors and measures its marketable securities.

	March 31, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
				(in millions)				
AVAILABLE-FOR-SALE:[1]								
Debt securities:								
Unsecured debentures[2]	$ -	$ 742	$ -	$ 742	$ -	$ 727	$ -	$ 727
Certificates of deposit[2]	-	849	-	849	-	877	-	877
Government debt securities	-	43	-	43	-	47	-	47
Other debt securities	-	-	40	40	-	-	42	42
Subtotal	-	1,634	40	1,674	-	1,651	42	1,693
Equity securities:								
Mutual funds	1	64	-	65	1	61	-	62
Common stock	2	-	-	2	7	-	-	7
Subtotal	3	64	-	67	8	61	-	69
Total available-for-sale	3	1,698	40	1,741	8	1,712	42	1,762
TRADING:								
Equity securities:								
Mutual funds	12	-	-	12	10	-	-	10
Total trading	12	-	-	12	10	-	-	10
TOTAL	$ 15	$ 1,698	$ 40	$ 1,753	$ 18	$ 1,712	$ 42	$ 1,772

(1) Amortized cost approximated fair value at March 31, 2011 and December 31, 2010, with the exception of a common stock investment with a cost basis and fair value of $4 million and $2 million, respectively, at March 31, 2011, and a cost basis and fair value of $6 million and $7 million, respectively, at December 31, 2010.

(2) Unsecured debentures are instruments similar to certificates of deposit that are held primarily by our subsidiaries in Brazil. The unsecured debentures and certificates of deposit included here do not qualify as cash equivalents, but meet the definition of a security under the relevant guidance and are therefore classified as available-for-sale securities.

As of March 31, 2011, all available-for-sale debt securities had stated maturities of less than one year, with the exception of variable rate demand notes of $40 million held by IPL. These notes, included in other debt securities in the table above, had a stated maturity of greater than ten years as of March 31, 2011.

The following table summarizes the pre-tax gains and losses related to available-for-sale and trading securities for the three months ended March 31, 2011 and 2010. Gains and losses on the sale of investments are determined using the specific identification method. For the three months ended March 31, 2011 and 2010, there were no realized losses on sales of available-for-sale securities and no other-than-temporary impairment of marketable securities recognized in earnings or other comprehensive income.

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	(in millions)	
Gains included in earnings that relate to trading securities held at the reporting date	$ 1	$ -
Unrealized gains (losses) on available-for-sale securities included in other comprehensive income	$ (2)	$ (6)
Proceeds from sales of available-for-sale securities	$ 1,257	$ 962
Gross realized gains on sales of available-for-sale securities	$ 1	$ -

5. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Risk Management Objectives

The Company is exposed to market risks associated with its enterprise-wide business activities, namely the purchase and sale of fuel and electricity as well as foreign currency risk and interest rate risk. In order to manage the market risks associated with these business activities, we enter into contracts that incorporate derivatives and financial instruments, including forwards, futures, options, swaps or combinations thereof, as appropriate. The Company generally applies hedge accounting to contracts as long as they are eligible under the accounting standards for derivatives and hedging. While derivative transactions are not entered into for trading purposes, some contracts are not eligible for hedge accounting.

Interest Rate Risk

AES and its subsidiaries utilize variable rate debt financing for construction projects and operations, resulting in an exposure to interest rate risk. Interest rate swap, cap and floor agreements are entered into to manage interest rate risk by effectively fixing or limiting the interest rate exposure on the underlying financing. These interest rate contracts range in maturity through 2030, and are typically designated as cash flow hedges. The following table sets forth, by underlying type of interest rate index, the Company s current and maximum outstanding notional under its interest rate derivative instruments, the weighted average remaining term and the percentage of variable-rate debt hedged that is based on the related index as of March 31, 2011 regardless of whether the derivative instruments are in qualifying cash flow hedging relationships:

	March 31, 2011					
	Current		Maximum[1]			
Interest Rate Derivatives	Derivative Notional	Derivative Notional Translated to USD	Derivative Notional	Derivative Notional Translated to USD	Weighted Average Remaining Term[1]	% of Debt Currently Hedged by Index[2]
	(in millions)				(in years)	
LIBOR (U.S. Dollar)	2,586	$ 2,586	2,719	$ 2,719	10	70%
EURIBOR (Euro)	1,096	1,552	1,096	1,552	13	65%
LIBOR (British Pound Sterling)	44	71	61	97	13	69%
Securities Industry and Financial Markets Association Municipal Swap Index (U.S. Dollar)	40	40	40	40	12	N/A[3]

(1) The Company s interest rate derivative instruments primarily include accreting and amortizing notionals. The maximum derivative notional represents the largest notional at any point between March 31, 2011 and the maturity of the derivative instrument, which includes forward starting derivative instruments. The weighted average remaining term represents the remaining tenor of our interest rate derivatives weighted by the corresponding maximum notional.

(2) Excludes variable-rate debt tied to other indices where the Company has no interest rate derivatives.

(3) The debt that was being hedged is no longer exposed to variable interest payments because it is now held on IPL s behalf and no longer bears interest.

Cross currency swaps are utilized in certain instances to manage the risk related to fluctuations in both interest rates and certain foreign currencies. These cross currency contracts range in maturity through 2028. The following table sets forth, by type of foreign currency denomination, the Company s outstanding notional of amounts under its cross currency derivative instruments as of March 31, 2011, which are all in qualifying cash flow hedge relationships. These swaps are amortizing and therefore the notional amount represents the maximum outstanding notional as of March 31, 2011:

	March 31, 2011			
Cross Currency Swaps	**Notional**	**Notional Translated to USD (in millions)**	**Weighted Average Remaining Term[1] (in years)**	**% of Debt Currently Hedged by Index[2]**
Chilean Unidad de Fomento (CLF)	6	$ 253	15	83%

(1) Represents the remaining tenor of our cross currency swaps weighted by the corresponding notional.

(2) Represents the proportion of foreign currency denominated debt hedged by the same foreign currency denominated notional of the cross currency swap.

Foreign Currency Risk

We are exposed to foreign currency risk as a result of our investments in foreign subsidiaries and affiliates. AES operates businesses in many foreign environments and such operations in foreign countries may be impacted by significant fluctuations in foreign currency exchange rates. Foreign currency options and forwards are utilized, where deemed appropriate, to manage the risk related to fluctuations in certain foreign currencies. These foreign currency contracts range in maturity through 2012. The following tables set forth, by type of foreign currency denomination, the Company s outstanding notional amounts over the remaining terms of its foreign currency derivative instruments as of March 31, 2011 regardless of whether the derivative instruments are in qualifying hedging relationships:

	March 31, 2011			
Foreign Currency Options	**Notional**	**Notional Translated to USD[1] (in millions)**	**Probability Adjusted Notional[2]**	**Weighted Average Remaining Term[3] (in years)**
Brazilian Real (BRL)	201	$ 118	$ 26	<1
Euro (EUR)	16	23	12	<1
Argentine Peso (ARS)	28	7	3	<1
Philippine Peso (PHP)	129	3	-	<1
British Pound (GBP)	1	2	1	<1

(1) Represents contractual notionals at inception of trade.

(2) Represents the gross notional amounts times the probability of exercising the option, which is based on the relationship of changes in the option value with respect to changes in the price of the underlying currency.

(3) Represents the remaining tenor of our foreign currency options weighted by the corresponding notional.

Foreign Currency Forwards	Notional	March 31, 2011 Notional Translated to USD	Weighted Average Remaining Term(1)
		(in millions)	(in years)
Chilean Peso (CLP)	99,499	$ 203	<1
British Pound (GBP)	19	31	1
Colombian Peso (COP)	36,564	19	1
Argentine Peso (ARS)	29	6	<1

(1) Represents the remaining tenor of our foreign currency forwards weighted by the corresponding notional.

In addition, certain of our subsidiaries have entered into contracts which contain embedded derivatives that require separate valuation and accounting due to the fact that the item being purchased or sold is denominated in a currency other than the functional currency of that subsidiary or the currency of the item. These contracts range in maturity through 2025. The following table sets forth, by type of foreign currency denomination, the Company s outstanding notional over the remaining terms of its foreign currency embedded derivative instruments as of March 31, 2011:

Embedded Foreign Currency Derivatives	Notional	March 31, 2011 Notional Translated to USD	Weighted Average Remaining Term(1)
		(in millions)	(in years)
Philippine Peso (PHP)	19,801	$ 457	3
Kazakhstani Tenge (KZT)	31,882	219	9
Hungarian Forint (HUF)	19,699	105	1
Argentine Peso (ARS)	315	78	9
Euro (EUR)	21	29	2
Brazilian Real (BRL)	13	8	1
Cameroon Franc (XAF)	775	2	2

(1) Represents the remaining tenor of our foreign currency embedded derivatives weighted by the corresponding notional.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the price of electricity, fuel and environmental credits. Although we primarily consist of businesses with long-term contracts or retail sales concessions (which provide our distribution businesses with a franchise to serve a specific geographic region), a portion of our current and expected future revenues are derived from businesses without significant long-term purchase or sales contracts. These businesses subject our results of operations to the volatility of prices for electricity, fuel and environmental credits in competitive markets. We have used a hedging strategy, where appropriate, to hedge our financial performance against the effects of fluctuations in energy commodity prices. The implementation of this strategy can involve the use of commodity forward contracts, futures, swaps and options. Some of our businesses hedge certain aspects of their commodity risks using financial hedging instruments, as described below.

We also enter into short-term contracts for electricity and fuel in other competitive markets in which we operate. When hedging the output of our generation assets, we have PPAs or other hedging instruments that lock in the spread in dollars per MWh between the cost of fuel to generate a unit of electricity and the price at which the electricity can be sold (Dark Spread where the fuel is coal). The portion of our sales and fuel purchases that are not subject to such agreements will be exposed to commodity price risk.

The PPAs and fuel supply agreements entered into by the Company are evaluated to determine if they meet the definition of a derivative or contain embedded derivatives, either of which require separate valuation and accounting. To be a derivative under the accounting standards for derivatives and hedging, an agreement would need to have a notional and an underlying, require little or no initial net investment and could be net settled. Generally, these agreements do not meet the definition of a derivative, often due to the inability to be net settled. On a quarterly basis, we evaluate the markets for the commodities to be delivered under these agreements to determine if facts and circumstances have changed such that the agreements could then be net settled and meet the definition of a derivative.

Nonetheless, certain of the PPAs and fuel supply agreements entered into by certain of the Company s subsidiaries are derivatives or contain embedded derivatives requiring separate valuation and accounting. These contracts range in maturity through 2024. The following table sets forth by type of commodity, the Company s outstanding notionals for the remaining term of its commodity derivatives and embedded derivative instruments as of March 31, 2011:

	March 31, 2011	
Commodity Derivatives	**Notional (in millions)**	**Weighted Average Remaining Term[1] (in years)**
Natural gas (MMBtu)	36	11
Petcoke (Metric tons)	14	13
Aluminum (MWh)	17[2]	9

(1) Represents the remaining tenor of our commodity and embedded derivatives weighted by the corresponding volume.

(2) Our exposure is to fluctuations in the price of aluminum while the notional is based on the amount of power we sell under the PPA.

In addition, as part of a settlement agreement terminating the gas transportation contracts with Gasoducto GasAndes (Chile) S.A, we have an embedded derivative related to the dividends that could result from our 13% ownership in this gas transportation company.

Accounting and Reporting

The following table sets forth the Company s derivative instruments as of March 31, 2011 and December 31, 2010 by type of derivative and by level within the fair value hierarchy. Derivative assets and liabilities are recognized at their fair value. Derivative assets and liabilities are combined with other balances and included in the following captions in our condensed consolidated balance sheets: current derivative assets in other current assets, noncurrent derivative assets in other noncurrent assets, current derivative liabilities in accrued and other liabilities (except for one in non-recourse debt-current) and long-term derivative liabilities in other long-term liabilities.

	March 31, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
		(in millions)				(in millions)		
Assets								
Current assets:								
Foreign currency derivatives	$ -	$ 7	$ 3	$ 10	$ -	$ 4	$ 3	$ 7
Commodity and other derivatives	-	4	3	7	-	2	3	5
Total current assets	-	11	6	17	-	6	6	12
Noncurrent assets:								
Interest rate derivatives	-	54	-	54	-	49	-	49
Foreign currency derivatives	-	3	26	29	-	4	27	31
Cross currency derivatives	-	-	11	11	-	-	12	12
Commodity and other derivatives	-	6	22	28	-	4	16	20
Total noncurrent assets	-	63	59	122	-	57	55	112
Total assets	$ -	$ 74	$ 65	$ 139	$ -	$ 63	$ 61	$ 124
Liabilities								
Current liabilities:								
Interest rate derivatives	$ -	$ 114	$ 5	$ 119	$ -	$ 137	$ -	$ 137
Cross currency derivatives	-	-	6	6	-	-	2	2
Foreign currency derivatives	-	5	-	5	-	13	-	13
Commodity and other derivatives	-	4	-	4	-	-	-	-
Total current liabilities	-	123	11	134	-	150	2	152
Long-term liabilities:								
Interest rate derivatives	-	201	2	203	-	246	1	247
Foreign currency derivatives	-	13	6	19	-	15	8	23
Commodity and other derivatives	-	1	1	2	-	-	1	1
Total long-term liabilities	-	215	9	224	-	261	10	271
Total liabilities	$ -	$ 338	$ 20	$ 358	$ -	$ 411	$ 12	$ 423

The following table sets forth the fair value and balance sheet classification of derivative instruments as of March 31, 2011 and December 31, 2010:

	March 31, 2011			December 31, 2010		
	Designated as Hedging Instruments	Not Designated as Hedging Instruments (in millions)	Total	Designated as Hedging Instruments	Not Designated as Hedging Instruments (in millions)	Total
Assets						
Current assets:						
Foreign currency derivatives	$ -	$ 10	$ 10	$ -	$ 7	$ 7
Commodity and other derivatives	-	7	7	-	5	5
Total current assets	-	17	17	-	12	12
Noncurrent assets:						
Interest rate derivatives	54	-	54	49	-	49
Foreign currency derivatives	-	29	29	-	31	31
Cross currency derivatives	11	-	11	12	-	12
Commodity and other derivatives	-	28	28	-	20	20
Total noncurrent assets	65	57	122	61	51	112
Total assets	$ 65	$ 74	$ 139	$ 61	$ 63	$ 124
Liabilities						
Current liabilities:						
Interest rate derivatives	$ 112	$ 7	$ 119	$ 126	$ 11	$ 137
Cross currency derivatives	6	-	6	2	-	2
Foreign currency derivatives	2	3	5	8	5	13
Commodity and other derivatives	-	4	4	-	-	-
Total current liabilities	120	14	134	136	16	152
Long-term liabilities:						
Interest rate derivatives	189	14	203	232	15	247
Foreign currency derivatives	-	19	19	-	23	23
Commodity and other derivatives	-	2	2	-	1	1
Total long-term liabilities	189	35	224	232	39	271
Total liabilities	$ 309	$ 49	$ 358	$ 368	$ 55	$ 423

The Company has elected not to offset net derivative positions in the financial statements. Accordingly, the Company does not offset such derivative positions against the fair value of amounts (or amounts that approximate fair value) recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) under master netting arrangements. At March 31, 2011 and December 31, 2010, we held no cash collateral that we received from counterparties to our derivative positions. As we have not received collateral, our derivative assets are exposed to the credit risk of the respective counterparty and, due to this credit risk, the fair value of our derivative assets (as shown in the above two tables) have been reduced by a credit valuation adjustment. Also, at March 31, 2011 and December 31, 2010, we had no cash collateral posted with (held by) counterparties to our derivative positions.

The table below sets forth the pre-tax accumulated other comprehensive income (loss) expected to be recognized as an increase (decrease) to income from continuing operations before income taxes over the next twelve months as of March 31, 2011 for the following types of derivatives:

	Accumulated Other Comprehensive Income (Loss) (in millions)
Interest rate derivatives	$ (74)
Cross currency derivatives	$ (4)
Foreign currency derivatives	$ (2)

The balance in accumulated other comprehensive loss related to derivative transactions will be reclassified into earnings as interest expense is recognized for interest rate hedges and cross currency swaps, as depreciation is recognized for interest rate hedges during construction, and as foreign currency gains and losses are recognized for hedges of foreign currency exposure. These balances are included in the condensed consolidated statements of cash flows as operating and/or investing activities based on the nature of the underlying transaction.

The following tables set forth the gains (losses) recognized in accumulated other comprehensive loss (AOCL) and earnings related to the effective portion of derivative instruments in qualifying cash flow hedging relationships, as defined in the accounting standards for derivatives and hedging, for the three months ended March 31, 2011 and 2010:

	Gains (Losses) Recognized in AOCL Three Months Ended March 31,		Classification in Condensed Consolidated	Gains (Losses) Reclassified from AOCL into Earnings(1) Three Months Ended March 31,	
	2011	2010	Statement of Operations	2011	2010
	(in millions)			(in millions)	
Interest rate derivatives	$ 52	$ (82)	Interest expense	$ (26)(2)	$ (28)(2)
			Non-regulated cost of sales	(1)	-
			Net equity in earnings of affiliates	(1)	(1)
Cross currency derivatives	(8)	(3)	Interest expense	(5)	(1)
Foreign currency derivatives	5	-	Foreign currency transaction gains (losses)	(2)	-
Commodity derivatives electricity	1	12	Non-regulated revenue	-	-
Total	$ 50	$ (73)		$ (35)	$ (30)

(1) Excludes $0 million and $(2) million related to discontinued operations for the three months ended March 31, 2011 and 2010, respectively.

(2) Includes amounts that were reclassified from AOCL related to derivative instruments that previously, but no longer, qualify for cash flow hedge accounting.

The following table sets forth the pre-tax gains (losses) recognized in earnings related to the ineffective portion of derivative instruments in qualifying cash flow hedging relationships, as defined in the accounting standards for derivatives and hedging, for the three months ended March 31, 2011 and 2010:

	Classification in Condensed Consolidated Statement of Operations	Gains (Losses) Recognized in Earnings Three Months Ended March 31, 2011	2010
		(in millions)	
Interest rate derivatives	Interest expense	$ (7)	$ (8)
	Net equity in earnings of affiliates	-[1]	-[1]
Cross currency derivatives	Interest expense	-[1]	5
Foreign currency derivatives	Foreign currency transaction gains (losses)	-[1]	-[1]
Total		$ (7)	$ (3)

[1] De minimis amount.

The following table sets forth the gains (losses) recognized in earnings related to derivative instruments not designated as hedging instruments under the accounting standards for derivatives and hedging, for the three months ended March 31, 2011 and 2010:

	Classification in Condensed Consolidated Statement of Operations	Gains (Losses) Recognized in Earnings Three Months Ended March 31, 2011	2010
		(in millions)	
Interest rate derivatives	Interest expense	$ -	$ (4)
Foreign exchange derivatives	Foreign currency transaction gains (losses)	7	2
	Net equity in earnings of affiliates	-	1
Commodity derivatives	Non-regulated revenue	4	-
	Non-regulated cost of sales	1	4
Total		$ 12	$ 3

In addition, IPL has two derivative instruments for which the gains and losses are accounted for in accordance with accounting standards for regulated operations, as regulatory assets or liabilities. Gains and losses on these derivatives due to changes in the fair value of these derivatives are probable of recovery through future rates and are initially recognized as an adjustment to the regulatory asset or liability and recognized through earnings when the related costs are recovered through IPL s rates. Therefore, these gains and losses are excluded from the above table. The following table sets forth the change in regulatory assets and liabilities resulting from the change in the fair value of these derivatives for the three months ended March 31, 2011 and 2010:

	March 31, 2011	2010
	(in millions)	
(Increase) in regulatory assets	$ -	$ (1)
(Decrease) in regulatory liabilities	$ (1)	$ (1)

Credit Risk-Related Contingent Features

Gener, our business in Chile, has cross currency swap agreements with counterparties to swap Chilean inflation indexed bonds issued in December 2007 into U.S. Dollars. The derivative agreements contain credit contingent provisions which would permit the counterparties with which Gener is in a net liability position to require collateral credit support when the fair value of the derivatives exceeds the unsecured thresholds established in the agreement. These thresholds vary based on Gener s credit rating. If Gener s credit rating were to fall below the minimum threshold established in the swap agreements, the counterparties can demand immediate collateralization of the entire mark-to-market value of the swaps (excluding credit valuation adjustments) if Gener is in a net liability position. The mark-to-market value of the swaps was in a net asset position at March 31, 2011 and December 31, 2010. As of March 31, 2011 and December 31, 2010, Gener had not posted collateral to support these swaps.

6. INVESTMENTS IN AND ADVANCES TO AFFILIATES

In February 2011, the Company acquired a 49.6% interest in Entek Elektrik Uretim A.S. (Entek) for approximately $136 million. Entek owns and operates two gas-fired generation facilities with an aggregate capacity of 312 MW in Turkey, and is also engaged in an energy trading business. The Company has significant influence, but not control of Entek and accordingly the investment has been accounted for under the equity method of accounting.

7. FINANCING RECEIVABLES

Accounts and notes receivable are carried at amortized cost. The Company periodically assesses the collectability of accounts receivable considering factors such as specific evaluation of collectability, historical collection experience, the age of accounts receivable and other currently available evidence of the collectability, and records an allowance for doubtful accounts for the estimated uncollectable amount as appropriate. Certain of our businesses charge interest on accounts receivable either under contractual terms or where charging interest is a customary business practice. In such cases, interest income is recognized on an accrual basis. In situations where the collection of interest is uncertain, interest income is recognized as cash is received. Individual accounts and notes receivable are written off when they are no longer deemed collectable.

Included in Noncurrent other assets on the condensed consolidated balance sheets as of March 31, 2011 and December 31, 2010 are long-term financing receivables of $146 million and $151 million, respectively, primarily with certain Latin American governmental bodies. These receivables have contractual maturities of greater than one year and are being collected in installments. Of the total $146 million as of March 31, 2011, amounts of $78 million and $54 million, respectively, relate to our businesses in Argentina and the Dominican Republic. The remaining amounts relate to our distribution businesses in Brazil.

8. DEBT

The Company has two types of debt reported on its condensed consolidated balance sheet: non-recourse and recourse debt. Non-recourse debt is used to fund investments and capital expenditures for the construction and acquisition of electric power plants, wind projects, distribution companies and other project-related investments at our subsidiaries. Non-recourse debt is generally secured by the capital stock, physical assets, contracts and cash flows of the related subsidiary. Absent guarantees, intercompany loans or other credit support, the default risk is limited to the respective business and is without recourse to the Parent Company and other subsidiaries, though the Company s equity investments and/or subordinated loans to projects (if any) are at risk. Recourse debt is direct borrowings by the Parent Company and is used to fund development, construction or acquisitions, including serving as funding for equity investments or loans to the affiliates. The Parent Company s debt is, among other things, recourse to the Parent Company and is structurally subordinated to the affiliates debt.

The following table summarizes the carrying amount and estimated fair values of the Company s recourse and non-recourse debt as of March 31, 2011 and December 31, 2010:

	March 31, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(in millions)		
Non-recourse debt	$ 15,102	$ 15,396	$ 14,939	$ 15,269
Recourse debt	4,350	4,691	4,612	4,868
Total debt	$ 19,452	$ 20,087	$ 19,551	$ 20,137

Recourse and non-recourse debt are carried at amortized cost. The fair value of recourse debt is estimated based on quoted market prices. The fair value of non-recourse debt is estimated differently based upon the type of loan. The fair value of fixed rate loans is estimated using quoted market prices, if available, or a discounted cash flow analysis. In the discounted cash flow analysis, the discount rate is based on the credit rating of the individual debt instruments if available, or the credit rating of the subsidiary. If the subsidiary s credit rating is not available, a synthetic credit rating is determined using certain key metrics, including cash flow ratios and interest coverage, as well as other industry specific factors. For subsidiaries located outside the U.S., in the event that the country rating is lower than the credit rating previously determined, the country rating is used for the purposes of the discounted cash flow analysis. The fair value of recourse and non-recourse debt excludes accrued interest at the valuation date.

The estimated fair value was determined using available market information as of March 31, 2011. The Company is not aware of any factors that would significantly affect the fair value amounts subsequent to March 31, 2011.

Non-Recourse Debt

The following table summarizes the Company s subsidiary non-recourse debt in default or accelerated as of March 31, 2011 and is in the current portion of non-recourse debt unless otherwise indicated:

Subsidiary	Primary Nature of Default	March 31, 2011 Default	Net Assets
		(in millions)	
Maritza	Covenant	$ 1,015	$ 273
Sonel	Covenant	388	384
Kelanitissa	Covenant	28	35
Aixi	Payment	4	(8)
Total		$ 1,435	

Included in Current liabilities of discontinued and held for sale businesses in the condensed consolidated balance sheet as of March 31, 2011 is approximately $179 million of non-recourse debt relating to our businesses in New York, which has been classified as current due to certain facts and circumstances that create significant uncertainty about the business s ability to generate sufficient cash flows and remain in compliance with the terms of its contractual obligations in the next twelve months.

None of the subsidiaries that are currently in default are subsidiaries that met the applicable definition of materiality under AES corporate debt agreements as of March 31, 2011 in order to trigger an event of default or permit acceleration under such indebtedness. The bankruptcy or acceleration of material amounts of debt at such entities would cause a cross default under the recourse senior secured credit facility. However, as a result of additional dispositions of assets, other significant reductions in asset carrying values or other matters in the future that may impact our financial position and results of operations or the financial position or results of operations of the individual subsidiary, it is possible that one or more of these subsidiaries could fall within the definition of a material subsidiary and thereby a bankruptcy or an acceleration of its non-recourse debt trigger an event of default and possible acceleration of the indebtedness under the AES Parent Company s outstanding debt securities.

9. CONTINGENCIES AND COMMITMENTS

Environmental

The Company periodically reviews its obligations as they relate to compliance with environmental laws, including site restoration and remediation. As of March 31, 2011, the Company had recorded liabilities of $23 million for projected environmental remediation costs. Due to the uncertainties associated with environmental assessment and remediation activities, future costs of compliance or remediation could be higher or lower than the amount currently accrued. Based on currently available information and analysis, the Company believes that it is reasonably possible that costs associated with such liabilities, or as yet unknown liabilities, may exceed current reserves in amounts that could be material but cannot be estimated as of March 31, 2011.

The Company is subject to numerous environmental laws and regulations in the jurisdictions in which it operates. The Company expenses environmental regulation compliance costs as incurred unless the underlying expenditure qualifies for capitalization under its property, plant and equipment policies. The Company faces certain risks and uncertainties related to these environmental laws and regulations, including existing and potential greenhouse gas (GHG) legislation or regulations, and actual or potential laws and regulations pertaining to water discharges, waste management (including disposal of coal combustion byproducts), and certain air emissions, such as SO_2, NO_x, particulate matter and mercury. Such risks and uncertainties could result in increased capital expenditures or other compliance costs which could have a material adverse effect on certain of our U.S. or international subsidiaries and our consolidated results of operations.

Legislation and Regulation of GHG Emissions.

Currently, in the United States there is no Federal legislation establishing mandatory GHG emissions reduction programs (including CO_2) affecting the electric power generation facilities of the Company s subsidiaries. There are numerous state programs regulating GHG emissions from electric power generation facilities and there is a possibility that federal GHG legislation will be enacted within the next several years. Further, the United States Environmental Protection Agency (EPA) has adopted regulations pertaining to GHG emissions and has announced its intention to propose new regulations for electric generating units under Section 111 of the United States Clean Air Act (CAA).

Potential U.S. Federal GHG Legislation. Federal legislation passed the U.S. House of Representatives in 2009 that, if adopted, would have imposed a nationwide cap-and-trade program to reduce GHG emissions. This legislation was never signed into law, and is no longer under consideration. In the U.S. Senate, several different draft bills pertaining to GHG legislation have been considered, including comprehensive GHG legislation similar to the legislation that passed the U.S. House of Representatives and more limited legislation focusing only on the utility and electric generation industry. It is uncertain whether any legislation pertaining to GHG emissions will be voted on and passed by the U.S. Senate and House of Representatives. If any such legislation is enacted into law, the impact could be material to the Company.

EPA GHG Regulation. The EPA has promulgated regulations governing GHG emissions from automobiles under the CAA. The effect of EPA s regulation of GHG emissions from mobile sources is that certain provisions of the CAA will also apply to GHG emissions from existing stationary sources, including many U.S. power plants. In particular, beginning January 2, 2011, construction of new stationary sources and modifications to existing stationary sources that result in increased GHG emissions became subject to permitting requirements under the prevention of significant deterioration (PSD) program of the CAA. The PSD program, as currently applicable to GHG emissions, requires sources that emit above a certain threshold of GHGs to obtain PSD permits prior to commencement of new construction or modifications to existing facilities. In addition, major sources of GHG emissions may be required to amend, or obtain new, Title V air permits under the CAA to reflect any new applicable GHG emissions requirements for new construction or for modifications to existing facilities.

The EPA promulgated a final rule on June 3, 2010, (the Tailoring Rule) that sets thresholds for GHG emissions that would trigger PSD permitting requirements. The Tailoring Rule, which became effective in January of 2011, provides that sources already subject to PSD permitting requirements need to install Best Available Control Technology (BACT) for greenhouse gases if a proposed modification would result in the increase of more than 75,000 tons per year of GHG emissions. Also, under the Tailoring Rule, commencing in July of 2011, any new sources of GHG emissions that would emit over 100,000 tons per year of GHG emissions, in addition to any modification that would result in GHG emissions exceeding 75,000 tons per year, would require PSD review and be subject to related permitting requirements. The EPA anticipates that it will adjust downward the permitting thresholds of 100,000 tons and 75,000 tons for new sources and modifications, respectively, in future rulemaking actions. The Tailoring Rule substantially reduces the number of sources subject to PSD requirements for GHG emissions and the number of sources required to obtain Title V air permits, although new thermal power plants may still be subject to PSD and Title V requirements because annual GHG emissions from such plants typically far exceed the 100,000 ton threshold noted above. The 75,000 ton threshold for increased GHG emissions from modifications to existing sources may reduce the likelihood that future modifications to plants owned by some of our United States subsidiaries would trigger PSD requirements, although some projects that would expand capacity or electric output are likely to exceed this threshold, and in any such cases the capital expenditures necessary to comply with the PSD requirements could be significant.

In December 2010, the EPA entered into a settlement agreement with several states and environmental groups to resolve a petition for review challenging the EPA s new source performance standards (NSPS) rulemaking for electric utility steam generating units (EUSGUs) based on the NSPS s failure to address GHG emissions. Under the settlement agreement, the EPA has committed to propose GHG emissions standards for EUSGUs by July 26, 2011 and to finalize GHG emissions standards for EUSGUs by May 26, 2012. The NSPS will establish GHG emission standards for newly constructed and reconstructed EUSGUs. The NSPS also will establish guidelines regarding the best system for achieving further GHG emissions reductions from EUSGUs and, based on such guidelines, individual states will be required to submit plans to the EPA to establish GHG emission standards for existing EUSGUs within their states. It is impossible to estimate the impact and compliance cost associated with any future NSPS applicable to EUSGUs until such regulations are finalized. However, the compliance costs could have a material and adverse impact on our consolidated financial condition or results of operations.

Regional Greenhouse Gas Initiative. To date, the primary regulation of GHG emissions affecting the Company s U.S. plants has been through the Regional Greenhouse Gas Initiative (RGGI). Under RGGI, ten Northeastern States have coordinated to establish rules that require reductions in CO_2 emissions from power plant operations within those states through a cap-and-trade program. States participating in RGGI in which our subsidiaries have generating facilities include Connecticut, Maryland, New York and New Jersey. Under RGGI, power plants must acquire one carbon allowance through auction or in the emission trading markets for each ton of CO_2 emitted. As noted in the Company s 2010 Form 10-K, we have estimated the costs to the Company of compliance with RGGI to be approximately $15 million for 2011.

International GHG Regulation. The primary international agreement concerning GHG emissions is the Kyoto Protocol, which became effective on February 16, 2005 and requires the industrialized countries that have ratified it to significantly reduce their GHG emissions. The vast majority of the developing countries which have ratified the Kyoto Protocol have no GHG emissions reduction requirements. Many of the countries in which the Company s subsidiaries operate have no emissions reduction obligations under the Kyoto Protocol. In addition, of the 28 countries in which the Company s subsidiaries operate, all but one the United States (including Puerto Rico) have ratified the Kyoto Protocol. The Kyoto Protocol is currently expected to expire at the end of 2012, and countries have been unable to agree on a successor agreement. The next annual United Nations conference to develop a successor international agreement is scheduled for November 2011 in South Africa. It currently appears unlikely that a successor agreement will be reached at such conference; however, if a successor agreement is reached the impact could be material to the Company.

There is substantial uncertainty with respect to whether U.S. federal GHG legislation will be enacted into law, whether new country-specific GHG legislation will be adopted in countries in which our subsidiaries conduct business, and whether a new international agreement to succeed the Kyoto Protocol will be reached. There is additional uncertainty regarding the final provisions or implementation of any potential U.S. federal or foreign country GHG legislation, the EPA s rules regulating GHG emissions and any international agreement to succeed the Kyoto Protocol. In light of these uncertainties, the Company cannot accurately predict the impact on its consolidated results of operations or financial condition from potential U.S. federal or foreign country GHG legislation, the EPA s regulation of GHG emissions or any new international agreement on such emissions, or make a reasonable estimate of the potential costs to the Company associated with any such legislation, regulation or international agreement; however, the impact from any such legislation, regulation or international agreement could have a material adverse effect on certain of our U.S. or international subsidiaries and on the Company and its consolidated results of operations.

Other U.S. Air Emissions Regulations and Legislation

The Company s subsidiaries in the United States are subject to the Clean Air Act (CAA) and various state laws and regulations that regulate emissions of air pollutants, including SO_2, NO_X, particulate matter (PM), mercury and other hazardous air pollutants (HAPs).

The EPA promulgated the Clean Air Interstate Rule (CAIR) on March 10, 2005, which required allowance surrender for SO_2 and NO_X emissions from existing power plants located in 28 eastern states and the District of Columbia. CAIR was subsequently challenged in federal court, and on July 11, 2008, the United States Court of Appeals for the D.C. Circuit issued an opinion striking down much of CAIR and remanding it to the EPA. In response to the D.C. Circuit s opinion, on July 6, 2010, the EPA issued a new proposed rule (the Clean Air Transport Rule) to replace CAIR. The final Clean Air Transport Rule (Transport Rule) is scheduled to be issued by July 2011. The Transport Rule would require significant additional reductions in SO_2 and NO_X emissions in 31 states and the District of Columbia starting in 2012, including several states where subsidiaries of the Company conduct business.

The Transport Rule contemplates three possible options for reducing SO_2 and NO_X emissions in the designated states. The EPA s preferred option contemplates a set limit or budget on SO_2 and NO_X emissions for each of the states, with limited interstate trading of emissions allowances and unlimited intrastate trading of SO_2 and NO_X emissions allowances. Affected power plants would receive emissions allowances based on the applicable state emissions budgets. The EPA s second option under the Transport Rule would establish emission budgets for each state, but only allow intrastate trading of emissions allowances. The final option would set emission rate limitations for each power plant, but would allow for some intrastate averaging of emission rates. Under any of the proposed options, additional pollution control technology may be required by some of our subsidiaries, and the cost of implementing any such technology could affect the financial condition or results of operations of these subsidiaries or the parent company. The EPA has received public comments on the Transport Rule, and such public comments will be considered by the EPA prior to promulgating a final rule.

As a result of prior EPA determinations and the D.C. Circuit Court ruling, the EPA is obligated under Section 112 of the CAA to develop a rule requiring pollution controls for hazardous air pollutants, including mercury, hydrogen chloride, hydrogen fluoride, and nickel species from coal and oil-fired power plants. The EPA has entered into a consent decree under which it is obligated to finalize the rule by November 2011. In connection with such rule, the CAA requires the EPA to establish maximum achievable control technology (MACT) standards for each pollutant regulated under the rule. MACT is defined as the emission limitation achieved by the best performing 12% of sources in the source category. The EPA issued a proposed rule on March 16, 2011 that would establish national emissions standards for hazardous air pollutants (NESHAP) from coal- and oil-fired electric utility steam generating units. The rule, as currently proposed, may require all coal-fired power plants to install acid gas control technology, upgrade particulate control devices and/or install some other type of mercury control technology, such as sorbent injection. The EPA is receiving public comments on the proposed rule, and such public comments will be considered by the EPA prior to promulgating a final rule. Most of the United States coal-fired plants operated by the Company s subsidiaries have acid gas scrubbers or comparable control technologies, but as proposed there are other improvements to such control technologies that may be needed at some of our plants. Under the CAA, compliance is required within three years of the effective date of the rule; however, the compliance period for a unit, or group of units, may be extended by state permitting authorities (for one additional year) or through a determination by the President (for up to two additional years). At this time, the Company cannot predict the extent of the final regulations for hazardous air pollutants, but the cost of compliance with any such regulations could be material.

Other International Air Emissions Regulations and Legislation.

On January 18, 2011, the President of Chile approved a new air emissions regulation submitted to him by the national environmental regulatory agency (CONAMA). The new regulation establishes limits on emissions of NO_X, SO_2, metals and particulate matter for both existing and new thermal power plants, with more stringent limitations on new facilities. The regulation will become effective upon approval of the General Comptroller of Chile. The regulation will require AES Gener, our Chilean subsidiary, to install emissions reduction equipment at its existing thermal plants from late 2011 through 2015. The exact costs of compliance with such regulation have not yet been determined and the Company believes some of the compliance costs are contractually passed through to counterparties. However, the compliance costs could be material.

Cooling Water Intake Regulations.

The Company s U.S. facilities are subject to the U.S. Clean Water Act Section 316(b) rule issued by the EPA which seeks to protect fish and other aquatic organisms by requiring existing steam electric generating facilities to utilize the best technology available for cooling water intake structures. The EPA published a proposed rule establishing requirements under 316(b) regulations on April 20, 2011. The proposal, based on Section 316(b) of the U.S. Clean Water Act, establishes Best Technology Available (BTA) requirements regarding impingement standards with respect to aquatic organisms for all facilities that withdraw above 2 million gallons per day of water from certain water bodies and utilize at least 25% of the withdrawn water for cooling purposes. To meet these BTA requirements, as currently proposed, cooling water intake structures associated with once through cooling processes will need modifications of existing traveling screens that protect aquatic organisms and will need to add a fish return and handling system for each cooling system. Existing closed cycle cooling facilities may require upgrades to water intake structure systems. The proposal would also require comprehensive site-specific studies during the permitting process and may require closed-cycle cooling systems in order to meet BTA entrainment standards.

The EPA is accepting public comments on the proposed rule until July 2011, and until such regulations are final the EPA has instructed state regulatory agencies to use their best professional judgment in determining how to evaluate what constitutes best technology available for protecting fish and other aquatic organisms from cooling water intake structures. Certain states in which the Company operates power generation facilities, such as New York, have been delegated authority and are moving forward with best technology available determinations in the absence of any final rule from the EPA. On September 27, 2010, the California Office of Administrative Law approved a policy adopted by the California Water Resources Control Board with respect to power plant cooling water intake structures. This policy became effective on October 1, 2010, and establishes technology-based standards to implement Section 316(b) of the U.S. Clean Water Act. At this time, it is contemplated that the Company s Redondo Beach, Huntington Beach and Alamitos power plants in California will need to have in place best technology available by December 31, 2020, or repower the facilities. At present, the Company cannot predict the final requirements under Section 316(b) or whether compliance with the anticipated new 316(b) rule will have a material impact on our operations or results, but the Company expects that capital investments and/or modifications resulting from such requirements could be significant.

Waste Management.

In the course of operations, many of the Company s facilities generate coal combustion byproducts (CCB), including fly ash, requiring disposal or processing. On June 21, 2010 the EPA published in the Federal Register a proposed rule to regulate CCB under the Resource Conservation and Recovery Act (RCRA). The proposed rule provides two possible options for CCB regulation, and both options contemplate heightened structural integrity requirements for surface impoundments of CCB. The first option contemplates regulation of CCB as a hazardous waste subject to regulation under Subtitle C of the RCRA. Under this option, existing surface impoundments containing CCB would be required to be retrofitted with composite liners and these impoundments would likely be phased out over several years. State and/or federal permit programs would be developed for storage, transport and disposal of CCB. States could bring enforcement actions for non-compliance with permitting requirements, and the EPA would have oversight responsibilities as well as the authority to bring lawsuits for non-compliance. The second option contemplates regulation of CCB under Subtitle D of the RCRA. Under this option, the EPA would create national criteria applicable to CCB landfills and surface impoundments. Existing impoundments would also be required to be retrofitted with composite liners and would likely be phased out over several years. This option would not contain federal or state permitting requirements. The primary enforcement mechanism under regulation pursuant to Subtitle D would be private lawsuits.

The public comment period for this proposed regulation has expired, and EPA is required to consider the public comments prior to promulgating a final rule. Requirements under a final rule are expected to become effective by January 2012, with a compliance schedule of five years. While the exact impact and compliance cost associated with future regulations of CCB cannot be established until such regulations are finalized, there can be no assurance that the Company s businesses, financial condition or results of operations would not be materially and adversely affected by such regulations.

Guarantees, Letters of Credit and Commitments

In connection with certain project financing, acquisition, power purchase, and other agreements, AES has expressly undertaken limited obligations and commitments, most of which will only be effective or will be terminated upon the occurrence of future events. In the normal course of business, AES has entered into various agreements, mainly guarantees and letters of credit, to provide financial or performance assurance to third parties on behalf of AES businesses. These agreements are entered into primarily to support or enhance the creditworthiness otherwise achieved by a business on a stand-alone basis, thereby facilitating the availability of sufficient credit to accomplish their intended business purposes. Most of the contingent obligations primarily relate to future performance commitments which the Company or its businesses expect to fulfill within the normal course of business. The expiration dates of these guarantees vary from less than one year to more than 15 years.

The following table summarizes the Parent Company s contingent contractual obligations as of March 31, 2011. Amounts presented in the table below represent the Parent Company s current undiscounted exposure to guarantees and the range of maximum undiscounted potential exposure. The maximum exposure is not reduced by the amounts, if any, that could be recovered under the recourse or collateralization provisions in the guarantees. The amounts include obligations made by the Parent Company for the direct benefit of the lenders associated with the non-recourse debt of businesses of $39 million.

Contingent contractual obligations	**Amount (in millions)**	**Number of Agreements**	**Maximum Exposure Range for Each Agreement (in millions)**
Guarantees	$ 344	22	< $1 - $53
Letters of credit under the senior secured credit facility	28	14	< $1 - $16
Cash collateralized letters of credit	27	12	< $1 - $15
Total	$ 399	48	

As of March 31, 2011, the Company had $58 million of commitments to invest in subsidiaries under construction and to purchase related equipment that were not included in the letters of credit discussed above. The Company expects to fund these net investment commitments in 2011. The exact payment schedules will be dictated by the construction milestones. We expect to fund these commitments from a combination of current liquidity and internally generated Parent Company cash flow.

Litigation

The Company is involved in certain claims, suits and legal proceedings in the normal course of business, some of which are described below. The Company has accrued for litigation and claims where it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. The Company has evaluated claims in accordance with the accounting guidance for contingencies that it deems both probable and reasonably estimable and accordingly, has recorded aggregate reserves for all claims of approximately $466 million and $448 million as of March 31, 2011 and December 31, 2010, respectively. These reserves are reported on the condensed consolidated balance sheets within accrued and other liabilities and other long-term liabilities. A significant portion of the reserves relate to employment, non-income tax and customer disputes in international jurisdictions, principally Brazil. Certain of the Company s subsidiaries, principally in Brazil, are defendants in a number of labor and employment lawsuits. The complaints generally seek unspecified monetary damages, injunctive relief, or other relief. The subsidiaries have denied any liability and intend to vigorously defend themselves in all of these proceedings. There can be no assurance that these reserves will be adequate to cover all existing and future claims or that we will have the liquidity to pay such claims as they arise.

The Company believes, based upon information it currently possesses and taking into account established reserves for liabilities and its insurance coverage, that the ultimate outcome of these proceedings and actions is unlikely to have a material effect on the Company s financial statements. However, even where no reserve has been recognized, it is reasonably possible that some matters could be decided unfavorably to the Company and could require the Company, to pay damages or make expenditures in amounts that could be material but could not be estimated as of March 31, 2011. The material contingencies where a loss is reasonably possible are described below. In aggregate, the Company estimates that the range of potential losses related to these material contingences to be up to $1.8 billion. The amounts considered reasonably possible do not include amounts reserved discussed above. Where a loss or range of loss cannot be estimated, a statement to this effect has been included in the applicable case descriptions presented below.

In 1989, Centrais Elétricas Brasileiras S.A. (Eletrobrás) filed suit in the Fifth District Court in the State of Rio de Janeiro against Eletropaulo Eletricidade de São Paulo S.A. (EEDSP) relating to the methodology for calculating monetary adjustments under the parties financing agreement. In April 1999, the Fifth District Court found for Eletrobrás and in September 2001, Eletrobrás initiated an execution suit in the Fifth District Court to collect approximately R$1.1 billion ($668 million) from Eletropaulo (as estimated by Eletropaulo) and a lesser amount from an unrelated company, Companhia de Transmissão de Energia Elétrica Paulista (CTEEP) (Eletropaulo and CTEEP were spun off from EEDSP pursuant to its privatization in 1998). In November 2002, the Fifth District Court rejected Eletropaulo s defenses in the execution suit. Eletropaulo appealed and in September 2003, the Appellate Court of the State of Rio de Janeiro (AC) ruled that Eletropaulo was not a proper party to the litigation because any alleged liability had been transferred to CTEEP pursuant to the privatization. In June 2006, the Superior Court of Justice (SCJ) reversed the Appellate Court s decision and remanded the case to the Fifth District Court for further proceedings, holding that Eletropaulo s liability, if any, should be determined by the Fifth District Court. Eletropaulo s subsequent appeals to the Special Court (the highest court within the SCJ) and the Supreme Court of Brazil were dismissed. Eletrobrás later requested that the amount of Eletropaulo s alleged debt be determined by an accounting expert appointed by the Fifth District Court. Eletropaulo consented to the appointment of such an expert, subject to a reservation of rights. In February 2010, the Fifth District Court appointed an accounting expert to determine the amount of the alleged debt and the responsibility for its payment in light of the privatization, in accordance with the methodology proposed by Eletrobrás. Pursuant to its reservation of rights, Eletropaulo filed an interlocutory appeal with the AC asserting that the expert was required to determine the issues in accordance with the methodology proposed by Eletropaulo, and that Eletropaulo should be entitled to take discovery and present arguments on the issues to be determined by the expert. In April 2010, the AC issued a decision agreeing with Eletropaulo s arguments and directing the Fifth District Court to proceed accordingly. Eletrobrás has restarted the accounting proceedings at the Fifth District Court, which will proceed in accordance with the AC s April 2010 decision. In the Fifth District Court proceedings, the expert s conclusions will be subject to the Fifth District Court s review and approval. If Eletropaulo is determined to be responsible for the debt, after the amount of the alleged debt is determined, Eletrobrás will be entitled to resume the execution suit in the Fifth District Court at any time. If Eletrobrás does so, Eletropaulo will be required to provide security in the amount of its alleged liability. In that case, if Eletrobrás requests the seizure of such security and the Fifth District Court grants such request, Eletropaulo s results of operations may be materially adversely affected, and in turn the Company s results of operations could be materially adversely affected. In addition, in February 2008, CTEEP filed a lawsuit in the Fifth District Court against Eletrobrás and Eletropaulo seeking a declaration that CTEEP is not liable for any debt under the financing agreement. The parties are disputing the proper venue for the CTEEP lawsuit. Eletropaulo believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In August 2000, the Federal Energy Regulatory Commission (FERC) announced an investigation into the organized California wholesale power markets to determine whether rates were just and reasonable. Further investigations involved alleged market manipulation. FERC requested documents from each of the AES Southland, LLC plants and AES Placerita, Inc. AES Southland and AES Placerita have cooperated fully with the FERC investigations. AES Southland was not subject to refund liability because it did not sell into the organized spot markets due to the nature of its tolling agreement. After hearings at FERC, AES Placerita was found subject to refund liability of $588,000 plus interest for spot sales to the California Power Exchange from October 2, 2000 to June 20, 2001. As FERC investigations and hearings progressed, numerous appeals on related issues were filed with the U.S. Court of Appeals for the Ninth Circuit. Over the years, the Ninth Circuit issued several opinions that had the potential to expand the scope of the FERC proceedings and increase refund exposure for AES Placerita and other sellers of electricity. Following remand of one of the Ninth Circuit appeals in March 2009, FERC started a new hearing process involving AES Placerita and other sellers. In May 2009, AES Placerita entered into a settlement, approved by FERC in July 2009, concerning the claims before FERC against AES Placerita relating to the California energy crisis of 2000-2001, including the California refund proceeding. Pursuant to the settlement, AES Placerita paid $6 million and assigned a receivable of $168,119 due to it from the California Power Exchange in return for a release of all claims against it at FERC by the settling parties and other consideration. More than 98% of the buyers in the market elected to join the settlement. A small amount of AES Placerita s settlement payment was placed in escrow for buyers that did not join the settlement (non-settling parties). It is unclear whether the escrowed funds will be enough to satisfy any additional sums that might be determined to be owed to non-settling parties at the conclusion of the FERC proceedings concerning the California energy crisis. However, any such additional sums are expected to be immaterial to the Company s consolidated financial statements. In November 2009, one non-settling party, the Sacramento Municipal Utility District (SMUD), filed an appeal of the FERC s approval of the settlement which is pending in the Ninth Circuit. SMUD s appeal has been stayed pending further order of the court. The settlement agreement is still effective and will continue to remain effective unless it is vacated by the Ninth Circuit. SMUD has reached a settlement in principal with buyers of electricity that, if approved by FERC, will leave only immaterial claims of non-settling parties against AES Placerita. As a consequence of SMUD s settlement, it will withdraw its appeal of the Placerita order. In March 2011, the FERC approved the sale of AES Placerita to an unaffiliated entity. Pursuant to the stock purchase agreement, certain AES affiliates agreed to indemnify the purchaser against losses related to the claims against AES Placerita in the FERC proceedings, which losses, if any, are expected to be immaterial to the Company s consolidated financial statements.

In August 2001, the Grid Corporation of Orissa, India, now Gridco Ltd. (Gridco), filed a petition against the Central Electricity Supply Company of Orissa Ltd. (CESCO), an affiliate of the Company, with the Orissa Electricity Regulatory Commission (OERC), alleging that CESCO had defaulted on its obligations as an OERC-licensed distribution company, that CESCO management abandoned the management of CESCO, and asking for interim measures of protection, including the appointment of an administrator to manage CESCO. Gridco, a state-owned entity, is the sole wholesale energy provider to CESCO. Pursuant to the OERC s August 2001 order, the management of CESCO was replaced with a government administrator who was appointed by the OERC. The OERC later held that the Company and other CESCO shareholders were not necessary or proper parties to the OERC proceeding. In August 2004, the OERC issued a notice to CESCO, the Company and others giving the recipients of the notice until November 2004 to show cause why CESCO s distribution license should not be revoked. In response, CESCO submitted a business plan to the OERC. In February 2005, the OERC issued an order rejecting the proposed business plan. The order also stated that the CESCO distribution license would be revoked if an acceptable business plan for CESCO was not submitted to and approved by the OERC prior to March 31, 2005. In its April 2, 2005 order, the OERC revoked the CESCO distribution license. CESCO has filed an appeal against the April 2, 2005 OERC order and that appeal remains pending in the Indian courts. In addition, Gridco asserted that a comfort letter issued by the Company in connection with the Company s indirect investment in CESCO obligates the Company to provide additional financial support to cover all of CESCO s financial obligations to Gridco. In December 2001, Gridco served a notice to arbitrate pursuant to the Indian Arbitration and Conciliation Act of 1996 on the Company, AES Orissa Distribution Private Limited (AES ODPL), and Jyoti Structures (Jyoti) pursuant to the terms of the CESCO Shareholders Agreement between Gridco, the Company, AES ODPL, Jyoti and CESCO (the CESCO arbitration). In the arbitration, Gridco appeared to be seeking approximately $189 million in damages, plus undisclosed penalties and interest, but a detailed alleged damage analysis was not filed by Gridco. The Company counterclaimed against Gridco for damages. In June 2007, a 2-to-1 majority of the arbitral tribunal rendered its award rejecting Gridco s claims and holding that none of the respondents, the Company, AES ODPL, or Jyoti, had any liability to Gridco. The respondents counterclaims were also rejected. In September 2007, Gridco filed a challenge of the arbitration award with the local Indian court. In June 2008, Gridco filed a separate application with the local Indian court for an order enjoining the Company from selling or otherwise transferring its shares in Orissa Power Generation Corporation Ltd. s (OPGC), an equity method investment, and requiring the Company to provide security in the amount of the contested damages in the CESCO arbitration until Gridco s challenge to the arbitration award is resolved. In June 2010, a 2-to-1 majority of the arbitral tribunal awarded the Company some of its costs relating to the arbitration. In August 2010, Gridco filed a challenge of the cost award with the local Indian court. The Company believes that it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In March 2003, the office of the Federal Public Prosecutor for the State of São Paulo, Brazil (MPF) notified AES Eletropaulo that it had commenced an inquiry related to the BNDES financings provided to AES

Elpa and AES Transgás and the rationing loan provided to Eletropaulo, changes in the control of Eletropaulo, sales of assets by Eletropaulo and the quality of service provided by Eletropaulo to its customers, and requested various documents from Eletropaulo relating to these matters. In July 2004, the MPF filed a public civil lawsuit in the Federal Court of São Paulo (FSCP) alleging that BNDES violated Law 8429/92 (the Administrative Misconduct Act) and BNDES s internal rules by: (1) approving the AES Elpa and AES Transgás loans; (2) extending the payment terms on the AES Elpa and AES Transgás loans; (3) authorizing the sale of Eletropaulo s preferred shares at a stock-market auction; (4) accepting Eletropaulo s preferred shares to secure the loan provided to Eletropaulo; and (5) allowing the restructurings of Light Serviços de Eletricidade S.A. and Eletropaulo. The MPF also named AES Elpa and AES Transgás as defendants in the lawsuit because they allegedly benefited from BNDES s alleged violations. In May 2006, the FCSP ruled that the MPF could pursue its claims based on the first, second, and fourth alleged violations noted above. The MPF subsequently filed an interlocutory appeal with the Federal Court of Appeals (FCA) seeking to require the FCSP to consider all five alleged violations. Also, in July 2006, AES Elpa and AES Transgás filed an interlocutory appeal with the FCA, which was subsequently consolidated with the MPF s interlocutory appeal, seeking a transfer of venue and to enjoin the FCSP from considering any of the alleged violations. In June 2009, the FCA granted the injunction sought by AES Elpa and AES Transgás and transferred the case to the Federal Court of Rio de Janeiro. In May 2010, the MPF filed an appeal with the Superior Court of Justice challenging the transfer. The MPF s lawsuit before the FCSP has been stayed pending a final decision on the interlocutory appeals. AES Elpa and AES Brasiliana (the successor of AES Transgás) believe they have meritorious defenses to the allegations asserted against them and will defend themselves vigorously in these proceedings; however, there can be no assurances that they will be successful in their efforts.

In July 2004, the Corporación Dominicana de Empresas Eléctricas Estatales (CDEEE) filed lawsuits against Itabo, an affiliate of the Company, in the First and Fifth Chambers of the Civil and Commercial Court of First Instance for the National District. CDEEE alleges in both lawsuits that Itabo spent more than was necessary to rehabilitate two generation units of an Itabo power plant and, in the Fifth Chamber lawsuit, that those funds were paid to affiliates and subsidiaries of AES Gener and Coastal Itabo, Ltd. (Coastal), a former shareholder of Itabo, without the required approval of Itabo s board of administration. In the First Chamber lawsuit, CDEEE seeks an accounting of Itabo s transactions relating to the rehabilitation. In November 2004, the First Chamber dismissed the case for lack of legal basis. On appeal, in October 2005 the Court of Appeals of Santo Domingo ruled in Itabo s favor, reasoning that it lacked jurisdiction over the dispute because the parties contracts mandated arbitration. The Supreme Court of Justice is considering CDEEE s appeal of the Court of Appeals decision. In the Fifth Chamber lawsuit, which also names Itabo s former president as a defendant, CDEEE seeks $15 million in damages and the seizure of Itabo s assets. In October 2005, the Fifth Chamber held that it lacked jurisdiction to adjudicate the dispute given the arbitration provisions in the parties contracts. The First Chamber of the Court of Appeal ratified that decision in September 2006. In a related proceeding, in May 2005, Itabo filed a lawsuit in the U.S. District Court for the Southern District of New York seeking to compel CDEEE to arbitrate its claims. The petition was denied in July 2005. Itabo s appeal of that decision to the U.S. Court of Appeals for the Second Circuit has been stayed since September 2006. Further, in September 2006, in an International Chamber of Commerce arbitration, an arbitral tribunal determined that it lacked jurisdiction to decide arbitration claims concerning these disputes. Itabo believes it has meritorious claims and defenses and will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In July 2007, the Competition Committee of the Ministry of Industry and Trade of the Republic of Kazakhstan (the Competition Committee) ordered Nurenergoservice, an AES subsidiary, to pay approximately KZT 18 billion ($122 million) for alleged antimonopoly violations in 2005 through the first quarter of 2007. The Competition Committee s order was affirmed by the economic court in April 2008 (April 2008 Decision). The economic court also issued an injunction to secure Nurenergoservice s alleged liability, freezing Nurenergoservice s bank accounts and prohibiting Nurenergoservice from transferring or disposing of its property. Nurenergoservice s subsequent appeals to the court of appeals were rejected. In February 2009, the Antimonopoly Agency (the Competition Committee s successor) seized approximately KZT 778 million ($5 million) from a frozen Nurenergoservice bank account in partial satisfaction of Nurenergoservice s alleged damages liability. However, on appeal to the Kazakhstan Supreme Court, in October 2009, the Supreme Court annulled the decisions of the lower courts because of procedural irregularities and remanded the case to the economic court for reconsideration. On remand, in January 2010, the economic court reaffirmed its April 2008 Decision. Nurenergoservice s appeals in the court of appeals (first panel) and the court of appeals (second panel) were unsuccessful. Nurenergoservice intends to file a further appeal to the Kazakhstan Supreme Court. In separate but related proceedings, in August 2007, the Competition Committee ordered Nurenergoservice to pay approximately KZT 1.8 billion ($12 million) in administrative fines for its alleged antimonopoly violations. Nurenergoservice s appeal to the administrative court was rejected in February 2009. Given the adverse court decisions against Nurenergoservice, the Antimonopoly Agency may attempt to seize Nurenergoservice s remaining assets, which are immaterial to the Company s consolidated financial statements. The Antimonopoly Agency has not indicated whether it intends to assert claims against Nurenergoservice for alleged antimonopoly violations post first quarter 2007. Nurenergoservice believes it has meritorious defenses to the claims asserted against it; however, there can be no assurances that it will prevail in these proceedings.

In April 2009, the Antimonopoly Agency initiated an investigation of the power sales of Ust-Kamenogorsk HPP (UK HPP) and Shulbinsk HPP, hydroelectric plants under AES concession (collectively, the Hydros), in January through February 2009. The investigation of both Hydros has now been completed. The Antimonopoly Agency determined that the Hydros abused their market position and charged monopolistically high prices for power in January through February 2009. The Agency sought an order from the administrative court requiring UK HPP to pay an administrative fine of approximately KZT 120 million ($1 million) and to disgorge profits for the period at issue, estimated by the Antimonopoly Agency to be approximately KZT 440 million ($3 million). No fines or damages have been paid to date, however, as the proceedings in the administrative court have been suspended due to the initiation of related criminal proceedings against officials of the Hydros. In the course of criminal proceedings, the financial police have expanded the periods at issue to the entirety of 2009 in the case of UK HPP and from January through October 2009 in the case of Shulbinsk HPP, and sought increased damages of KZT 1.2 billion ($8 million) in the case of UK HPP and KZT 1.3 billion ($9 million) in the case of Shulbinsk HPP. The Hydros believe they have meritorious defenses and will assert them vigorously in these proceedings; however, there can be no assurances that they will be successful in their efforts.

In July 1993 the Public Attorney s office filed a claim against Eletropaulo, the Sao Paulo State Government, SABESP (a state-owned company), CETESB (a state-owned company) and DAEE (the municipal Water and Electric Energy Department) alleging that they were liable for pollution of the Billings Reservoir as a result of pumping water from the Pinheiros River into the Billings Reservoir. The events in question occurred while Eletropaulo was a state-owned company. An initial lower court decision in 2007 found the parties liable for the payment of approximately R$670 million ($407 million) for remediation. Eletropaulo subsequently appealed the decision to the Appellate Court of the State of Sao Paulo which reversed the lower court decision. In 2009, the Public Attorney s Office has filed appeals to both Superior Court of Justice (SCJ) and the Supreme Court (SC) and such appeals were answered by Eletropaulo in the fourth quarter of 2009. Eletropaulo believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In February 2009, a CAA Section 114 information request from the EPA regarding Cayuga and Somerset was received. The request seeks various operating and testing data and other information regarding certain types of projects at the Cayuga and Somerset facilities, generally for the time period from January 1, 2000 through the date of the information request. This type of information request has been used in the past to assist the EPA in determining whether a plant is in compliance with applicable standards under the CAA. Cayuga and Somerset responded to the EPA s information request in June 2009, and they are awaiting a response from the EPA regarding their submittal. At this time, it is not possible to predict what impact, if any, this request may have on the Company, its results of operations or its financial position.

On February 2, 2009, the Cayuga facility received a Notice of Violation from the New York State Department of Environmental Conservation (NYSDEC) that the facility had exceeded the permitted volume limit of coal ash that can be disposed of in the on-site landfill. Cayuga has met with NYSDEC and submitted a Landfill Liner Demonstration Report to them. Such report found that the landfill has adequate engineering integrity to support the additional coal ash and there is no inherent environmental threat. NYSDEC has indicated they accept the finding of the report. A permit modification was approved by the NYSDEC on May 14, 2010 and such permit modification allows for closure of this approximately 10-acre portion of the landfill. The construction in accordance with the approved permit modification was completed in November 2010 and the certification report for this construction project is currently being drafted to submit to the NYSDEC in the second quarter of 2011. While at this time it is not possible to predict what impact, if any, this matter may have on the Company, its results of operations or its financial position, based upon the discussions to date, the Company does not believe the impact will be material.

In March 2009, AES Uruguaiana Empreendimentos S.A. (AESU) initiated arbitration in the International Chamber of Commerce (ICC) against YPF S.A. (YPF) seeking damages and other relief relating to YPF s breach of the parties gas supply agreement (GSA). Thereafter, in April 2009, YPF initiated arbitration in the ICC against AESU and two unrelated parties, Companhia de Gas do Esado do Rio Grande do Sul and Transportador de Gas del Mercosur S.A. (TGM), claiming that AESU wrongfully terminated the GSA and caused the termination of a transportation agreement (TA) between YPF and TGM (YPF Arbitration). YPF seeks an unspecified amount of damages from AESU, a declaration that YPF s performance was excused under the GSA due to certain alleged force majeure events, or, in the alternative, a declaration that the GSA and the TA should be terminated without a finding of liability against YPF because of the allegedly onerous obligations imposed on YPF by those agreements. In addition, in the YPF Arbitration, TGM asserts that if it is determined that AESU is responsible for the termination of the GSA, AESU is liable for TGM s alleged losses, including losses under the TA. In April 2011, the arbitrations were consolidated into a single proceeding, and a new procedural schedule was established for the consolidated proceeding. The hearing on liability issues will take place in December 2011. AESU believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously; however, there can be no assurances that it will be successful in its efforts.

In June 2009, the Inter-American Commission on Human Rights of the Organization of American States (IACHR) requested that the Republic of Panama suspend the construction of AES Changuinola S.A. s hydroelectric project (Project) until the bodies of the Inter-American human rights system can issue a final decision on a petition (286/08) claiming that the construction violates the human rights of alleged indigenous communities. In July 2009, Panama responded by informing the IACHR that it would not suspend construction of the Project and requesting that the IACHR revoke its request. In June 2010, the Inter-American Court of Human Rights vacated the IACHR s request. With respect to the merits of the underlying petition, the IACHR heard arguments by the communities and Panama in November 2009, but has not issued a decision to date. The Company cannot predict Panama s response to any determination on the merits of the petition by the bodies of the Inter-American human rights system. While at this time it is not possible to predict what impact, if any, this matter may have on the Company, its results of operations or its financial position, based upon the discussions to date, the Company does not believe the impact will be material.

In July 2009, AES Energía Cartagena S.R.L. (AES Cartagena) received notices from the Spanish national energy regulator, Comisión Nacional de Energía (CNE), stating that the proceeds of the sale of electricity from AES Cartagena s plant should be reduced by roughly the value of the CO_2 allowances that were granted to AES Cartagena for free for the years 2007, 2008, and the first half of 2009. In particular, the notices stated that CNE intended to invoice AES Cartagena to recover that value, which CNE calculated as approximately 20 million ($28 million) for 2007-2008 and an amount to be determined for the first half of 2009. In September 2009, AES Cartagena received invoices for 523,548 (approximately $738,000) for the allowances granted for free for 2007 and 19,907,248 (approximately $28 million) for 2008. In July 2010, AES Cartagena received an invoice for approximately 5 million ($7 million) for the allowances granted for free for the first half of 2009. AES Cartagena does not expect to be charged for CO_2 allowances issued free of charge for subsequent periods. AES Cartagena has paid the amounts invoiced and has filed challenges to the CNE s demands in the Spanish judicial system. There can be no assurances that the challenges will be successful. AES Cartagena has demanded indemnification from its fuel supply and electricity toller, GDF-Suez, in relation to the CNE invoices under the long-term energy agreement (the Energy Agreement) with GDF-Suez. However, GDF-Suez has disputed that it is responsible for the CNE invoices under the Energy Agreement. Therefore, in September 2009, AES Cartagena initiated arbitration against GDF-Suez, seeking to recover the payments made to CNE. In the arbitration, AES Cartagena also seeks a determination that GDF-Suez is responsible for procuring and bearing the cost of CO_2 allowances that are required to offset the CO_2 emissions of AES Cartagena s power plant, which is also in dispute between the parties. To date, AES Cartagena has paid approximately 25 million ($35 million) for the CO_2 allowances that have been required to offset 2008, 2009 and 2010 CO_2 emissions. AES Cartagena expects that allowances will need to be purchased to offset emissions for subsequent years. The evidentiary hearing in the arbitration took place from May 31-June 4, 2010, and closing arguments were heard on September 1, 2010. In February 2011, the arbitral tribunal requested further briefing on certain issues in the arbitration, which was later submitted by the parties. The tribunal has the matter under consideration. If AES Cartagena does not prevail in the arbitration and is required to bear the cost of carbon compliance, its results of operations could be materially adversely affected and, in turn, there could be a material adverse effect on the Company and its results of operations. AES Cartagena believes it has meritorious claims and will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In September 2009, the Public Defender s Office of the State of Rio Grande do Sul (PDO) filed a class action against AES Sul in the 16th District Court of Porto Alegre, Rio Grande do Sul (District Court), claiming that AES Sul has been illegally passing PIS and COFINS taxes (taxes based on AES Sul s income) to consumers. According to ANEEL s Order No. 93/05, the federal laws of Brazil, and the Brazilian Constitution, energy companies such as AES Sul are entitled to highlight PIS and COFINS taxes in power bills to final consumers, as the cost of those taxes is included in the energy tariffs that are applicable to final consumers. Before AES Sul had been served with the action, the District Court dismissed the lawsuit in October 2009 on the ground that AES Sul had been properly highlighting PIS and COFINS taxes in consumer bills in accordance with Brazilian law. In April 2010, the PDO appealed to the Appellate Court of the State of Rio Grande do Sul (AC). In November 2010, the AC affirmed the dismissal. The PDO did not appeal, and the District Court s decision became final and unappealable in March 2011.

In November 2009, April 2010, December 2010, and April 2011, substantially similar personal injury lawsuits were filed by a total of 41 residents and estates in the Dominican Republic against the Company, AES Atlantis, Inc., AES Puerto Rico, LP, AES Puerto Rico, Inc., and AES Puerto Rico Services, Inc., in the Superior Court for the State of Delaware. In each lawsuit the plaintiffs allege that the coal combustion byproducts of AES Puerto Rico s power plant were illegally placed in the Dominican Republic in October 2003 through March 2004 and subsequently caused the plaintiffs birth defects, other personal injuries, and/or deaths. The plaintiffs do not quantify their alleged damages, but generally allege that they are entitled to compensatory and punitive damages. The AES defendants have moved for partial dismissal of both the November 2009 and April 2010 lawsuits on various grounds. (By agreement with the plaintiffs, the AES defendants have not yet responded to the December 2010 or April 2011 lawsuits, and will not do so until after the Superior Court rules on the pending partial dismissal motions in the other cases.) In September 2010, the Superior Court heard arguments on the motions. The Superior Court dismissed the plaintiffs fraud allegations without prejudice to replead, and the plaintiffs filed amended complaints in November 2010. The AES defendants have filed a renewed motion to dismiss the amended issues. A ruling on that motion is pending. Also, a ruling on the remaining claims (other than fraud) addressed in the original partial dismissal motions is still pending. The AES defendants believe they have meritorious defenses to the claims asserted against them and will defend themselves vigorously; however, there can be no assurances that they will be successful in their efforts. While at this time it is not possible to predict what impact, if any, this matter may have on the Company, its results of operations or its financial position, based upon the discussions to date, the Company does not believe the impact will be material.

On December 21, 2010, AES-3C Maritza East 1 EOOD, which owns an unfinished 670 MW lignite-fired power plant in Bulgaria, made the first in a series of demands on the performance bond securing the construction

Contractor s obligations under the parties EPC Contract. The Contractor failed to complete the plant on schedule. The total amount demanded by Maritza under the performance bond is approximately 155 million ($219 million). However, the Contractor has obtained an injunction from a French court purportedly preventing the issuing bank from honoring the bond demands. Maritza is seeking relief in the French and English courts to attempt to lift that injunction or otherwise obtain payment on its demands. In addition, in December 2010, the Contractor issued a notice of dispute alleging that the lignite that has been supplied by Maritza for commissioning of the power plant is out of specification, allegedly entitling the Contractor to an extension of time to complete the power plant, an increase to the contract price of approximately 62 million ($87 million), and other relief. The Contractor thereafter advised Maritza that it had stopped commissioning of the power plant s two units because of the characteristics of the lignite supplied, and, in January 2011, initiated arbitration on its lignite claim. The Contractor later added claims seeking further extensions of time and an additional 10 million ($14 million) relating to the alleged unavailability of the grid during commissioning. Maritza has rejected the Contractor s claims and asserted counterclaims for delay liquidated damages and other relief relating to the Contractor s failure to complete the power plant and other breaches of the EPC contract. Maritza has also terminated the construction contract for cause and asserted arbitration claims against the Contractor relating to the termination. Maritza believes it has meritorious claims and defenses and will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

10. PENSION PLANS

Total pension cost for the three months ended March 31, 2011 and 2010 included the following components:

	Three Months Ended March 31, 2011		2010	
	U.S.	Foreign	U.S.	Foreign
	(in millions)			
Service cost	$ 2	$ 5	$ 2	$ 5
Interest cost	8	142	8	125
Expected return on plan assets	(8)	(128)	(8)	(105)
Amortization of prior service cost	1	-	1	-
Amortization of net loss	3	6	3	3
Loss on curtailment	-	4	-	-
Total pension cost	$ 6	$ 29	$ 6	$ 28

Total employer contributions for the three months ended March 31, 2011 for the Company s U.S. and foreign subsidiaries were $6 million and $42 million, respectively. The expected remaining scheduled annual employer contributions for 2011 are $31 million for U.S. subsidiaries and $126 million for foreign subsidiaries.

11. EQUITY

STOCK REPURCHASE PROGRAM

In July 2010, the Company s Board of Directors approved a stock repurchase program under which the Company may repurchase up to $500 million of AES common stock. The Board authorization permits the Company to repurchase stock through a variety of methods, including open market repurchases and/or privately negotiated transactions. The original authorization was set to expire on December 31, 2010; however, in December 2010, the Board authorized an extension of the stock repurchase program. There can be no assurance as to the amount, timing or prices of repurchases, which may vary based on market conditions and other factors. The stock repurchase program may be modified, extended or terminated by the Board of Directors at any time. During the three months ended March 31, 2011, shares of common stock repurchased under this plan totaled 4,943,011 at a total cost of

$63 million plus a nominal amount of commissions (average of $12.68 per share including commissions), bringing the cumulative total purchases under the program to 13,325,836 shares at a total cost of $162 million plus a nominal amount of commissions (average of $12.16 per share including commissions). There was $338 million remaining under the stock repurchase program available for future repurchases at March 31, 2011.

The shares of stock repurchased have been classified as treasury stock and accounted for using the cost method. A total of 21,787,992 and 17,287,073 shares were held as treasury stock at March 31, 2011 and December 31, 2010, respectively. The Company has not retired any shares held in treasury during the three months ended March 31, 2011.

COMPREHENSIVE INCOME

The components of comprehensive income (loss) for the three months ended March 31, 2011 and 2010 were as follows:

	March 31, 2011	March 31, 2010
	(in millions)	
Net income	$ 483	$ 402
Change in fair value of available-for-sale securities, net of income tax benefit of $1 and $2, respectively	(1)	(4)
Foreign currency translation adjustments, net of income tax (expense) benefit of $(4) and $5, respectively	128	(134)
Derivative activity:		
Reclassification to earnings, net of income tax (expense) of $(8) and $(11), respectively	30	32
Change in derivative fair value, net of income tax (expense) benefit of $(9) and $13, respectively	41	(66)
Total change in fair value of derivatives	71	(34)
Change in unfunded pension obligation, net of income tax (expense) of $(2) and $(1), respectively	3	2
Other comprehensive income (loss)	201	(170)
Comprehensive income	684	232
Less: Comprehensive income attributable to noncontrolling interests[1]	(325)	(164)
Comprehensive income attributable to The AES Corporation	$ 359	$ 68

(1) Includes the income attributed to noncontrolling interests in the form of common securities and dividends on preferred stock of subsidiary.

The components of accumulated other comprehensive loss as of March 31, 2011 and December 31, 2010 were as follows:

	March 31, 2011	December 31, 2010
	(in millions)	
Foreign currency translation adjustment	$ 1,749	$ 1,824
Unrealized derivative losses, net	283	344
Unfunded pension obligation	216	216
Securities available-for-sale	-	(1)
Accumulated other comprehensive loss	$ 2,248	$ 2,383

12. SEGMENTS

The management reporting structure is organized along our two lines of business (Generation and Utilities) and three regions: (1) Latin America & Africa; (2) North America; and (3) Europe, Middle East & Asia (collectively EMEA), each managed by a regional president. The segment reporting structure uses the Company s management reporting structure as its foundation to reflect how the Company manages the business internally. The Company applied the segment reporting accounting guidance, which provides certain quantitative thresholds and aggregation criteria, and concluded it has the following six reportable segments:

Latin America Generation;

Latin America Utilities;

North America Generation;

North America Utilities;

Europe Generation;

Asia Generation.

Corporate and Other The Company s Europe Utilities, Africa Utilities, Africa Generation, Wind Generation and Climate Solutions operating segments are reported within Corporate and Other because they do not meet the criteria to allow for aggregation with another operating segment or the quantitative thresholds that would require separate disclosure under segment reporting accounting guidance. None of these operating segments are currently material to our presentation of reportable segments, individually or in the aggregate. AES Solar and certain other unconsolidated businesses are accounted for using the equity method of accounting; therefore, their operating results are included in Net Equity in Earnings of Affiliates on the face of the Consolidated Statements of Operations, not in revenue or gross margin. Corporate and Other also includes costs related to corporate overhead costs which are not directly associated with the operations of our six reportable segments and other intercompany charges such as self-insurance premiums which are fully eliminated in consolidation.

The Company uses Adjusted Gross Margin, a non-GAAP measure, to evaluate the performance of its segments. Adjusted Gross Margin is defined by the Company as: Gross Margin plus depreciation and amortization less general and administrative expenses.

Segment revenue includes inter-segment sales related to the transfer of electricity from generation plants to utilities within Latin America. No material inter-segment revenue relationships exist between other segments. Corporate allocations include certain self insurance activities which are reflected within segment Adjusted Gross Margin. All intra-segment activity has been eliminated with respect to revenue and Adjusted Gross Margin within the segment. Inter-segment activity has been eliminated within the total consolidated results. All balance sheet information for businesses that were discontinued or classified as held for sale as of March 31, 2011 is segregated and is shown in the line Discontinued Businesses in the accompanying segment tables.

The tables below present the breakdown of business segment balance sheet and income statement data for the three months ended March 31, 2011 and 2010:

	Total Revenue 2011	Total Revenue 2010	Intersegment 2011	Intersegment 2010	External Revenue 2011	External Revenue 2010
	(in millions)					
Revenue						
Latin America Generation	$ 1,131	$ 983	$ (251)	$ (255)	$ 880	$ 728
Latin America Utilities	1,904	1,765	-	-	1,904	1,765
North America Generation	372	391	-	-	372	391
North America Utilities	289	288	-	-	289	288
Europe Generation	400	322	(1)	-	399	322
Asia Generation	115	176	-	-	115	176
Corp/Other & eliminations	53	(5)	252	255	305	250
Total Revenue	$ 4,264	$ 3,920	$ -	$ -	$ 4,264	$ 3,920

	Total Adjusted Gross Margin 2011	Total Adjusted Gross Margin 2010	Intersegment 2011	Intersegment 2010	External Adjusted Gross Margin 2011	External Adjusted Gross Margin 2010
	(in millions)					
Adjusted Gross Margin						
Latin America Generation	$ 470	$ 394	$ (239)	$ (251)	$ 231	$ 143
Latin America Utilities	341	299	245	255	586	554
North America Generation	126	138	4	4	130	142
North America Utilities	90	113	-	-	90	113
Europe Generation	106	125	1	1	107	126
Asia Generation	45	69	1	1	46	70
Corp/Other & eliminations	39	9	(12)	(10)	27	(1)
Reconciliation to Income from Continuing Operations before Taxes						
Depreciation and amortization					(296)	(266)
Interest expense					(351)	(381)
Interest income					95	108
Other expense					(17)	(12)
Other income					16	9
Gain on sale of investments					6	-
Foreign currency transaction gains (losses) on net monetary position					33	(51)
Income from continuing operations before taxes and equity in earnings of affiliates					$ 703	$ 554

Assets by segment as of March 31, 2011 and December 31, 2010 were as follows:

	Total Assets March 31, 2011	Total Assets December 31, 2010
	(in millions)	
Assets		
Latin America Generation	$ 10,569	$ 10,373
Latin America Utilities	10,131	10,081
North America Generation	4,512	4,681
North America Utilities	3,174	3,139
Europe Generation	4,510	4,178
Asia Generation	1,693	1,762
Discontinued businesses	228	258

Corp/Other & eliminations		5,683		6,039
Total Assets	$	40,500	$	40,511

13. OTHER INCOME (EXPENSE)

Other income was $16 million and $9 million for the three months ended March 31, 2011 and 2010, respectively, and generally includes gains on asset sales and extinguishments of liabilities, favorable judgments on contingencies and income from miscellaneous transactions.

Other expense for the three months ended March 31, 2011 and 2010 of $17 million and $12 million, respectively, was primarily comprised of losses on disposal of assets at Eletropaulo. Other expense generally includes losses on asset sales, losses on the extinguishment of debt, contingencies and losses from miscellaneous transactions.

14. DISCONTINUED OPERATIONS AND HELD FOR SALE BUSINESSES

Discontinued operations includes the results of the following generation businesses: Eastern Energy including Cayuga, Greenidge, Somerset and Westover, in New York (held for sale in March 2011); Borsod and Tiszapalkonya, in Hungary (held for sale in March 2011); Ras Laffan, in Qatar (sold in October 2010); Barka, in Oman (sold in August 2010); and Lal Pir and Pak Gen, in Pakistan (sold in June 2010).

For the three months ended March 31, 2010, the Company recognized impairments of $13 million ($7 million, net of tax and noncontrolling interests) to reflect the change in the carrying value of net assets of Lal Pir and Pak Gen subsequent to meeting the held for sale criteria as of December 31, 2009. The carrying value of net assets was compared to the agreed upon sales proceeds of Lal Pir and Pak Gen, resulting in the impairment.

The following table summarizes the revenue, income from operations of discontinued businesses, income tax expense and impairment of discontinued operations for the three months ended March 31, 2011 and 2010:

	Three Months Ended March 31,	
	2011	2010
	(in millions)	
Revenue	$ 89	$ 378
Income (loss) from operations of discontinued businesses	$ (18)	$ 45
Income tax benefit (expense)	6	(11)
Income (loss) from operations of discontinued businesses, net of tax	$ (12)	$ 34
Impairment of discontinued operations	$ -	$ (13)

15. EARNINGS PER SHARE

Basic and diluted earnings per share are based on the weighted average number of shares of common stock and potential common stock outstanding during the period. Potential common stock, for purposes of determining diluted earnings per share, includes the effects of dilutive restricted stock units, stock options and convertible securities. The effect of such potential common stock is computed using the treasury stock method or the if-converted method, as applicable.

The following table presents a reconciliation of the numerator and denominator of the basic and diluted earnings per share computation for income from continuing operations for the three months ended March 31, 2011 and 2010. In the table below income represents the numerator (in millions) and weighted-average shares represent the denominator (in millions):

	Three Months Ended March 31, 2011			2010		
	Income	**Shares**	**$ per Share**	**Income**	**Shares**	**$ per Share**
BASIC EARNINGS PER SHARE						
Income from continuing operations attributable to The AES Corporation common stockholders	$ 236	787	$ 0.30	$ 170	695	$ 0.24
EFFECT OF DILUTIVE SECURITIES						
Stock options	-	2	-	-	2	-
Restricted stock units	-	3	-	-	4	-
DILUTED EARNINGS PER SHARE	$ 236	792	$ 0.30	$ 170	701	$ 0.24

There were approximately 16,253,344 and 16,446,542 additional options outstanding at March 31, 2011 and 2010, respectively, that could potentially dilute basic earnings per share in the future. Those options were not included in the computation of diluted earnings per share because the exercise price exceeded the average market price during the related periods. For the three months ended March 31, 2011 and 2010, all convertible debentures were omitted from the computation of diluted earnings per share because they were anti-dilutive. During the three months ended March 31, 2011, 1,060,839 shares of common stock were issued under the Company s profit sharing plan and 218,800 shares of common stock were issued upon the exercise of stock options.

16. SUBSEQUENT EVENTS

Subsequent to March 31, 2011, the Company continued to repurchase stock under the stock repurchase program announced on July 7, 2010. The Company has repurchased 2,774,700 shares at a cost of $36 million subsequent to March 31, 2011, bringing the cumulative total through May 6, 2011 to 16,100,536 shares at a total cost of $198 million (average price of $12.29 per share including commissions). As of May 6, 2011, $302 million of the $500 million authorized remained available under the stock repurchase program. For additional information, see Note 11 *Equity*.

On April 20, 2011, the Company announced the execution of a definitive agreement (the Merger Agreement) with DPL Inc.(DPL), the parent company of Dayton Power & Light Company, a utility company based in Ohio. Under the terms of the agreement, AES has agreed to acquire DPL for an enterprise value of $4.7 billion, consisting of cash proceeds of $3.5 billion and the assumption of net debt of approximately $1.2 billion. Through its operating subsidiaries DP&L and DPL Energy Resources, DPL serves over 500,000 customers in West Central Ohio. Additionally, DPL operates over 3,800 MW of power generation facilities and provides competitive retail energy services to industrial and commercial customers. Upon closing of the transaction, DPL will become a wholly-owned subsidiary of AES.

Simultaneously with the execution of the Merger Agreement, the Company entered into commitment letters (the Commitment Letters) with Bank of America, N.A. and Merrill Lynch, Pierce, Fenner & Smith Incorporated (together, the Bridge Providers). The Commitment Letters provide that, subject to certain customary terms and conditions, the Bridge Providers will provide senior unsecured bridge loans in an aggregate principal amount of $3.3 billion (the Bridge Facilities) to backstop a portion of the Company s payment obligations upon consummation of the merger. The Company will pay certain customary fees and expenses in connection therewith. To the extent funded, the agreement governing the Bridge Facilities will subject the

Company to customary terms and covenants and will be subject to customary events of default. Permanent financing is expected to include a combination of non-recourse debt, the issuance of corporate debt at AES and cash on hand.

The Merger Agreement contains certain termination rights and conditions precedent. The Merger Agreement contains certain termination rights for DPL and AES and further provides that, if DPL terminates the Merger Agreement prior to DPL shareholder approval in order to pursue a superior offer, DPL is required to pay AES a termination fee of $106 million (or $53 million if DPL terminates the Merger Agreement within 45 days after its execution, in order to pursue a superior offer with a party that presents its offer within 30 days of the execution of the Merger Agreement). The consummation of the transaction is subject to approval of DPL shareholders, the Public Utilities Commission of Ohio, FERC, and antitrust review under the Hart-Scott-Rodino Act. Approvals are expected to be completed within six to nine months, although there can be no assurance that such approvals will be obtained. The transaction is also subject to certain other closing conditions. After the announcement of the transaction, certain lawsuits were filed seeking to enjoin the merger and/or seek unspecified monetary damages, some of which name AES as a defendant. The Company does not believe the suits will be successful; however, there can be no assurances regarding the outcome of the litigation.

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

In this Quarterly Report on Form 10-Q (Form 10-Q), the terms AES, the Company, us, or we refer to the consolidated entity and all of its subsidiaries and affiliates, collectively. The term The AES Corporation or the Parent Company refers only to the parent, publicly-held holding company, The AES Corporation, excluding its subsidiaries and affiliates.

The condensed consolidated financial statements included in Item 1. Financial Statements of this Form 10-Q and the discussions contained herein should be read in conjunction with our 2010 Form 10-K.

FORWARD-LOOKING INFORMATION

The following discussion may contain forward-looking statements regarding us, our business, prospects and our results of operations that are subject to certain risks and uncertainties posed by many factors and events that could cause our actual business, prospects and results of operations to differ materially from those that may be anticipated by such forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those described in Item 1A. Risk Factors of our 2010 Form 10-K filed on February 25, 2011 and this Form 10-Q, and our ability to successfully consummate and integrate the proposed DPL acquisition described elsewhere in this Quarterly Report. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this report. We undertake no obligation to revise any forward-looking statements in order to reflect events or circumstances that may subsequently arise. If we do update one or more forward-looking statements, no inference should be drawn that we will make additional updates with respect to those or other forward-looking statements. Readers are urged to carefully review and consider the various disclosures made by us in this report and in our other reports filed with the SEC that advise of the risks and factors that may affect our business.

Overview of Our Business

We are a global power company. We operate two primary lines of business. The first is our Generation business, where we own and/or operate power plants to generate and sell power to wholesale customers such as utilities, other intermediaries and certain end-users. The second is our Utilities business, where we own and/or operate utilities which distribute, transmit and sell electricity to end-user customers in the residential, commercial, industrial and governmental sectors within a defined service area and in certain circumstances, sell electricity on the wholesale market. For the three months ended March 31, 2011 our Generation and Utilities businesses comprised approximately 43% and 57% of our consolidated revenue, respectively.

We are also continuing to expand our wind generation business and are pursuing additional opportunities in the renewable business including solar and climate solutions, which develops and invests in projects that generate greenhouse gas offsets and/or other renewable projects. These initiatives are not material contributors to our operating results, but we believe that certain of these initiatives may become material in the future. For additional information regarding our business, see Item 1. Business of the 2010 Form 10-K.

Our Organization and Segments. The management reporting structure is organized along our two lines of business (Generation and Utilities) and three regions: (1) Latin America & Africa; (2) North America; and (3) Europe, Middle East & Asia (collectively EMEA), each managed by a regional president. The financial reporting segment structure uses the Company s management reporting structure as its foundation and reflects how the Company manages the business internally. The Company applied the segment reporting accounting guidance, which provides certain quantitative thresholds and aggregation criteria, and concluded that it has the following six reportable segments:

- Latin America Generation;
- Latin America Utilities;

- North America Generation;
- North America Utilities;
- Europe Generation;
- Asia Generation.

Corporate and Other. The Company s Europe Utilities, Africa Utilities, Africa Generation, Wind Generation and Climate Solutions operating segments are reported within Corporate and Other because they do not meet the criteria to allow for aggregation with another operating segment or the quantitative thresholds that would require separate disclosure under segment reporting accounting guidance. None of these operating segments are currently material to our financial statement presentation of reportable segments, individually or in the aggregate. Corporate and Other also includes costs related to corporate overhead which are not directly associated with the operations of our six reportable segments and other intercompany charges such as self-insurance premiums which are fully eliminated in consolidation.

Components of Revenue and Cost of Sales. Revenue includes revenue earned from the sale of energy from our utilities and the generation of energy from our generation plants, which are classified as regulated and unregulated on the condensed consolidated statement of operations, respectively. Cost of sales includes costs incurred directly by the businesses in the ordinary course of business. Examples include electricity and fuel purchases, maintenance, operations, non-income taxes and bad debt expense and recoveries as well as depreciation, general and administrative and support costs, including employee-related costs, that are directly associated with the operations of a particular business. Cost of sales also includes the gains or losses on derivatives (including embedded derivatives other than foreign currency embedded derivatives) associated with the purchase of electricity or fuel.

Key Drivers of Our Results of Operations. Our Generation and Utilities businesses are distinguished by the nature of their customers, operational differences, cost structure, regulatory environment and risk exposure. As a result, each line of business has slightly different drivers which affect operating results. Performance drivers for our Generation businesses include, among other things, plant reliability and efficiency, power prices, volume, management of fixed and variable operating costs, management of working capital including collection of receivables, and the extent to which our plants have hedged their exposure to currency and commodities such as fuel. For our Generation businesses which sell power under short-term contracts or in the spot market, the most crucial factors are the current market price of electricity and the marginal costs of production. Growth in our Generation business is largely tied to securing new PPAs, expanding capacity in our existing facilities and building or acquiring new power plants. Performance drivers for our Utilities businesses include, but are not limited to, reliability of service; management of working capital, including collection of receivables; negotiation of tariff adjustments; compliance with extensive regulatory requirements; management of pension assets; and in developing countries, reduction of commercial and technical losses. The operating results of our Utilities businesses are sensitive to changes in inflation, economic growth and weather conditions in areas in which they operate. In addition to these drivers, as explained below, the Company also has exposure to currency exchange rate fluctuations.

One of the key factors which affect our Generation business is our ability to enter into contracts for the sale of electricity and the purchase of fuel used to produce that electricity. Long-term contracts are intended to reduce the exposure to volatility associated with fuel prices in the market and the price of electricity by fixing the revenue and costs for these businesses. The majority of the electricity produced by our Generation businesses is sold under long-term contracts, or PPAs, to wholesale customers. In turn, most of these businesses enter into long-term fuel supply contracts or fuel tolling arrangements where the customer assumes full responsibility for purchasing and supplying the fuel to the power plant. While these long-term contractual agreements reduce exposure to volatility in the market price for electricity and fuel, the predictability of operating results and cash flows vary by business based on the extent to which a facility s generation capacity and fuel requirements are contracted and the negotiated terms of these agreements. Entering into these contracts exposes us to counterparty credit risk. For further discussion of these risks, see *Supplier and/or customer concentration may expose the Company to significant financial credit or performance risks.* in Item 1A. Risk Factors of the 2010 Form 10-K.

When fuel costs increase, many of our businesses are able to pass these costs on to their customers. Generation businesses with long-term contracts in place do this by including fuel pass-through or fuel indexing arrangements in their contracts. Utilities businesses can pass costs on to their customers through increases in current or future tariff rates. Therefore, in a rising fuel cost environment, the increased fuel costs for these businesses often result in an increase in revenue to the extent these costs can be passed through (though not necessarily on a one-for-one basis). Conversely, in a declining fuel cost environment, the decreased fuel costs can result in a decrease in revenue. Increases or decreases in revenue at these businesses that have the ability to pass through costs to the customer have a corresponding impact on cost of sales, to the extent the costs can be passed through, resulting in a limited impact on gross margin, if any. Although these circumstances may not have a large impact on gross margin, they can significantly affect gross margin as a percentage of revenue. As a result, gross margin as a percentage of revenue is a less relevant measure when evaluating our operating performance. To the extent our businesses are unable to pass through fuel cost increases to their customers, gross margin may be adversely affected.

Global diversification also helps us to mitigate risk. Our presence in mature markets helps mitigate the exposure associated with our businesses in emerging markets. Additionally, our portfolio employs a broad range of fuels, including coal, gas, fuel oil, water (hydroelectric power), wind and solar, which reduces the risks associated with dependence on any one fuel source. However, to the extent the mix of fuel sources enabling our generation capabilities in any one market is not diversified, the spread in costs of different fuels may also influence the operating performance and the ability of our subsidiaries to compete within that market. For example, in a market where gas prices fall to a low level compared to coal prices, power prices may be set by low gas prices which can affect the profitability of our coal plants in that market. In certain cases, we may attempt to hedge fuel prices to manage this risk, but there can be no assurance that these strategies will be effective.

We also attempt to limit risk by hedging much of our interest rate and commodity risk, and by matching the currency of most of our subsidiary debt to the revenue of the underlying business. However, we only hedge a portion of our currency and commodity risks, and our businesses are still subject to these risks, as further described in Item 1A. Risk Factors of the 2010 Form 10-K, *We may not be adequately hedged against our exposure to changes in commodity prices or interest rates*. Commodity and power price volatility could continue to impact our financial metrics to the extent this volatility is not hedged. For a discussion of our sensitivities to commodity, currency and interest rate risk, see Item 3. Quantitative and Qualitative Disclosures About Market Risk in this Form 10-Q.

Due to our global presence, the Company has significant exposure to foreign currency fluctuations. The exposure is primarily associated with the impact of the translation of our foreign subsidiaries operating results from their local currency to U.S. dollars that is required for the preparation of our consolidated financial statements. Additionally, there is a risk of transaction exposure when an entity enters into transactions, including debt agreements, in currencies other than their functional currency. These risks are further described in Item 1A. Risk Factors of the 2010 Form 10-K, *Our financial position and results of operations may fluctuate significantly due to fluctuations in currency exchange rates experienced at our foreign operations*. In the three months ended March 31, 2011, changes in foreign currency exchange rates have had a significant impact on our operating results. If the current foreign currency exchange rate volatility continues, our gross margin and other financial metrics could be affected.

Another key driver of our results is our ability to bring new businesses into commercial operations successfully. We currently have approximately 2,038 MW of projects under construction in ten countries. Our prospects for increases in operating results and cash flows are dependent upon successful completion of these projects on time and within budget. However, as disclosed in Item 1A. Risk Factors of the 2010 Form 10-K, *Our business is subject to substantial development uncertainties*, construction is subject to a number of risks, including risks associated with site identification, financing and permitting and our ability to meet construction deadlines. Delays or the inability to complete projects and commence commercial operations can result in increased costs, impairment of assets and other challenges involving partners and counterparties to our construction agreements, PPAs and other agreements.

Our gross margin is also impacted by the fact that in each country in which we conduct business, we are subject to extensive and complex governmental regulations such as regulations governing the generation and distribution of electricity, and environmental regulations which affect most aspects of our business. Regulations differ on a country by country basis (and even at the state and local municipality levels) and are based upon the type of business we operate in a particular country, and affect many aspects of our operations and development projects.

Our ability to negotiate tariffs, enter into long-term contracts, pass through costs related to capital expenditures and otherwise navigate these regulations can have an impact on our revenue, costs and gross margin. Environmental and land use regulations, including existing and proposed regulation of greenhouse gas (GHG) emissions, could substantially increase our capital expenditures or other compliance costs, which could in turn have a material adverse affect on our business and results of operations. For a further discussion of the Regulatory Environment, see Note 9 *Contingencies and Commitments Environmental*, included in Item 1. Financial Statements of this Form 10-Q and Item 1. Business *Regulatory Matters Environmental and Land Use Regulations* and Item 1A. Risk Factors *Risks Associated with Government Regulation and Laws* of the 2010 Form 10-K.

Key Drivers of Results in the Three Months Ended March 31, 2011

During the three months ended March 31, 2011, the Company s gross margin increased $55 million and net income attributable to The AES Corporation increased $37 million, while net cash from operating activities decreased $163 million compared to the same period in 2010.

During the three months ended March 31, 2011, Gener, our generation business in Chile saw improvements over the prior year due to combined impact of higher demand given the lower dispatch in 2010 as a result of the Chilean earthquake in February 2010, higher generation at the Electrica Santiago plant running on liquefied natural gas and higher contract and spot prices due to low hydrology. These favorable results were slightly offset by the unfavorable impact at Kilroot, in Northern Ireland as a result of the PPA that was canceled in November 2010, which caused the plant to sell exclusively in the merchant market.

In 2011, we expect to face continued challenges in our business, including the impact of fluctuating foreign exchange rates on our operations. The components of the 2011 tariff reset in Brazil and its potential impact on our Brazilian utility, Eletropaulo, are uncertain at this time and we expect continued challenges in our merchant businesses, such as Kilroot in Northern Ireland. Throughout 2011, comparisons to 2010 will remain challenging for Masinloc, our coal-fired generation facility in the Philippines. In 2010, Masinloc benefited from high spot prices and supply shortages in the Philippines power market. We do not expect these trends in the Philippines to continue in 2011. Additionally, the Company identified damage to a tunnel at a hydroelectric plant in Panama which will cause the plant to be offline for the remainder of 2011. Until the ultimate disposition of Eastern Energy in New York, which is currently classified as held for sale, the Company continues to see the effects of relatively lower gas prices and a decline in power prices relative to coal. These impacts are only partially hedged through mid-2011. However, management expects that improved operating performance at certain businesses and growth from newly acquired businesses and businesses expected to commence operations in 2011, may lessen or offset the impact of the challenges described above. However, if these favorable effects do not occur, or if the challenges described above and elsewhere in this section impact us more significantly than we currently anticipate, or if volatile foreign currencies and commodities move unfavorably, then these adverse factors (or other adverse factors unknown to us) may impact our gross margin and net income attributable to The AES Corporation.

The following briefly describes the key changes in our reported revenue, gross margin, net income attributable to The AES Corporation, diluted earnings per share from continuing operations, Adjusted Earnings per Share (a non-GAAP measure) and net cash provided by operating activities for the three months ended March 31, 2011 compared to three months ended March 31, 2010 and should be read in conjunction with our *Consolidated Results of Operations* discussion below.

Performance Highlights

	Three Months Ended March 31,		
	2011	2010	% Change
	(in millions, except per share amounts)		
Revenue	$ 4,264	$ 3,920	9%
Gross Margin	$ 1,016	$ 961	6%
Net Income Attributable to The AES Corporation	$ 224	$ 187	20%
Diluted Earnings per Share from Continuing Operations	$ 0.30	$ 0.24	25%
Adjusted Earnings Per Share (a non-GAAP measure)(1)	$ 0.22	$ 0.28	-21%
Net Cash Provided by Operating Activities	$ 505	$ 668	-24%

(1) See reconciliation and definition below under Non-GAAP Measure.

Revenue increased $344 million, or 9%, to $4.3 billion in the three months ended March 31, 2011 compared with $3.9 billion in the three months ended March 31, 2010. Key drivers of the increase included:

- the favorable impact of foreign currency of $155 million;
- increased rate and volume at our generation businesses at Gener, in Chile, and in Argentina;
- the impact of the Company s new business, Ballylumford, in Northern Ireland, acquired in August 2010; and
- increased volume at our Brazilian utilities, driven by increased market demand.

These increases were partially offset by:

- lower rates at our utility businesses in Latin America;
- a decrease in volume at Kelanitissa, in Sri Lanka; and
- lower rates and volume at Kilroot, in Northern Ireland.

Gross margin increased $55 million, or 6%, to $1.0 billion in the three months ended March 31, 2011 compared with $961 million in the three months ended March 31, 2010. Key drivers of the increase included:

the favorable impact of foreign currency of $36 million;

an increase in rate and volume at Gener;

increased market demand at our Brazilian utilities; and

- the impact of Ballylumford, acquired in August 2010.

These increases were partially offset by:

- an increase in global fixed costs;
- lower rates and volume at Kilroot;
- lower rates at our utility businesses in Latin America;
- an increase in outages, primarily in Panama; and
- lower volume at Masinloc, in the Philippines.

Net income attributable to The AES Corporation increased $37 million, or 20%, to $224 million in the three months ended March 31, 2011 compared with $187 million in the three months ended March 31, 2010. Key drivers of the increase included:

- the increase in gross margin as described above;
- lower interest expense due to retirement of Parent company debt;
- foreign currency transaction gains due to an increase in foreign currency denominated notes receivable and cash balances.

These increases were partially offset by:

- Higher income taxes due to an increase in income offset by a decrease in the effective tax rate.

Net cash provided by operating activities decreased $163 million, or 24%, to $505 million in the three months ended March 31, 2011 compared with $668 million in the three months ended March 31, 2010. Please refer to *Consolidated Cash Flows Operating Activities* for further discussion.

Non-GAAP Measure

We define adjusted earnings per share (Adjusted EPS) as diluted earnings per share from continuing operations excluding gains or losses of the consolidated entity due to (a) mark-to-market amounts related to derivative transactions, (b) unrealized foreign currency gains or losses, (c) significant gains or losses due to dispositions and acquisitions of business interests, (d) significant losses due to impairments, and (e) costs due to the early retirement of debt. The GAAP measure most comparable to Adjusted EPS is diluted earnings per share from continuing operations. AES believes that Adjusted EPS better reflects the underlying business performance of the Company and is considered in the Company s internal evaluation of financial performance. Factors in this determination include the variability due to mark-to-market gains or losses related to derivative transactions, currency gains or losses, losses due to impairments and strategic decisions to dispose or acquire business interests or retire debt, which affect results in a given period or periods. Adjusted EPS should not be construed as an alternative to diluted earnings per share from continuing operations, which is determined in accordance with GAAP.

	Three Months Ended March 31,

		2011		2010
Reconciliation of Adjusted Earnings Per Share				
Diluted earnings per share from continuing operations	**$**	**0.30**	**$**	**0.24**
Derivative mark-to-market (gains)/losses[1]		(0.01)		0.01
Currency transaction (gains)/losses[2]		(0.07)		0.03
Adjusted earnings per share	**$**	**0.22**	**$**	**0.28**

(1) Derivative mark-to-market (gains)/losses were net of income tax per share of $0.00 and $0.01 in the three months ended March 31, 2011 and 2010, respectively.

(2) Unrealized foreign currency transaction (gains)/losses were net of income tax per share of $(0.01) and $0.00 in the three months ended March 31, 2011 and 2010, respectively.

Management s Priorities

Management continues to focus on the following priorities:

- Resolving conditions precedent and obtaining permanent financing to allow us to close the acquisition of DPL, Inc.;
- Continued execution of our balanced capital allocation strategy, including a review of new acquisitions or development projects;
- Achieving commercial operation at Maritza in Bulgaria. At the end of 2010, the Company experienced certain commissioning delays, as further described in *Key Trends and Uncertainties Development* below;
- Strategic portfolio management of existing projects including restructuring and/or potential sales of certain North America generation subsidiaries, such as Eastern Energy;
- Improvement of operations in the existing portfolio;
- Achieve cost savings through the alignment of overhead costs with business requirements, systems automation and optimal allocation of business development spending;
- Repair of the Esti hydro tunnel in Panama, as further described in *Key Trends and Uncertainties Operations* below;
- Completion of an approximately 2,038 MW construction program on time and within budget; and
- Integration of new projects. During the three months ended March 31, 2011, the following projects commenced commercial operations:

Project	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)
Kumkoy[1]	Turkey	Hydro	18	51%
Kalipetrovo[2]	Bulgaria	Solar	4	50%
Ugento[2]	Italy	Solar	3	50%

(1) Joint Venture with I.C. Energy.

(2) AES Solar Energy Ltd. is a Joint Venture with Riverstone Holdings.

Key Trends and Uncertainties

Our operations continue to face many risks as discussed in Item 1A. Risk Factors of the 2010 Form 10-K. Some of these challenges are also described above in *Key Drivers of Results in the Three Months Ended March 31, 2011*. We continue to monitor our operations and address challenges as they arise.

Development. The Company has successfully acquired and completed construction of a number of projects, totaling approximately 25 MW, including completion of construction of a number of projects in Italy, Bulgaria and Turkey. However, as discussed in Item 1A. Risk Factors *Our business is subject to substantial development uncertainties* of the 2010 Form 10-K, our development projects are subject to uncertainties. Certain delays have occurred at the 670 MW Maritza coal-fired project in Bulgaria, and the project had not begun commercial operations. As a result of these delays the project debt is in default and the Company is working with its lenders to resolve the default. In addition, the Company is in litigation with the contractor regarding the cause of delays. The EPC contract was terminated for cause by the Company during the quarter. At this time, we believe that Maritza will commence commercial operations for at least some of the project s capacity by the second half of 2011. However, commencement of commercial operations could be delayed beyond this time frame. There can be no assurance that Maritza will achieve commercial operations, in whole, or in part, by the second half of 2011, resolve the default with the lenders or prevail in the litigation referenced above, which could result in the loss of some or all of our investment or require additional funding for the project. Any of these events could have a material adverse effect on the Company s operating results or financial position.

Operations. Beginning in August 2010 the Esti power plant, a 120 MW run-of-river hydroelectric power plant in Panama, experienced a reduction in power generation. Following an inspection of its tunnel infrastructure in October 2010, which indicated damage, the plant was taken off line. A significant repair of the Esti tunnel and additional surrounding support structures was deemed necessary to allow the plant to continue operation and to prevent future potential damage to the tunnel. AES Panama is partially covered for business interruption losses and property damage under existing insurance programs. AES Panama launched a bidding process for the repair work in February 2011. The current project plan estimates that the Esti plant will be back in operation by the second quarter of 2012.

Global Economic Conditions. During the past few years, economic conditions in some countries where our subsidiaries conduct business have deteriorated. Although the economic conditions in several of these countries have improved in recent months, our businesses could be impacted in the event these recent trends do not continue.

Our business or results of operations could be impacted if we or our subsidiaries are unable to access the capital markets on favorable terms or at all, are unable to raise funds through the sale of assets or are otherwise unable to finance or refinance our activities. The Company has committed financing in place for the DPL Inc. acquisition, but intends to be opportunistic and obtain permanent financing on better terms. The Company could also be adversely affected if capital market disruptions result in increased borrowing costs (including with respect to interest payments on the Company s or our subsidiaries variable rate debt) or if commodity prices affect the profitability of our plants or their ability to continue operations. Additionally, the Company could be adversely affected if general economic or political conditions in the markets where our subsidiaries operate deteriorate, resulting in a reduction in cash flow from operations, a reduction in the availability and/or an increase in the cost of capital, or if the value of our assets remain depressed or decline further. Any of the foregoing events or a combination thereof could have a material impact on the Company, its results of operations, liquidity, financial covenants, and/or its credit rating.

Our subsidiaries are subject to credit risk, which includes risk related to the ability of counterparties (such as parties to our PPAs, fuel supply agreements, hedging agreements and other contractual arrangements) to deliver contracted commodities or services at the contracted price or to satisfy their financial or other contractual obligations. The Company has not suffered any material effects related to its counterparties during the three months ended March 31, 2011. However, if macroeconomic conditions impact our counterparties, they may be unable to meet their commitments which could result in the loss of favorable contractual positions, which could have a material impact on our business.

In addition, during the past year, certain European countries have faced a sovereign debt crisis and it is possible that other nations could be affected. This crisis has resulted in an increased risk of default by governments and the implementation of austerity measures in certain countries. If the crisis continues, worsens, or spreads, there could be a material adverse impact on the Company. Our businesses may be impacted if they are unable to access the capital markets, face increased taxes or labor costs, or if governments fail to fulfill their obligations to us or adopt austerity measures which adversely impact our projects. In addition, as discussed in Item 1A. Risk Factors *Our renewable energy projects and other initiatives face considerable uncertainties including development, operational and regulatory challenges* of the 2010 Form 10-K. Our renewables businesses are dependent on favorable regulatory incentives, including subsidies, which are provided by sovereign governments. If these subsidies or other incentives are reduced or repealed, or sovereign governments are unable or unwilling to fulfill their commitments or maintain favorable regulatory incentives for renewables, in whole or in part, this could impact the ability of the affected businesses to continue to grow their operations. For example, the Spanish government recently issued a decree which limits the feed-in-tariff and number of photovoltaic hours eligible for the feed-in-tariff and the Italian government recently published a decree which restricts the size of projects on agricultural land and ends the current feed-in-tariff for projects not interconnected by May 31, 2011. On May 5, 2011, the Italian government established the new feed-in-tariff resulting in an approximate 30% reduction to the current tariff. These decrees will adversely impact AES Solar Energy Ltd. in Spain and Italy. For further information on the Spain decree see Item 1. Regulatory Spain of the 2010 Form 10-K. In addition, any of the foregoing could also impact contractual counterparties of our subsidiaries in core power or renewables. If such counterparties are adversely impacted, then they may be unable to meet their commitments to our subsidiaries. For further information on the importance of long-term contracts and our counterparty credit risk, see Item 1A. Risk Factors *We may not be able to enter into long-term contracts, which reduce volatility in our results of operations* of the 2010 Form 10-K. As a result of any of the foregoing events, we may have to provide loans or equity to support affected businesses or projects, restructure them, write down their value and/or face the possibility that these projects cannot continue operations or provide returns consistent with our expectations, any of which could have a material impact on the Company. The Company s investment in AES Solar Energy Ltd., whose primary operations are in Europe, was $271 million at March 31, 2011. During the three months ended March 31, 2011, in connection with the Italian decree, AES Solar Energy Ltd. recognized an impairment of $6 million on its assets, of which AES share was $3 million. At this time, AES Solar Energy Ltd. is evaluating whether any potential indicators of impairment are present as a result of the newly established feed-in-tariff in Italy.

If global economic conditions worsen, it could also affect the rates we receive for the electricity we generate or transmit. Utility regulators or parties to our generation contracts may seek to lower our rates based on prevailing market conditions as PPAs, concession agreements or other contracts come up for renewal or reset. In addition, rising fuel and other costs coupled with contractual rate or tariff decreases could restrict our ability to operate profitably in a given market. Each of these factors, as well as those discussed above, could result in a decline in the value of our assets including those at the businesses we operate, our equity investments and projects under development and could result in asset impairments that could be material to our operations. We continue to monitor our projects and businesses.

Impairments.

Long-lived assets. The global economic conditions and other adverse factors discussed above heighten the risk of a significant asset impairment. Examples of conditions that could be indicative of impairment which would require us to evaluate the recovery of a long-lived asset or asset group include:

- current period operating or cash flow losses combined with a history of operating or cash flow losses or a projection that demonstrates continuing losses associated with the use of a long-lived asset group;

- a significant adverse change in legal factors, including changes in environmental or other regulations or in the business climate that could affect the value of a long-lived asset group, including an adverse action or assessment by a regulator; and

- a significant adverse change in the extent or manner in which a long-lived asset group is being used or in its physical condition.

Goodwill. The Company seeks business acquisitions as one of its growth strategies. We have achieved significant growth in the past as a result of several business acquisitions, which also resulted in the recognition of goodwill. As noted in Item 1A. Risk Factors of the 2010 Form 10-K, there is always a risk that *Our acquisitions may not perform as expected.* The benefits of goodwill are typically realized through the future operating results of an acquired business. Management believes that the recoverability of goodwill is positively correlated with the economic environments in which our acquired businesses operate and a severe economic downturn could negatively impact the recoverability of goodwill. Also, the evolving environmental regulations, including GHG regulations, around the globe continue to increase the operating costs of our generation businesses. In extreme situations, the environmental regulations could even make a once profitable business uneconomical. In addition, most of our generation businesses have a finite life and as the acquired businesses reach the end of their finite lives, the carrying amount of goodwill is gradually recovered through their periodic operating results. The accounting guidance, however, prohibits the systematic amortization of goodwill and rather requires an annual impairment evaluation. Thus, as some of our acquired businesses approach the end of their finite lives, they may incur goodwill impairment charges even if there are no discrete adverse changes in the economic environment.

In the fourth quarter of 2010, the Company completed its annual goodwill impairment evaluation and did not have any reporting units that were considered at risk. A reporting unit is considered at risk when its fair value is not higher than its carrying amount by more than 10%. While there were no potential impairment indicators that could result in the recognition of goodwill impairment for any reporting units, it is possible we may incur goodwill impairment on these reporting units in future years if any of the following events occur: a significant adverse change in business climate or legal factors, an adverse action or assessment by a regulator, a sale of assets at less than carrying amount, unanticipated competition, a loss of key personnel, an acquisition not performing as expected, changing environmental regulations that significantly increase the cost of doing business, or a business reaches the end of its finite life. The likelihood of the occurrence of these events may increase because of the challenging global macroeconomic conditions including those experienced recently that resulted in the recognition of goodwill impairment in 2009 and 2010.

Regulatory Environment. The Company is subject to numerous environmental laws and regulations in the jurisdictions in which it operates. The Company expenses environmental regulation compliance costs as incurred unless the underlying expenditure qualifies for capitalization under its property, plant and equipment policies. The Company faces certain risks and uncertainties related to these environmental laws and regulations, including existing and potential GHG legislation or regulations, and actual or potential laws and regulations pertaining to water discharges, waste management (including disposal of coal combustion byproducts), and certain air emissions, such as SO_2, NO_x, particulate matter and mercury. Such risks and uncertainties could result in increased capital expenditures or other compliance costs which could have a material adverse effect on certain of our U.S. or international subsidiaries and our consolidated results of operations. For further information about these risks, see Item 1A. Risk Factors, *Our businesses are subject to stringent environmental laws and regulations*, *Our businesses are subject to enforcement initiatives from environmental regulatory agencies*, and *Regulators, politicians, non-governmental organizations and other private parties have expressed concern about greenhouse gas, or GHG, emissions and the potential risks associated with climate change and are taking actions which could have a material adverse impact on our consolidated results of operations, financial condition and cash flows* set forth in the Company s Form 10-K for the year ended December 31, 2010.

Legislation and Regulation of GHG Emissions.

Currently, in the United States there is no Federal legislation establishing mandatory GHG emissions reduction programs (including CO_2) affecting the electric power generation facilities of the Company s subsidiaries. There are numerous state programs regulating GHG emissions from electric power generation facilities and there is a possibility that federal GHG legislation will be enacted within the next several years. Further, the United States Environmental Protection Agency (EPA) has adopted regulations pertaining to GHG emissions and has announced its intention to propose new regulations for electric generating units under Section 111 of the United States Clean Air Act (CAA).

Potential U.S. Federal GHG Legislation. As noted in the Company s 2010 Form 10-K, federal legislation passed the U.S. House of Representatives in 2009 that, if adopted, would have imposed a nationwide cap-and-trade program to reduce GHG emissions. This legislation was never signed into law, and is no longer under consideration. In the U.S. Senate, several different draft bills pertaining to GHG legislation have been considered, including comprehensive GHG legislation similar to the legislation that passed the U.S. House of Representatives and more limited legislation focusing only on the utility and electric generation industry. It is uncertain whether any legislation pertaining to GHG emissions will be voted on and passed by the U.S. Senate and House of Representatives. If any such legislation is enacted into law, the impact could be material to the Company.

EPA GHG Regulation. As noted in the Company s 2010 Form 10-K, the EPA has promulgated regulations governing GHG emissions from automobiles under the CAA. The effect of EPA s regulation of GHG emissions from mobile sources is that certain provisions of the CAA will also apply to GHG emissions from existing stationary sources, including many U.S. power plants. In particular, beginning January 2, 2011, construction of new stationary sources and modifications to existing stationary sources that result in increased GHG emissions became subject to permitting requirements under the prevention of significant deterioration (PSD) program of the CAA. The PSD program, as currently applicable to GHG emissions, requires sources that emit above a certain threshold of GHGs to obtain PSD permits prior to commencement of new construction or modifications to existing facilities. In addition, major sources of GHG emissions may be required to amend, or obtain new, Title V air permits under the CAA to reflect any new applicable GHG emissions requirements for new construction or for modifications to existing facilities.

The EPA promulgated a final rule on June 3, 2010, (the Tailoring Rule) that sets thresholds for GHG emissions that would trigger PSD permitting requirements. The Tailoring Rule, which became effective in January of 2011, provides that sources already subject to PSD permitting requirements need to install Best Available Control Technology (BACT) for greenhouse gases if a proposed modification would result in the increase of more than 75,000 tons per year of GHG emissions. Also, under the Tailoring Rule, commencing in July of 2011, any new sources of GHG emissions that would emit over 100,000 tons per year of GHG emissions, in addition to any modification that would result in GHG emissions exceeding 75,000 tons per year, would require PSD review and be subject to related permitting requirements. The EPA anticipates that it will adjust downward the permitting thresholds of 100,000 tons and 75,000 tons for new sources and modifications, respectively, in future rulemaking actions. The Tailoring Rule substantially reduces the number of sources subject to PSD requirements for GHG emissions and the number of sources required to obtain Title V air permits, although new thermal power plants may still be subject to PSD and Title V requirements because annual GHG emissions from such plants typically far exceed the 100,000 ton threshold noted above. The 75,000 ton threshold for increased GHG emissions from modifications to existing sources may reduce the likelihood that future modifications to plants owned by some of our United States subsidiaries would trigger PSD requirements, although some projects that would expand capacity or electric output are likely to exceed this threshold, and in any such cases the capital expenditures necessary to comply with the PSD requirements could be significant.

In December 2010, the EPA entered into a settlement agreement with several states and environmental groups to resolve a petition for review challenging the EPA s new source performance standards (NSPS) rulemaking for electric utility steam generating units (EUSGUs) based on the NSPS s failure to address GHG emissions. Under the settlement agreement, the EPA has committed to propose GHG emissions standards for EUSGUs by July 26, 2011 and to finalize GHG emissions standards for EUSGUs by May 26, 2012. The NSPS will establish GHG emission standards for newly constructed and reconstructed EUSGUs. The NSPS also will establish guidelines regarding the best system for achieving further GHG emissions reductions from EUSGUs and, based on such guidelines, individual states will be required to submit plans to the EPA to establish GHG emission standards for existing EUSGUs within their states. It is impossible to estimate the impact and compliance cost associated with any future NSPS applicable to EUSGUs until such regulations are finalized. However, the compliance costs could have a material and adverse impact on our consolidated financial condition or results of operations.

Regional Greenhouse Gas Initiative. As noted in the Company s 2010 Form 10-K, to date, the primary regulation of GHG emissions affecting the Company s U.S. plants has been through the Regional Greenhouse Gas Initiative (RGGI). Under RGGI, ten Northeastern States have coordinated to establish rules that require reductions in CO_2 emissions from power plant operations within those states through a cap-and-trade program. States participating in RGGI in which our subsidiaries have generating facilities include Connecticut, Maryland, New York and New Jersey. Under RGGI, power plants must acquire one carbon allowance through auction or in the emission trading markets for each ton of CO_2 emitted. As noted in the Company s 2010 Form 10-K, we have estimated the costs to the Company of compliance with RGGI to be approximately $15 million for 2011.

International GHG Regulation. As noted in the Company s 2010 Form 10-K, the primary international agreement concerning GHG emissions is the Kyoto Protocol, which became effective on February 16, 2005 and requires the industrialized countries that have ratified it to significantly reduce their GHG emissions. The vast majority of the developing countries which have ratified the Kyoto Protocol have no GHG emissions reduction requirements. Many of the countries in which the Company s subsidiaries operate have no emissions reduction obligations under the Kyoto Protocol. In addition, of the 28 countries in which the Company s subsidiaries operate, all but one the United States (including Puerto Rico) have ratified the Kyoto Protocol. The Kyoto Protocol is currently expected to expire at the end of 2012, and countries have been unable to agree on a successor agreement. The next annual United Nations conference to develop a successor international agreement is scheduled for November 2011 in South Africa. It currently appears unlikely that a successor agreement will be reached at such conference; however, if a successor agreement is reached the impact could be material to the Company.

There is substantial uncertainty with respect to whether U.S. federal GHG legislation will be enacted into law, whether new country-specific GHG legislation will be adopted in countries in which our subsidiaries conduct business, and whether a new international agreement to succeed the Kyoto Protocol will be reached. There is additional uncertainty regarding the final provisions or implementation of any potential U.S. federal or foreign country GHG legislation, the EPA s rules regulating GHG emissions and any international agreement to succeed the Kyoto Protocol. In light of these uncertainties, the Company cannot accurately predict the impact on its consolidated results of operations or financial condition from potential U.S. federal or foreign country GHG legislation, the EPA s regulation of GHG emissions or any new international agreement on such emissions, or make a reasonable estimate of the potential costs to the Company associated with any such legislation, regulation or international agreement; however, the impact from any such legislation, regulation or international agreement could have a material adverse effect on certain of our U.S. or international subsidiaries and on the Company and its consolidated results of operations.

Other U.S. Air Emissions Regulations and Legislation

As noted in the Company s Form 10-K for the year ended December 31, 2010, the Company s subsidiaries in the United States are subject to the Clean Air Act (CAA) and various state laws and regulations that regulate emissions of air pollutants, including SO_2, NO_X, particulate matter (PM), mercury and other hazardous air pollutants (HAPs).

The EPA promulgated the Clean Air Interstate Rule (CAIR) on March 10, 2005, which required allowance surrender for SO_2 and NO_X emissions from existing power plants located in 28 eastern states and the District of Columbia. CAIR was subsequently challenged in federal court, and on July 11, 2008, the United States Court of Appeals for the D.C. Circuit issued an opinion striking down much of CAIR and remanding it to the EPA. In response to the D.C. Circuit s opinion, on July 6, 2010, the EPA issued a new proposed rule (the Clean Air Transport Rule) to replace CAIR. The final Clean Air Transport Rule (Transport Rule) is scheduled to be issued by July 2011. The Transport Rule would require significant additional reductions in SO_2 and NO_X emissions in 31 states and the District of Columbia starting in 2012, including several states where subsidiaries of the Company conduct business.

The Transport Rule contemplates three possible options for reducing SO_2 and NO_X emissions in the designated states. The EPA s preferred option contemplates a set limit or budget on SO_2 and NO_X emissions for each of the states, with limited interstate trading of emissions allowances and unlimited intrastate trading of SO_2 and NO_X emissions allowances. Affected power plants would receive emissions allowances based on the applicable state emissions budgets. The EPA s second option under the Transport Rule would establish emission budgets for each state, but only allow intrastate trading of emissions allowances. The final option would set emission rate limitations for each power plant, but would allow for some intrastate averaging of emission rates. Under any of the proposed options, additional pollution control technology may be required by some of our subsidiaries, and the cost of implementing any such technology could affect the financial condition or results of operations of these subsidiaries or the parent company. The EPA has received public comments on the Transport Rule, and such public comments will be considered by the EPA prior to promulgating a final rule.

As noted in the Company s 2010 Form 10-K, as a result of prior EPA determinations and the D.C. Circuit Court ruling, the EPA is obligated under Section 112 of the CAA to develop a rule requiring pollution controls for hazardous air pollutants, including mercury, hydrogen chloride, hydrogen fluoride, and nickel species from coal and oil-fired power plants. The EPA has entered into a consent decree under which it is obligated to finalize the rule by November 2011. In connection with such rule, the CAA requires the EPA to establish maximum achievable control technology (MACT) standards for each pollutant regulated under the rule. MACT is defined as the emission limitation achieved by the best performing 12% of sources in the source category. The EPA issued a proposed rule on March 16, 2011 that would establish national emissions standards for hazardous air pollutants (NESHAP) from coal- and oil-fired electric utility steam generating units. The rule, as currently proposed, may require all coal-fired power plants to install acid gas control technology, upgrade particulate control devices and/or install some other type of mercury control technology, such as sorbent injection. The EPA is receiving public comments on the proposed rule, and such public comments will be considered by the EPA prior to promulgating a final rule. Most of the United States coal-fired plants operated by the Company s subsidiaries have acid gas scrubbers or comparable control technologies, but as proposed there are other improvements to such control technologies that may be needed at some of our plants. Under the CAA, compliance is required within three years of the effective date of the rule; however, the compliance period for a unit, or group of units, may be extended by state permitting authorities (for one additional year) or through a determination by the President (for up to two additional years). At this time, the Company cannot predict the extent of the final regulations for hazardous air pollutants, but the cost of compliance with any such regulations could be material.

Other International Air Emissions Regulations and Legislation.

On January 18, 2011, the President of Chile approved a new air emissions regulation submitted to him by the national environmental regulatory agency (CONAMA). The new regulation establishes limits on emissions of NO_X, SO_2, metals and particulate matter for both existing and new thermal power plants, with more stringent limitations on new facilities. The regulation will become effective upon approval of the General Comptroller of Chile. The regulation will require AES Gener, our Chilean subsidiary, to install emissions reduction equipment at its existing thermal plants from late 2011 through 2015. The exact costs of compliance with such regulation have not yet been determined and the Company believes some of the compliance costs are contractually passed through to counterparties. However, the compliance costs could be material.

Cooling Water Intake Regulations.

As noted in our 2010 Form 10-K, the Company s U.S. facilities are subject to the U.S. Clean Water Act Section 316(b) rule issued by the EPA which seeks to protect fish and other aquatic organisms by requiring existing steam electric generating facilities to utilize the best technology available for cooling water intake structures. The EPA published a proposed rule establishing requirements under 316(b) regulations on April 20, 2011. The proposal, based on Section 316(b) of the U.S. Clean Water Act, establishes Best Technology Available (BTA) requirements regarding impingement standards with respect to aquatic organisms for all facilities that withdraw above 2 million gallons per day of water from certain water bodies and utilize at least 25% of the withdrawn water for cooling purposes. To meet these BTA requirements, as currently proposed, cooling water intake structures associated with once through cooling processes will need modifications of existing traveling screens that protect aquatic organisms and will need to add a fish return and handling system for each cooling system. Existing closed cycle cooling facilities may require upgrades to water intake structure systems. The proposal would also require comprehensive site-specific studies during the permitting process and may require closed-cycle cooling systems in order to meet BTA entrainment standards.

The EPA is accepting public comments on the proposed rule until July 2011, and until such regulations are final the EPA has instructed state regulatory agencies to use their best professional judgment in determining how to evaluate what constitutes best technology available for protecting fish and other aquatic organisms from cooling water intake structures. Certain states in which the Company operates power generation facilities, such as New York, have been delegated authority and are moving forward with best technology available determinations in the absence of any final rule from the EPA. On September 27, 2010, the California Office of Administrative Law approved a policy adopted by the California Water Resources Control Board with respect to power plant cooling water intake structures. This policy became effective on October 1, 2010, and establishes technology-based standards to implement Section 316(b) of the U.S. Clean Water Act. At this time, it is contemplated that the Company s Redondo Beach, Huntington Beach and Alamitos power plants in California will need to have in place best technology available by December 31, 2020, or repower the facilities. At present, the Company cannot predict the final requirements under Section 316(b) or whether compliance with the anticipated new 316(b) rule will have a material impact on our operations or results, but the Company expects that capital investments and/or modifications resulting from such requirements could be significant.

Waste Management.

In the course of operations, many of the Company s facilities generate coal combustion byproducts (CCB), including fly ash, requiring disposal or processing. On June 21, 2010 the EPA published in the Federal Register a proposed rule to regulate CCB under the Resource Conservation and Recovery Act (RCRA). The proposed rule provides two possible options for CCB regulation, and both options contemplate heightened structural integrity requirements for surface impoundments of CCB. The first option contemplates regulation of CCB as a hazardous waste subject to regulation under Subtitle C of the RCRA. Under this option, existing surface impoundments containing CCB would be required to be retrofitted with composite liners and these impoundments would likely be phased out over several years. State and/or federal permit programs would be developed for storage, transport and disposal of CCB. States could bring enforcement actions for non-compliance with permitting requirements, and the EPA would have oversight responsibilities as well as the authority to bring lawsuits for non-compliance. The second option contemplates regulation of CCB under Subtitle D of the RCRA. Under this option, the EPA would create national criteria applicable to CCB landfills and surface impoundments. Existing impoundments would also be required to be retrofitted with composite liners and would likely be phased out over several years. This option would not contain federal or state permitting requirements. The primary enforcement mechanism under regulation pursuant to Subtitle D would be private lawsuits.

The public comment period for this proposed regulation has expired, and EPA is required to consider the public comments prior to promulgating a final rule. Requirements under a final rule are expected to become effective by January 2012, with a compliance schedule of five years. While the exact impact and compliance cost associated with future regulations of CCB cannot be established until such regulations are finalized, there can be no assurance that the Company s businesses, financial condition or results of operations would not be materially and adversely affected by such regulations.

Recent Events

Subsequent to March 31, 2011, the Company continued to repurchase stock under the stock repurchase program announced on July 7, 2010. The Company has repurchased 2,774,700 shares at a cost of $36 million subsequent to March 31, 2011, bringing the cumulative total through May 6, 2011 to 16,100,536 shares at a total cost of $198 million (average price of $12.29 per share including commissions). As of May 6, 2011, $302 million of the $500 million authorized remained available under the stock repurchase program. For additional information, see Note 11 *Equity*.

On April 20, 2011, the Company announced the execution of a definitive agreement (the Merger Agreement) with DPL Inc.(DPL), the parent company of Dayton Power & Light Company, a utility company based in Ohio. Under the terms of the agreement, AES has agreed to acquire DPL for an enterprise value of $4.7 billion, consisting of cash proceeds of $3.5 billion and the assumption of net debt of approximately $1.2 billion. Through its operating subsidiaries DP&L and DPL Energy Resources, DPL serves over 500,000 customers in West Central Ohio. Additionally, DPL operates over 3,800 MW of power generation facilities and provides competitive retail energy services to industrial and commercial customers. Upon closing of the transaction, DPL will become a wholly-owned subsidiary of AES.

Simultaneously with the execution of the Merger Agreement, the Company entered into commitment letters (the Commitment Letters) with Bank of America, N.A. and Merrill Lynch, Pierce, Fenner & Smith Incorporated (together, the Bridge Providers). The Commitment Letters provide that, subject to certain customary terms and conditions, the Bridge Providers will provide senior unsecured bridge loans in an aggregate principal amount of $3.3 billion (the Bridge Facilities) to backstop a portion of the Company s payment obligations upon consummation of the merger. The Company will pay certain customary fees and expenses in connection therewith. To the extent funded, the agreement governing the Bridge Facilities will subject the Company to customary terms and covenants and will be subject to customary events of default. Permanent financing is expected to include a combination of non-recourse debt, the issuance of corporate debt at AES and cash on hand.

The Merger Agreement contains certain termination rights and conditions precedent. The Merger Agreement contains certain termination rights for DPL and AES and further provides that, if DPL terminates the Merger Agreement prior to DPL shareholder approval in order to pursue a superior offer, DPL is required to pay AES a termination fee of $106 million (or $53 million if DPL terminates the Merger Agreement within 45 days after its execution, in order to pursue a superior offer with a party that presents its offer within 30 days of the execution of the Merger Agreement). The consummation of the transaction is subject to approval of DPL shareholders, the Public Utilities Commission of Ohio, FERC, and antitrust review under the Hart-Scott-Rodino Act. Approvals are expected to be completed within six to nine months, although there can be no assurance that such approvals will be obtained. The transaction is also subject to certain other closing conditions. After the announcement of the transaction, certain lawsuits were filed seeking to enjoin the merger and/or seek unspecified monetary damages, some of which name AES as a defendant. The Company does not believe the suits will be successful; however, there can be no assurances regarding the outcome of the litigation.

Consolidated Results of Operations

	Three Months Ended March 31,			
	2011	2010	$ change	% change
	(in millions, except per share amounts)			
Revenue:				
Latin America Generation	$ 1,131	$ 983	$ 148	15%
Latin America Utilities	1,904	1,765	139	8%
North America Generation	372	391	(19)	-5%
North America Utilities	289	288	1	-%
Europe Generation	400	322	78	24%
Asia Generation	115	176	(61)	-35%
Corporate and Other(1)	305	250	55	22%
Eliminations(2)	(252)	(255)	3	-1%
Total Revenue	$ 4,264	$ 3,920	$ 344	9%
Gross Margin:				
Latin America Generation	$ 415	$ 344	$ 71	21%
Latin America Utilities	260	238	22	9%
North America Generation	94	102	(8)	-8%
North America Utilities	50	76	(26)	-34%
Europe Generation	81	102	(21)	-21%
Asia Generation	44	65	(21)	-32%
Corporate and Other(3)	60	24	36	150%
Eliminations(4)	12	10	2	20%
General and administrative expenses	(95)	(80)	(15)	19%
Interest expense	(351)	(381)	30	-8%
Interest income	95	108	(13)	-12%
Other expense	(17)	(12)	(5)	42%
Other income	16	9	7	78%
Gain on sale of investments	6	-	6	100%
Foreign currency transaction gains (losses) on net monetary position	33	(51)	84	165%
Income tax expense	(218)	(186)	(32)	17%
Net equity in earnings of affiliates	10	13	(3)	-23%
Income from continuing operations	495	381	114	30%
Income from operations of discontinued businesses	(12)	34	(46)	-135%
Loss from disposal of discontinued businesses	-	(13)	13	-%
Net income	483	402	81	20%
Noncontrolling interests:				
Income from continuing operations attributable to noncontrolling interests	(259)	(211)	(48)	23%
Income from discontinued operations attributable to noncontrolling interests	-	(4)	4	-%
Net income attributable to The AES Corporation	$ 224	$ 187	$ 37	20%
Per Share Data:				
Basic income per share from continuing operations	$ 0.30	$ 0.24	$ 0.06	25%
Diluted income per share from continuing operations	$ 0.30	$ 0.24	$ 0.06	25%

(1) Corporate and Other includes revenue from our generation and utilities businesses in Africa, utilities businesses in Europe, Wind Generation and other renewables initiatives.

(2) Represents inter-segment eliminations of revenue primarily related to transfers of electricity from Tietê (generation) to Eletropaulo (utility).

(3) Corporate and Other gross margin includes gross margin from our generation and utilities businesses in Africa, utilities businesses in Europe, Wind Generation and other renewables initiatives.

(4) Represents inter-segment eliminations of gross margin related to corporate charges for self insurance premiums.

Segment Analysis

Latin America

The following table summarizes revenue and gross margin for our Generation segment in Latin America for the periods indicated:

	For the Three Months Ended March 31, 2011	2010	% Change
	($ s in millions)		
Latin America Generation			
Revenue	$ 1,131	$ 983	15%
Gross Margin	$ 415	$ 344	21%

Excluding the favorable impact of foreign currency translation of $16 million, primarily in Brazil, generation revenue for the three months ended March 31, 2011 increased $132 million, or 13%, compared to the three months ended March 31, 2010 primarily due to:

- higher contract and spot prices of $82 million at Gener in Chile as a result of low water inflows in the interconnected central system;
- higher volume of $49 million in Panama and Colombia due to higher water inflows in the system;
- higher volume and energy prices of $52 million at our coal generation businesses in Argentina as a result of lower hydro generation;
- higher volume of $30 million at Gener driven by higher demand in the interconnected central system compared to the prior year as a result of the 2010 Chilean earthquake;
- higher contract prices of $14 million at Tiete in Brazil due to CPI indexation in the second half of 2010; and
- higher contract prices from PPAs indexed to coal of $8 million, higher ancillary services and third party gas sales of $7 million in the Dominican Republic.

These increases were partially offset by:

- lower spot prices of $54 million in Colombia and Panama due to higher water inflows in the system;
- lower volume sold at Tiete of $38 million due to lower requirements as per PPA settlement calculations; and
- a $16 million decrease driven by higher outages in Panama and Argentina.

Excluding the favorable impact of foreign currency translation of $14 million, primarily in Brazil, generation gross margin for the three months ended March 31, 2011 increased $57 million, or 17%, compared to the three months ended March 31, 2010 primarily due to:

- higher volume of $63 million in Panama and Colombia as a result of higher water inflows in the system;

higher volume of $49 million at Gener as a result of higher demand in the interconnected central system;

- higher spot and contract prices, partially offset by higher fuel costs, of $46 million at Gener;
- higher contract prices of $13 million at Tiete due to CPI indexation in the second half of 2010; and
- higher volume of $12 million at our coal generation businesses in Argentina, as a result of lower hydro generation.

These increases were partially offset by:

- lower volume of $40 million at Tiete due to lower requirements as per PPA settlement calculations;
- lower spot prices of $35 million in Colombia and Panama due to higher water inflows in the system;
- a decrease of $27 million as a result of higher outages primarily in Panama and Argentina; and
- higher fixed costs of $29 million across the region, as a result of higher repairs and maintenance costs and an increase in non-income tax rate (equity tax) in Colombia.

For the three months ended March 31, 2011, revenue increased 15%, while gross margin increased 21%. The difference in the increase in revenue compared to the increase in gross margin was primarily due to the favorable impact on gross margin of lower diesel consumption at Gener, lower spot purchases in Panama and lower spot prices in Colombia.

The following table summarizes revenue and gross margin for our Utilities segment in Latin America for the periods indicated:

	For the Three Months Ended March 31,		
	2011	**2010**	**% Change**
		($ s in millions)	
Latin America Utilities			
Revenue	$ 1,904	$ 1,765	8%
Gross Margin	$ 260	$ 238	9%

Excluding the favorable impact of foreign currency translation of $128 million, primarily in Brazil, utilities revenue for the three months ended March 31, 2011 increased $11 million, or 1%, compared to the three months ended March 31, 2010 primarily due to:

- higher volume of $87 million attributable to increased market demand across the region.

This increase was partially offset by:

- lower tariffs of $70 million, primarily related to the unfavorable impact on rates in Brazil of adjustments to regulatory liabilities, and lower energy prices across our Latin America utility businesses associated with energy purchases and transmission costs passed through to customers of $48 million.

Excluding the favorable impact of foreign currency translation of $19 million, primarily in Brazil, utilities gross margin for the three months ended March 31, 2011 increased $3 million, or 1%, compared to the three months ended March 31, 2010 primarily due to:

- higher volume of $63 million attributable to the increased market demand, across the region.

This increase was partially offset by:

lower tariffs of $23 million primarily related to the unfavorable impact on rates in Brazil of adjustments to regulatory liabilities;

higher fixed costs of $18 million in Brazil, primarily due to higher employee costs, provision for value added tax (VAT) on commercial losses, regulatory penalties, maintenance costs and consulting expenses, partially offset by lower labor contingencies; and

higher depreciation of $15 million at our businesses in Brazil, mainly due to the change in useful lives and salvage values of property, plant and equipment, as a result of new regulatory information received.

North America

The following table summarizes revenue and gross margin for our Generation segment in North America for the periods indicated:

	For the Three Months Ended March 31, 2011	2010	% Change
	($ s in millions)		
North America Generation			
Revenue	$ 372	$ 391	-5%
Gross Margin	$ 94	$ 102	-8%

Excluding the favorable impact of foreign currency translation of $5 million, generation revenue for the three months ended March 31, 2011 decreased $24 million, or 6%, compared to the three months ended March 31, 2010 primarily due to:

a decrease of $18 million at Thames in Connecticut due to the plant shutdown in January 2011 and its deconsolidation as of February 2011 as a result of loss of control to the Court when it filed for bankruptcy protection;

lower rates and volume of $11 million at Merida in Mexico; and

a decrease in volume of $8 million at Deepwater in Texas due to the layup of the plant caused by high fuel costs and diminishing power prices.

These decreases were partially offset by:

an increase of $8 million at TEG/TEP in Mexico primarily due to the pass-through of backup power for scheduled outages in 2011; and

higher rates of $4 million in Puerto Rico.

Generation gross margin for the three months ended March 31, 2011 decreased $8 million, or 8%, compared to the three months ended March 31, 2010 primarily due to:

a decrease of $9 million at TEG/TEP primarily due to a combination of forced and scheduled outages;

higher capacity penalties and fixed costs of $4 million in Puerto Rico;

a net decrease of $3 million at Deepwater due to the layup of the plant caused by high fuel costs and diminishing power prices, partially offset by lower fuel purchases; and higher fuel consumption and prices of $3 million in Hawaii.

These decreases were partially offset by:

an increase of $5 million and $4 million at TEG/TEP and Hawaii, respectively, due to a favorable impact of mark-to-market derivatives.

The following table summarizes revenue and gross margin for our Utilities segment in North America for the periods indicated:

	For the Three Months Ended March 31, 2011	2010	% Change
		($ s in millions)	
North America Utilities			
Revenue	$ 289	$ 288	0%
Gross Margin	$ 50	$ 76	-34%

Utilities revenue for the three months ended March 31, 2011 increased $1 million compared to the three months ended March 31, 2010 primarily due to:

higher retail revenue of $11 million primarily due to higher fuel adjustment charges.

This increase was partially offset by:

lower wholesale revenue of $11 million primarily due to increased generating unit outages.

Utilities gross margin for the three months ended March 31, 2011 decreased $26 million, or 34%, compared to the three months ended March 31, 2010 primarily due to:

higher maintenance expense of $8 million primarily due to scheduled generating unit outages;

lower wholesale margin of $7 million due to decreased volume from generating unit outages; and

lower retail margin of $6 million primarily due to a non-recurring charge to retail revenue.

For the three months ended March 31, 2011, revenue remained flat while gross margin decreased 34%. The difference in the variance in revenue compared to the decrease in gross margin was primarily due to increased maintenance costs and a non-recurring charge to retail revenue.

Europe

The following table summarizes revenue and gross margin for the Generation segment in Europe for the periods indicated:

	For the Three Months Ended March 31, 2011	2010	% Change
		($ s in millions)	
Europe Generation			
Revenue	$ 400	$ 322	24%
Gross Margin	$ 81	$ 102	-21%

Excluding the favorable impact of foreign currency translation of $2 million, generation revenue for the three months ended March 31, 2011 increased $76 million, or 24%, compared to the three months ended March 31, 2010 primarily due to:

$108 million from the operations of Ballylumford in Northern Ireland, which was acquired in August 2010.

This increase was partially offset by:

lower revenue of $30 million at Kilroot in Northern Ireland primarily driven by the cancellation of the long-term PPA and related supplementary agreements in November 2010; and

a net decrease of $7 million in Hungary due to lower contract sales partially offset by higher rates on ancillary services.

Excluding the favorable impact of foreign currency translation of $1 million, generation gross margin for the three months ended March 31, 2011 decreased $22 million, or 22%, compared to the three months ended March 31, 2010 primarily due to:

lower gross margin of $39 million at Kilroot primarily driven by the cancellation of the long-term PPA and related supplementary agreements in November 2010;

increased costs of $14 million at Maritza primarily due to delays in the commencement of commercial operations; and

lower gross margin of $10 million at Hungary primarily due to lower contract sales.

These decreases were partially offset by:

$34 million from the operations of Ballylumford acquired in August 2010.

For the three months ended March 31, 2011, revenue increased 24%, while gross margin decreased 21%. The difference between the increase in revenue compared to the decrease in gross margin was primarily due to the acquisition of Ballylumford that had a larger positive impact on revenue than gross margin and increased fixed costs at Maritza due to delays in the commencement of commercial operations.

Asia

The following table summarizes revenue and gross margin for the Generation segment in Asia for the periods indicated:

	For the Three Months Ended March 31, 2011	2010	% Change
	($ s in millions)		
Asia Generation			
Revenue	$ 115	$ 176	-35%
Gross Margin	$ 44	$ 65	-32%

Excluding the favorable impact of foreign currency translation of $5 million in the Philippines, generation revenue for the three months ended March 31, 2011 decreased $66 million, or 38%, compared to the three months ended March 31, 2010 primarily due to:

lower generation volume of $40 million at Kelanitissa in Sri Lanka attributable to the plant being on reserve shutdown during the majority of the three months ended March 31, 2011. There was lower off-taker demand as a result of better hydrology and the addition of a new coal plant to the grid, thus increasing capacity in the market; and lower generation volume and rates of $19 million at Masinloc in the Philippines. Spot market demand and prices were lower during the three months ended March 31, 2011 due to lower electricity demand as a result of cooler weather, and higher available capacity in the grid.

Excluding the favorable impact of foreign currency translation of $2 million in the Philippines, generation gross margin for the three months ended March 31, 2011 decreased $23 million, or 35%, compared to the three months ended March 31, 2010 primarily due to lower volume of $25 million at Masinloc attributable to lower market demand, as explained above.

Corporate and Other

Corporate and Other includes the net operating results from our generation and utilities businesses in Africa, utilities businesses in Europe, Wind Generation and other climate solutions and renewables projects which are immaterial for the purposes of separate segment disclosure. The following table excludes inter-segment activity and summarizes revenue and gross margin for Corporate and Other entities for the periods indicated:

	For the Three Months Ended March 31,		
	2011	2010	% Change
	($ s in millions)		
Revenue			
Europe Utilities	$ 110	$ 93	18%
Africa Utilities	110	95	16%
Africa Generation	21	21	0%
Wind Generation	64	42	52%
Corp/Other	7	6	17%
Eliminations[1]	(7)	(7)	0%
Total Corporate and Other	$ 305	$ 250	22%
Gross Margin			
Europe Utilities	$ 10	$ 7	43%
Africa Utilities	18	(1)	1900%
Africa Generation	13	12	8%
Wind Generation	24	7	243%
Corp/Other	(6)	(3)	100%
Eliminations[2]	1	2	-50%
Total Corporate and Other	$ 60	$ 24	150%

(1) Represents eliminations of revenue primarily related to transfers of electricity in Africa from Dibamba (generation) to Sonel (utility).

(2) Represents eliminations of gross margin related to corporate charges for self insurance premiums.

Corporate and Other revenue for the three months ended March 31, 2011 increased $55 million, or 22%, compared to the three months ended March 31, 2010 primarily due to:

higher tariff and volume of $29 million at Sonel in Cameroon and our utility businesses in Ukraine;

incremental revenue of $15 million from a new wind generation project in Bulgaria that commenced operations in March 2010; and

higher volume of $7 million across our wind generation businesses.

Corporate and Other gross margin for the three months ended March 31, 2011 increased $36 million, or 150%, compared to the three months ended March 31, 2010 primarily due to:

- higher tariff and volume of $22 million at Sonel and our utility businesses in Ukraine;
- $11 million from the new wind generation project as discussed above; and
- higher volume of $7 million across our wind generation businesses.

These increases were partially offset by:

- an overall increase of $7 million in fixed costs across the businesses.

For the three months ended March 31, 2011, revenue increased 22%, while gross margin increased 150%. The difference in the increase in revenue and the increase in gross margin was primarily due to lower fuel consumption at Sonel as a result of higher generation at hydro plants.

General and administrative expense

General and administrative expense increased $15 million, or 19%, to $95 million for the three months ended March 31, 2011 from $80 million for the three months ended March 31, 2010. The increase was primarily due to a credit related to employee benefits recognized in 2010 as well as 2011 professional fees associated with cost savings initiatives.

Interest expense

Interest expense decreased $30 million, or 8%, to $351 million for the three months ended March 31, 2011 from $381 million for the three months ended March 31, 2010. The decrease was primarily due to the retirement of debt at the Parent Company.

Interest income

Interest income decreased $13 million, or 12%, to $95 million for the three months ended March 31, 2011 from $108 million for the three months ended March 31, 2010. The decrease was primarily due to the settlement of a dispute related to inflation adjustments for energy sales at Tiete in 2010, partially offset by a higher average balance in short term investments at Eletropaulo in 2011.

Other expense

Other expense for the three months ended March 31, 2011 and 2010 of $17 million and $12 million, respectively, was primarily comprised of losses on disposal of assets at Eletropaulo.

Other income

Other income was $16 million and $9 million for the three months ended March 31, 2011 and 2010, respectively.

Gain on sale of investments

Gain on sale of investments for the three months ended March 31, 2011 was $6 million, related to our sale of Wuhu, an equity investment in China that was accounted for under the equity method of accounting. There was no gain on sale of investments for the three months ended March 31, 2010.

Foreign currency transaction gains (losses) on net monetary position

Foreign currency transaction gains (losses) were as follows:

	Three Months Ended March 31,			
	2011		2010	
	(in millions)			
AES Corporation	$	33	$	(32)
Chile		(5)		(9)
Philippines		6		9
Brazil		-		(7)
Other		(1)		(12)
Total[(1)]	$	33	$	(51)

(1) Includes $2 million and $(6) million gains (losses) on foreign currency derivative contracts for the three months ended March 31, 2011 and 2010, respectively.

The Company recognized foreign currency transaction gains of $33 million for the three months ended March 31, 2011. These were primarily due to increases in the valuation of foreign currency denominated notes receivable and cash balances, resulting from the strengthening of the Euro and British Pound.

The Company recognized foreign currency transaction losses of $51 million for the three months ended March 31, 2010. These consisted primarily of losses at The AES Corporation and in Chile and Brazil, partially offset by gains in the Philippines.

Losses of $32 million at The AES Corporation were primarily due to remeasurement of notes receivable denominated in Euro, partially offset by gains on British Pound denominated debt.

Losses of $9 million in Chile were primarily due to a 3% devaluation of the Chilean Peso in the first quarter of 2010, resulting in losses at Gener (a U.S. Dollar functional currency subsidiary) from working capital denominated in Chilean Pesos, primarily cash, accounts receivable and VAT receivables. These losses were partially offset by gains of $3 million on foreign currency derivatives.

Losses of $7 million in Brazil were primarily due to the realization of deferred exchange variances on past energy purchases made by Eletropaulo denominated in U.S. Dollar and the devaluation of the Brazilian Real by 2%, resulting in losses at Uruguaiana associated with its U.S. Dollar denominated liabilities.

Gains of $9 million in the Philippines were primarily due to remeasurement gains at Masinloc (a Philippine Peso functional currency subsidiary) on U.S. Dollar denominated debt resulting from appreciation of the Philippine Peso.

Income tax expense

Income tax expense on continuing operations increased $32 million, or 17%, to $218 million for the three months ended March 31, 2011 compared to $186 million for the three months ended March 31, 2010. The Company s effective tax rates were 31% and 34% for the three months ended March 31, 2011 and 2010, respectively.

The net decrease in the effective tax rate for the three months ended March 31, 2011 compared to the same period in 2010 was primarily due to the extension of a favorable U.S. tax law impacting distributions from certain non-U.S. subsidiaries.

Net equity in earnings of affiliates

Net equity in earnings of affiliates decreased $3 million, or 23%, to $10 million for the three months ended March 31, 2011 from $13 million for the three months ended March 31, 2010. The decrease was primarily due to lower generation, higher coal prices and no tariff adjustment at Yangcheng in China, as well as our share of an impairment at AES Solar resulting from legislation on the restrictions in size of certain future solar projects in Italy. These decreases were partially offset by increased earnings at Guacolda in Chile and OPGC in India.

Income from continuing operations attributable to noncontrolling interests

Income from continuing operations attributable to noncontrolling interests increased $48 million, or 23%, to $259 million for the three months ended March 31, 2011 from $211 million for the three months ended March 31, 2010. The increase was primarily due to an increase in spot electricity sales at Gener as well as an increase at Armenia Mountain as a result of the effect of the proceeds from a cash grant on the allocation of income to the noncontrolling interest in the first quarter of 2010. The noncontrolling interest for Armenia Mountain is accounted for under the hypothetical liquidation at book value method, which uses a balance sheet approach.

Discontinued operations

As further discussed in Note 14 *Discontinued Operations and Held for Sale Businesses*, discontinued operations includes the results of the following generation businesses: Eastern Energy including Cayuga, Greenidge, Somerset and Westover (held for sale in March 2011); Borsod and Tiszapalkonya (held for sale in March 2011); Ras Laffan (sold in October 2010); Barka (sold in August 2010) and Lal Pir and Pak Gen (sold in June 2010). Prior periods have been restated to reflect these businesses within Discontinued Operations for all periods presented.

For the three months ended March 31, 2011 and 2010, operations of discontinued businesses, net of tax and income attributable to noncontrolling interests, was a net loss of $12 million and net income of $24 million, respectively, and reflected the operations of our 100% stake in Eastern Energy, four coal-fired power plants in New York, our 100% stake in Borsod, a biomass and coal fired-facility in Hungary, our 100% stake in Tiszapalkonya, a multi-fuel facility in Hungary, our 55% stake in Ras Laffan, a combined cycle gas facility and water desalination plant in Qatar, our 35% stake in Barka, a combined cycle gas facility and water desalination plant in Oman, and our 55% stake in Pak Gen and Lal Pir, two oil-fired facilities in Pakistan. As of March 31, 2010, the Company compared the carrying value of the held for sale assets and liabilities to the agreed upon sales proceeds of Lal Pir and Pak Gen and recognized an impairment of $13 million ($7 million, net of tax and noncontrolling interests).

Capital Resources and Liquidity

Overview

As of March 31, 2011, the Company had unrestricted cash and cash equivalents of $2.0 billion, of which approximately $546 million was held at the Parent Company and qualified holding companies, and short term investments of $1.7 billion. In addition, we had restricted cash and debt service reserves of $1.2 billion. The Company also had non-recourse and recourse aggregate principal amounts of debt outstanding of $15.1 billion and $4.4 billion, respectively. Of the approximately $2.6 billion of our short-term non-recourse debt, $1.2 billion was presented as current because it is due in the next twelve months and $1.4 billion relates to defaulted debt. We expect such current maturities will be repaid from net cash provided by operating activities of the subsidiary to which the debt relates or through opportunistic refinancing activity or some combination thereof. Approximately $200 million of our recourse debt matures within the next twelve months, which we expect to repay using cash on hand at the Parent Company or through net cash provided by operating activities. See further discussion of Parent Company Liquidity below.

The Company has two types of debt reported on its consolidated balance sheet: non-recourse and recourse debt. Non-recourse debt is used to fund investments and capital expenditures for construction and acquisition of our electric power plants, wind projects and distribution facilities at our subsidiaries. Non-recourse debt is generally secured by the capital stock, physical assets, contracts and cash flows of the related subsidiary. The default risk is limited to the respective business and is without recourse to the Parent Company and other subsidiaries. Recourse debt is direct borrowings by the Parent Company and is used to fund development, construction or acquisitions, including funding for equity investments or to provide loans to the Parent Company s subsidiaries or affiliates. This Parent Company debt is with recourse to the Parent Company and is structurally subordinated to the debt of the Parent Company s subsidiaries or affiliates, except to the extent such subsidiaries or affiliates guarantee the Parent Company s debt.

We rely mainly on long-term debt obligations to fund our construction activities. We have, to the extent available at acceptable terms, utilized non-recourse debt to fund a significant portion of the capital expenditures and investments required to construct and acquire our electric power plants, distribution companies and related assets. Our non-recourse financing is designed to limit cross default risk to the Parent Company or other subsidiaries and affiliates. Our non-recourse long-term debt is a combination of fixed and variable interest rate instruments. Generally, a portion or all of the variable rate debt is fixed through the use of interest rate swaps. In addition, the debt is typically denominated in the currency that matches the currency of the revenue expected to be generated from the benefiting project, thereby reducing currency risk. In certain cases, the currency is matched through the use of derivative instruments. The majority of our non-recourse debt is funded by international commercial banks, with debt capacity supplemented by multilaterals and local regional banks.

Given our long-term debt obligations, the Company is subject to interest rate risk on debt balances that accrue interest at variable rates. When possible, the Company will borrow funds at fixed interest rates or hedge its variable rate debt to fix its interest costs on such obligations. In addition, the Company has historically tried to maintain at least 70% of its consolidated long-term obligations at fixed interest rates, including fixing the interest rate through the use of interest rate swaps. These efforts apply to the notional amount of the swaps compared to the amount of related underlying debt. Presently, the Parent Company s only direct exposure to variable interest rate debt relates to indebtedness under its senior secured credit facility. On a consolidated basis, of the Company s $19.5 billion of total debt outstanding as of March 31, 2011, approximately $5.2 billion bore interest at variable rates that were not subject to a derivative instrument which fixed the interest rate.

In addition to utilizing non-recourse debt at a subsidiary level when available, the Parent Company provides a portion, or in certain instances all, of the remaining long-term financing or credit required to fund development, construction or acquisition of a particular project. These investments have generally taken the form of equity investments or intercompany loans, which are subordinated to the project s non-recourse loans. We generally obtain the funds for these investments from our cash flows from operations, proceeds from the sales of assets and/or the proceeds from our issuances of debt, common stock and other securities. Similarly, in certain of our businesses, the Parent Company may provide financial guarantees or other credit support for the benefit of counterparties who have entered into contracts for the purchase or sale of electricity, equipment or other services with our subsidiaries or lenders. In such circumstances, if a business defaults on its payment or supply obligation, the Parent Company will be responsible for the business obligations up to the amount provided for in the relevant guarantee or other credit support. At March 31, 2011, the Parent Company had provided outstanding financial and performance-related guarantees or other credit support commitments to or for the benefit of our businesses, which were limited by the terms of the agreements, of approximately $344 million in aggregate (excluding investment commitments and those collateralized by letters of credit and other obligations discussed below).

As a result of the Parent Company s below investment grade rating, counterparties may be unwilling to accept our general unsecured commitments to provide credit support. Accordingly, with respect to both new and existing commitments, the Parent Company may be required to provide some other form of assurance, such as a letter of credit, to backstop or replace our credit support. The Parent Company may not be able to provide adequate assurances to such counterparties. To the extent we are required and able to provide letters of credit or other collateral to such counterparties, this will reduce the amount of credit available to us to meet our other liquidity needs. At March 31, 2011, we had $28 million in letters of credit outstanding, provided under the senior secured credit facility, and $27 million in cash collateralized letters of credit outstanding outside of the senior secured credit facility. These letters of credit operate to guarantee performance relating to certain project development activities and business operations. During the quarter ended March 31, 2011, the Company paid letter of credit fees ranging from 0.25% to 3.25% per annum on the outstanding amounts.

We expect to continue to seek, where possible, non-recourse debt financing in connection with the assets or businesses that we or our affiliates may develop, construct or acquire. However, depending on local and global market conditions and the unique characteristics of individual businesses, non-recourse debt may not be available on economically attractive terms or at all. See *Global Economic Conditions* discussion above. If we decide not to provide any additional funding or credit support to a subsidiary project that is under construction or has near-term debt payment obligations and that subsidiary is unable to obtain additional non-recourse debt, such subsidiary may become insolvent, and we may lose our investment in that subsidiary. Additionally, if any of our subsidiaries lose a significant customer, the subsidiary may need to withdraw from a project or restructure the non-recourse debt financing. If we or the subsidiary choose not to proceed with a project or are unable to successfully complete a restructuring of the non-recourse debt, we may lose our investment in that subsidiary.

Many of our subsidiaries depend on timely and continued access to capital markets to manage their liquidity needs. The inability to raise capital on favorable terms, to refinance existing indebtedness or to fund operations and other commitments during times of political or economic uncertainty may have material adverse effects on the financial condition and results of operations of those subsidiaries. In addition, changes in the timing of tariff increases or delays in the regulatory determinations under the relevant concessions could affect the cash flows and results of operations of our businesses.

As of March 31, 2011, the Company had approximately $351 million of trade accounts receivable related to certain of its generation and utility businesses in Latin America classified as other long-term assets. These consist primarily of trade accounts receivable that, pursuant to amended agreements or government resolutions, have collection periods that extend beyond March 31, 2012, or one year past the balance sheet date. The Company is actively collecting these receivables and believes such amounts are collectible based on collection history and performance under agreements. Additionally, the current portion of these trade accounts receivable was $83 million at March 31, 2011.

Consolidated Cash Flows. During the three months ended March 31, 2011, cash and cash equivalents decreased $544 million from March 31, 2010 to $2.0 billion. The decrease in cash and cash equivalents was due to $505 million of cash provided by operating activities, $601 million of cash used for investing activities, $463 million of cash used for financing activities and the favorable effect of foreign currency exchange rates on cash of $15 million.

Operating Activities

Net cash provided by operating activities decreased $163 million to $505 million during the three months ended March 31, 2011 compared to $668 million during the three months ended March 31, 2010. This net decrease was primarily due to the following:

- a decrease of $105 million at our Latin American Generation businesses primarily due to higher payments for income taxes, higher collections of past due government receivables in the Dominican Republic in 2010 as well as higher collections of outstanding VAT receivables in 2010 related to construction activity at Gener partially offset by higher gross margin; and

- a decrease of $44 million at our Asia Generation businesses primarily due to lower operating income and higher working capital requirements at Masinloc in the Philippines as well as the sale of Lal Pir and Pak Gen, Barka and Ras Laffan in 2010.

Investing Activities

Net cash used for investing activities increased $6 million to $601 million during the three months ended March 31, 2011 compared to $595 million during the three months ended March 31, 2010. This net increase was primarily due to the following:

- an increase of $104 million for acquisitions, net of cash acquired, for the three months ended March 31, 2011. The increase was primarily due to the acquisition of our equity investment in Entek in February 2011 for $136 million. The increase was partially offset by a decrease of $34 million related to the purchase of Your Energy Limited in March 2010;

- a decrease of $91 million in proceeds from the sale of businesses for the three months ended March 31, 2011. The decrease was primarily due to the final settlement proceeds of $99 million received in January 2010 from the termination of a management agreement with Kazakhmys PLC in Kazakhstan related to Ekibastuz and Maikuben which were sold in May 2008; and

- an increase of $79 million in other investing activities primarily due to grant proceeds of $69 million received at Armenia Mountain in 2010; partially offset by

- an increase of $156 million to $60 million from the sale of short-term investments, net of purchases, for the three months ended March 31, 2011 from $96 million from the purchase of short-term investments, net of sales for the three months ended March 31, 2010. The increase was primarily due to an increase in net sales of $162 million at our Brazilian subsidiaries, which were partially offset by an increase in net purchases of $14 million at Gener;

- a decrease of $57 million in funding requirements for restricted cash balances for the three months ended March 31, 2011 compared to the three months ended March 31, 2010. During the three months ended March 31, 2011, $11 million of funds were transferred out of restricted cash while during the three months ended March 31, 2010, $46 million was transferred to restricted cash primarily for redemptions at Kilroot in Northern Ireland; and

- a decrease of $54 million in debt service reserves and other assets during the three months ended March 31, 2011 compared to the three months ended March 31, 2010. During the three months ended March 31, 2011, $7 million of funds were transferred to debt service reserves and other assets while during the three months ended March 31, 2010, $61 million was transferred to debt service reserves and other assets primarily due to the refund of a VAT receivable at Gener.

Financing Activities

Net cash used for financing activities increased $2.0 billion to $463 million during the three months ended March 31, 2011 compared to net cash provided by financing activities of $1.5 billion during the three months ended March 31, 2010. This net increase was primarily due to the following:

- a $1.6 billion decrease in the issuance of common stock, net of transaction costs due to the CIC transaction in 2010;

- a $268 million increase in repayments of recourse debt due to scheduled maturities of debt at the Parent Company;

- a decrease of $101 million in proceeds from issuances of non-recourse debt primarily due to decreases of $73 million at Gener, $27 million at St. Nikola, $21 million at Kribi, $20 million at Maritza and $18 million at Eastern Energy. These decreases were partially offset by increases of $25 million at Puerto Rico, $19 million at Mountain View IV and $18 million at Sonel;

- a $63 million acquisition of treasury stock; partially offset by

- a $29 million decrease in distributions to noncontrolling interests primarily due to a decrease of $69 million at Armenia Mountain, partially offset by a $21 million increase at Gener.

Parent Company Liquidity

The following discussion of Parent Company Liquidity has been included because we believe it is a useful measure of the liquidity available to The AES Corporation, or the Parent Company, given the non-recourse nature of most of our indebtedness. Parent Company liquidity as outlined below is a non-GAAP measure and should not be construed as an alternative to cash and cash equivalents which are determined in accordance with GAAP, as a measure of liquidity. Cash and cash equivalents are disclosed in the condensed consolidated statements of cash flows. Parent Company liquidity may differ from similarly titled measures used by other companies. The principal sources of liquidity at the Parent Company level are:

- dividends and other distributions from our subsidiaries, including refinancing proceeds;

- proceeds from debt and equity financings at the Parent Company level, including availability under our credit facilities; and

- proceeds from asset sales.

Cash requirements at the Parent Company level are primarily to fund:

- interest;

- principal repayments of debt;

- acquisitions;

- construction commitments;

- other equity commitments;

- equity repurchases;

- taxes; and

- Parent Company overhead and development costs.

The Company defines Parent Company Liquidity as cash available to the Parent Company plus available borrowings under existing credit facilities. The cash held at qualified holding companies represents cash sent to subsidiaries of the Company domiciled outside of the U.S. Such subsidiaries have no contractual restrictions on their ability to send cash to the Parent Company. Parent Company Liquidity is reconciled to its most directly comparable U.S. GAAP financial measure, cash and cash equivalents at March 31, 2011 and December 31, 2010 as follows:

Parent Company Liquidity	March 31, 2011	December 31, 2010
	(in millions)	
Consolidated cash and cash equivalents	$ 2,008	$ 2,552
Less: Cash and cash equivalents at subsidiaries	(1,462)	(1,430)
Parent and qualified holding companies cash and cash equivalents	546	1,122
Commitments under Parent credit facilities	800	800
Less: Borrowings and letters of credit under the credit facilities	(28)	(85)
Borrowings available under Parent credit facilities	772	715
Total Parent Company Liquidity	$ 1,318	$ 1,837

The following table summarizes our Parent Company contingent contractual obligations as of March 31, 2011:

Contingent contractual obligations	Amount (in millions)	Number of Agreements	Maximum Exposure Range for Each Agreement (in millions)
Guarantees	$ 344	22	<$ 1 - $53
Letters of credit under the senior secured credit facility	28	14	<$ 1 - $16
Cash collateralized letters of credit	27	12	<$ 1 - $15
Total	$ 399	48	

As of March 31, 2011, the Company had $58 million of commitments to invest in subsidiaries under construction and to purchase related equipment that were not included in the letters of credit discussed above. The Company expects to fund these net investment commitments in 2011. The exact payment schedules will be dictated by the construction milestones. We expect to fund these commitments from a combination of current liquidity and internally generated Parent Company cash flow.

We have a diverse portfolio of performance related contingent contractual obligations. These obligations are designed to cover potential risks and only require payment if certain targets are not met or certain contingencies occur. The risks associated with these obligations include change of control, construction cost overruns, subsidiary default, political risk, tax indemnities, spot market power prices, sponsor support and liquidated damages under power sales agreements for projects in development, in operation and under construction. While we do not expect that we will be required to fund any material amounts under these contingent contractual obligations during 2012 or beyond, many of the events which would give rise to such obligations are beyond our control. We can provide no assurance that we will be able to fund our obligations under these contingent contractual obligations if we are required to make substantial payments thereunder.

While we believe that our sources of liquidity will be adequate to meet our needs for the foreseeable future, this belief is based on a number of material assumptions, including, without limitation, assumptions about our ability to access the capital markets (see *Key Trends and Uncertainties* and *Global Economic Conditions*), the operating and financial performance of our subsidiaries, currency exchange rates, power market pool prices, and the ability of our subsidiaries to pay dividends. In addition, our subsidiaries ability to declare and pay cash dividends to us (at the Parent Company level) is subject to certain limitations contained in loans, governmental provisions and other agreements. We can provide no assurance that these sources will be available when needed or that the actual cash requirements will not be greater than anticipated. We have met our interim needs for shorter-term and working capital financing at the Parent Company level with our senior secured credit facility. See Item 1A. Risk Factors, *The AES Corporation is a holding company and its ability to make payments on its outstanding indebtedness, including its public debt securities, is dependent upon the receipt of funds from its subsidiaries by way of dividends, fees, interest, loans or otherwise*. of the Company s 2010 Form 10-K.

Various debt instruments at the Parent Company level, including our senior secured credit facility, contain certain restrictive covenants. The covenants provide for, among other items:

- limitations on other indebtedness, liens, investments and guarantees;
- limitations on dividends, stock repurchases and other equity transactions;
- restrictions and limitations on mergers and acquisitions, sales of assets, leases, transactions with affiliates and off-balance sheet and derivative arrangements;
- maintenance of certain financial ratios; and
- financial and other reporting requirements.

As of March 31, 2011, we were in compliance with these covenants at the Parent Company level.

Non-Recourse Debt:

While the lenders under our non-recourse debt financings generally do not have direct recourse to the Parent Company, defaults thereunder can still have important consequences for our results of operations and liquidity, including, without limitation:

- reducing our cash flows as the subsidiary will typically be prohibited from distributing cash to the Parent Company during the time period of any default;
- triggering our obligation to make payments under any financial guarantee, letter of credit or other credit support we have provided to or on behalf of such subsidiary;
- causing us to record a loss in the event the lender forecloses on the assets; and
- triggering defaults in our outstanding debt at the Parent Company.

For example, our senior secured credit facilities and outstanding debt securities at the Parent Company include events of default for certain bankruptcy related events involving material subsidiaries. In addition, our revolving credit agreement at the Parent Company includes events of default related to payment defaults and accelerations of outstanding debt of material subsidiaries.

Some of our subsidiaries are currently in default with respect to all or a portion of their outstanding indebtedness. The total non-recourse debt classified as current in the accompanying condensed consolidated balance sheet amounts to $2.6 billion. The portion of current debt related to such defaults was $1.4 billion at March 31, 2011, all of which was non-recourse debt related to four subsidiaries Maritza, Sonel, Kelanitissa and Aixi.

None of the subsidiaries that are currently in default are subsidiaries that met the applicable definition of materiality under AES corporate debt agreements as of March 31, 2011 in order for such defaults to trigger an event of default or permit acceleration under such indebtedness. However, as a result of additional dispositions of assets, other significant reductions in asset carrying values or other matters in the future that may impact our financial position and results of operations or the financial position of the individual subsidiary, it is possible that one or more of these subsidiaries could fall within the definition of a material subsidiary and thereby upon an acceleration trigger an event of default and possible acceleration of the indebtedness under the AES Parent Company s outstanding debt securities.

Critical Accounting Policies and Estimates

The condensed consolidated financial statements of AES are prepared in conformity with generally accepted accounting principles in the United States of America, which requires the use of estimates, judgments and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the periods presented. The Company s significant accounting policies are described in Note 1 *General and Summary of Significant Accounting Policies* to the consolidated financial statements included in the Company s 2010 Form 10-K. The Company s critical accounting estimates are described in Management s Discussion and Analysis of Financial Condition and Results of Operations included in the Company s 2010 Form 10-K. An accounting estimate is considered critical if the estimate requires management to make an assumption about matters that were highly uncertain at the time the estimate was made, different estimates reasonably could have been used, or if changes in the estimate that would have a material impact on the Company s financial condition or results of operations are reasonably likely to occur from period to period. Management believes that the accounting estimates employed are appropriate and resulting balances are reasonable; however, actual results could differ from the original estimates, requiring adjustments to these balances in future periods.

The Company has reviewed and determined that those policies remain the Company s critical accounting policies as of and for the three months ended March 31, 2011.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Overview Regarding Market Risks

We are a global company in the power generation and distribution businesses. We own and/or operate power plants to generate and sell power to wholesale customers. We also own and/or operate utilities to distribute, transmit and sell electricity to end-user customers. Our primary market risk exposure is to the price of commodities particularly electricity, oil, natural gas, coal and environmental credits. We operate in multiple countries and as such are subject to volatility in exchange rates at the subsidiary level and between our functional currency, the U.S. Dollar, and currencies of the countries in which we operate. We are also exposed to interest rate fluctuations due to our issuance of debt and related financial instruments.

These disclosures set forth in this Item 3 are based upon a number of assumptions, and actual impacts to the Company may not follow the assumptions made by the Company. The safe harbor provided in Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 shall apply to the disclosures contained in this Item 3. For further information regarding market risk, see Item 1A. Risk Factors, *Our financial position and results of operations may fluctuate significantly due to fluctuations in currency exchange rates experienced at our foreign operations* , *Our businesses may incur substantial costs and liabilities and be exposed to price volatility as a result of risks associated with the wholesale electricity markets, which could have a material adverse effect on our financial performance* and *We may not be adequately hedged against our exposure to changes in commodity prices or interest rates* in the Company s 2010 Form 10-K.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the price of electricity, fuels and environmental credits. Although we primarily consist of businesses with long-term contracts or retail sales concessions, a portion of our current and expected future revenues are derived from businesses without significant long-term revenue or supply contracts. These businesses subject our operational results to the volatility of prices for electricity, fuels and environmental credits in competitive markets. We employ risk management strategies to hedge our financial performance against the effects of fluctuations in energy commodity prices. The implementation of these strategies can involve the use of physical and financial commodity contracts, futures, swaps and options.

When hedging the output of our generation assets, we have PPAs or other hedging instruments that lock in the spread per MWh between variable costs, such as fuel, to generate a unit of electricity and the price at which the electricity can be sold. The portion of our sales and purchases that are not subject to such agreements will be exposed to commodity price risk.

AES businesses will see variance in variable margin performance as global commodity prices shift. For the balance of 2011, excluding operations from the Company s merchant generation assets in New York we project pre-tax earnings exposure would be approximately $15 million for a $10/barrel move in oil, $25 million for a $1/MMBTU move in natural gas, and $20 million for a $10/ton shift in coal prices. AES merchant generation assets in New York, which are reflected in discontinued operations, are estimated to have pre-tax earnings exposure of $45 million for a $1/MMBTU move in natural gas and $15 million for a $10/ton shift in coal prices. Our estimates exclude correlation. For example, a decline in oil or natural gas prices can be accompanied by a decline in coal price if commodity prices are correlated. In aggregate, the Company s downside exposure occurs with lower oil, lower natural gas, and higher coal prices. Exposures at individual businesses will change as new contracts or financial hedges are executed.

Commodity prices affect our businesses differently depending on the local market characteristics and risk management strategies. Generation costs can be directly affected by movements in the price of natural gas, oil and coal. Spot power prices and contract indexation provisions are affected by these same commodity price movements. We have some natural offsets across our businesses such that low commodity prices may benefit certain businesses and be a cost to others. Offsets are not perfectly linear or symmetric. The sensitivities are affected by a number of non-market, or indirect market, factors. Examples of these factors include hydrology, energy market supply/demand balances, regional fuel supply issues, and regulatory interventions such as price caps. Operational flexibility changes the shape of our sensitivities. For instance, power plants may reduce dispatch in low market environments limiting downside exposure. Volume variation also affects our commodity exposure. The volume sold under contracts or retail concessions can vary based on weather and economic conditions resulting in a higher or lower volume of sales in spot markets. Thermal unit availability and hydrology can affect the generation output available for sale and can affect the marginal unit setting power prices.

In North America, IPL sells power at wholesale once retail demand is served, so retail sales demand may affect commodity exposure. Given that natural gas-fired generators set power prices for many markets, higher natural gas prices expand margins. The positive impact on margins will be moderated if natural gas-fired generators set the market price only during peak periods.

In Chile, we own assets and have associated contracts in both the central and northern regions of the country. Contracts tend to be long-term and indexed to fuel limiting commodity risk. Oil-fired generators set power prices for some markets impacting spot power margins. Gener has been adding coal-fired generation to its portfolio, increasing its exposure to dark spreads on un-hedged volumes. Gener also owns natural gas/diesel, hydropower and biomass generation facilities.

In other Latin American markets, the businesses have commodity exposure on un-hedged volumes. In Panama and Colombia, we own hydropower assets, so contracts are not indexed to fuel. In the Dominican Republic, we own natural gas-fired and coal-fired assets, and both contract and spot prices may move with commodity prices. In Argentina, prices are set according to government rules that result in commodity exposure based on the spread between cost of coal-fired generation and oil-fired generation and other factors.

In Europe, our Kilroot facility s long term PPA was terminated during the fourth quarter of 2010. The commodity risk at our Kilroot business is due to dark spread to the extent sales are un-hedged. Natural gas-fired generators set power prices for many periods, so higher natural gas prices expand margins and higher coal prices cause a decline. The positive impact on margins will be moderated if natural gas-fired generators set the market price only during certain peak periods.

Our Masinloc business in Asia is a coal-fired generation facility, which hedges its output through medium term contracts that are indexed to fuel prices. Low oil prices may be a driver of margin compression since oil affects spot power sale prices.

Foreign Exchange Rate Risk

In the normal course of business, we are exposed to foreign currency risk and other foreign operations risks that arise from investments in foreign subsidiaries and affiliates. A key component of these risks stems from the fact that some of our foreign subsidiaries and affiliates utilize currencies other than our consolidated reporting currency, the U.S. Dollar. Additionally, certain of our foreign subsidiaries and affiliates have entered into monetary obligations in the U.S. Dollar or currencies other than their own functional currencies. Primarily, we are exposed to changes in the exchange rate between the U.S. Dollar and the following currencies: Argentine Peso, Brazilian Real, British Pound, Cameroonian Franc, Chilean Peso, Colombian Peso, Euro, Kazakhstani Tenge, and Philippine Peso. These subsidiaries and affiliates have attempted to limit potential foreign exchange exposure by entering into revenue contracts that adjust to changes in foreign exchange rates. We also use foreign currency forwards, swaps and options, where possible, to manage our risk related to certain foreign currency fluctuations.

During the first quarter of 2011, we entered into hedges to partially mitigate the exposure of earnings translated into the U.S. Dollar to foreign exchange volatility. As of March 31, 2011, assuming a 10% U.S. Dollar appreciation, pre-tax earnings attributable to foreign subsidiaries exposed to movements in the exchange rates of the Brazilian Real, Argentine Peso, Philippine Peso and Euro (the earnings attributable to subsidiaries exposed to Cameroonian Franc movements are included under Euro due to the fixed exchange rate of the Cameroonian Franc to the Euro) relative to the U.S. Dollar are projected to be approximately $25 million, $10 million, $10 million, and $10 million, respectively, for the remainder of 2011 and represent the majority of the Company s pre-tax earnings exposure to currency moves. These numbers have been produced by applying a one-time 10% U.S. Dollar appreciation to forecasted exposed pre-tax earnings for the remainder of 2011 coming from subsidiaries where the local currency is either not the U.S. Dollar or is not exhibiting the characteristics of a peg or managed float relative to the U.S. Dollar, net of the impact of outstanding hedges and holding all other variables constant. The numbers presented above are net of any transactional gains/losses. These sensitivities may change in the future as new hedges are executed or existing hedges unwound. Additionally, updates to the forecasted pre-tax earnings exposed to foreign exchange risk may result in further modification.

Interest Rate Risks

We are exposed to risk resulting from changes in interest rates as a result of our issuance of variable and fixed-rate debt, as well as interest rate swap, cap and floor and option agreements.

Decisions on the fixed-floating debt ratio are made to be consistent with the risk factors faced by individual businesses or plants. Depending on whether a plant s capacity payments or revenue stream is fixed or varies with inflation, we partially hedge against interest rate fluctuations by arranging fixed-rate or variable-rate financing. In certain cases, particularly for non-recourse financing, we execute interest rate swap, cap and floor agreements to effectively fix or limit the interest rate exposure on the underlying financing.

As of March 31, 2011, the portfolio s pre-tax earnings exposure for the remainder of 2011 (adjusted to reflect noncontrolling interests) to a 100 basis point increase in Brazilian Real, British Pound, Colombian Peso, Euro, Philippine Peso, and U.S. Dollar interest rates would be approximately $20 million. This number is based on the impact of a one-time, 100 basis point increase in interest rates on interest expense for Brazilian Real, British Pound, Colombian Peso, Euro, Philippine Peso and U.S. Dollar-denominated debt, which is primarily non-recourse financing. The numbers do not take into account the historical correlation between these interest rates.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

The Company under the supervision and with the participation of its management, including the Company s Chief Executive Officer (CEO) and Chief Financial Officer (CFO), evaluated the effectiveness of its disclosure controls and procedures, as such term is defined in Rule 13a-15(e) under the Securities Act of 1934, as amended (the Exchange Act), as of the end of the period covered by this Quarterly Report on Form 10-Q. Based on that evaluation, our CEO and CFO have concluded that our disclosure controls and procedures were effective as of March 31, 2011 to ensure that information required to be disclosed by the Company in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and include controls and procedures designed to ensure that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Controls Over Financial Reporting

There were no changes that occurred during the fiscal quarter covered by this Quarterly Report on Form 10-Q that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II: OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The Company is involved in certain claims, suits and legal proceedings in the normal course of business, some of which are described Note 9 *Contingencies and Commitments* of the condensed consolidated financial statements included in Item 1. Financial Statements of this Form 10-Q. The Company has accrued for litigation and claims where it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. The Company believes, based upon information it currently possesses and taking into account established reserves for estimated liabilities and its insurance coverage, that the ultimate outcome of these proceedings and actions is unlikely to have a material adverse effect on the Company s financial statements. It is reasonably possible, however, that some matters could be decided unfavorably to the Company and could require the Company to pay damages or make expenditures in amounts that could be material but cannot be estimated as of March 31, 2011.

In 1989, Centrais Elétricas Brasileiras S.A. (Eletrobrás) filed suit in the Fifth District Court in the State of Rio de Janeiro against Eletropaulo Eletricidade de São Paulo S.A. (EEDSP) relating to the methodology for calculating monetary adjustments under the parties financing agreement. In April 1999, the Fifth District Court found for Eletrobrás and in September 2001, Eletrobrás initiated an execution suit in the Fifth District Court to collect approximately R$1.1 billion ($668 million) from Eletropaulo (as estimated by Eletropaulo) and a lesser amount from an unrelated company, Companhia de Transmissão de Energia Elétrica Paulista (CTEEP) (Eletropaulo and CTEEP were spun off from EEDSP pursuant to its privatization in 1998). In November 2002, the Fifth District Court rejected Eletropaulo s defenses in the execution suit. Eletropaulo appealed and in September 2003, the Appellate Court of the State of Rio de Janeiro (AC) ruled that Eletropaulo was not a proper party to the litigation because any alleged liability had been transferred to CTEEP pursuant to the privatization. In June 2006, the Superior Court of Justice (SCJ) reversed the Appellate Court s decision and remanded the case to the Fifth District Court for further proceedings, holding that Eletropaulo s liability, if any, should be determined by the Fifth District Court. Eletropaulo s subsequent appeals to the Special Court (the highest court within the SCJ) and the Supreme Court of Brazil were dismissed. Eletrobrás later requested that the amount of Eletropaulo s alleged debt be determined by an accounting expert appointed by the Fifth District Court. Eletropaulo consented to the appointment of such an expert, subject to a reservation of rights. In February 2010, the Fifth District Court appointed an accounting expert to determine the amount of the alleged debt and the responsibility for its payment in light of the privatization, in accordance with the methodology proposed by Eletrobrás. Pursuant to its reservation of rights, Eletropaulo filed an interlocutory appeal with the AC asserting that the expert was required to determine the issues in accordance with the methodology proposed by Eletropaulo, and that Eletropaulo should be entitled to take discovery and present arguments on the issues to be determined by the expert. In April 2010, the AC issued a decision agreeing with Eletropaulo s arguments and directing the Fifth District Court to proceed accordingly. Eletrobrás has restarted the accounting proceedings at the Fifth District Court, which will proceed in accordance with the AC s April 2010 decision. In the Fifth District Court proceedings, the expert s conclusions will be subject to the Fifth District Court s review and approval. If Eletropaulo is determined to be responsible for the debt, after the amount of the alleged debt is determined, Eletrobrás will be entitled to resume the execution suit in the Fifth District Court at any time. If Eletrobrás does so, Eletropaulo will be required to provide security in the amount of its alleged liability. In that case, if Eletrobrás requests the seizure of such security and the Fifth District Court grants such request, Eletropaulo s results of operations may be materially adversely affected, and in turn the Company s results of operations could be materially adversely affected. In addition, in February 2008, CTEEP filed a lawsuit in the Fifth District Court against Eletrobrás and Eletropaulo seeking a declaration that CTEEP is not liable for any debt under the financing agreement. The parties are disputing the proper venue for the CTEEP lawsuit. Eletropaulo believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In August 2000, the FERC announced an investigation into the organized California wholesale power markets to determine whether rates were just and reasonable. Further investigations involved alleged market manipulation. FERC requested documents from each of the AES Southland, LLC plants and AES Placerita, Inc. AES Southland and AES Placerita have cooperated fully with the FERC investigations. AES Southland was not subject to refund liability because it did not sell into the organized spot markets due to the nature of its tolling agreement. After hearings at FERC, AES Placerita was found subject to refund liability of $588,000 plus interest for spot sales to the California Power Exchange from October 2, 2000 to June 20, 2001. As FERC investigations and hearings progressed, numerous appeals on related issues were filed with the U.S. Court of Appeals for the Ninth Circuit. Over the years, the Ninth Circuit issued several opinions that had the potential to expand the scope of the FERC proceedings and increase refund exposure for AES Placerita and other sellers of electricity. Following remand of one of the Ninth Circuit appeals in March 2009, FERC started a new hearing process involving AES Placerita and other sellers. In May 2009, AES Placerita entered into a settlement, approved by FERC in July 2009, concerning the claims before FERC against AES Placerita relating to the California energy crisis of 2000-2001, including the California refund proceeding. Pursuant to the settlement, AES Placerita paid $6 million and assigned a receivable of $168,119 due to it from the California Power Exchange in return for a release of all claims against it at FERC by the settling parties and other consideration. More than 98% of the buyers in the market elected to join the settlement. A small amount of AES Placerita s settlement payment was placed in escrow for buyers that did not join the settlement (non-settling parties). It is unclear whether the escrowed funds will be enough to satisfy any additional sums that might be determined to be owed to non-settling parties at the conclusion of the FERC proceedings concerning the California energy crisis. However, any such additional sums are expected to be immaterial to the Company s consolidated financial statements. In November 2009, one non-settling party, the Sacramento Municipal Utility District (SMUD), filed an appeal of the FERC s approval of the settlement which is pending in the Ninth Circuit. SMUD s appeal has been stayed pending further order of the court. The settlement agreement is still effective and will continue to remain effective unless it is vacated by the Ninth Circuit. SMUD has reached a settlement in principal with buyers of electricity that, if approved by FERC, will leave only immaterial claims of non-settling parties against AES Placerita. As a consequence of SMUD s settlement, it will withdraw its appeal of the Placerita order. In March 2011, the FERC approved the sale of AES Placerita to an unaffiliated entity. Pursuant to the stock purchase agreement, certain AES affiliates agreed to indemnify the purchaser against losses related to the claims against AES Placerita in the FERC proceedings, which losses, if any, are expected to be immaterial to the Company s consolidated financial statements.

In August 2001, the Grid Corporation of Orissa, India, now Gridco Ltd. (Gridco), filed a petition against the Central Electricity Supply Company of Orissa Ltd. (CESCO), an affiliate of the Company, with the Orissa Electricity Regulatory Commission (OERC), alleging that CESCO had defaulted on its obligations as an OERC-licensed distribution company, that CESCO management abandoned the management of CESCO, and asking for interim measures of protection, including the appointment of an administrator to manage CESCO. Gridco, a state-owned entity, is the sole wholesale energy provider to CESCO. Pursuant to the OERC s August 2001 order, the management of CESCO was replaced with a government administrator who was appointed by the OERC. The OERC later held that the Company and other CESCO shareholders were not necessary or proper parties to the OERC proceeding. In August 2004, the OERC issued a notice to CESCO, the Company and others giving the recipients of the notice until November 2004 to show cause why CESCO s distribution license should not be revoked. In response, CESCO submitted a business plan to the OERC. In February 2005, the OERC issued an order rejecting the proposed business plan. The order also stated that the CESCO distribution license would be revoked if an acceptable business plan for CESCO was not submitted to and approved by the OERC prior to March 31, 2005. In its April 2, 2005 order, the OERC revoked the CESCO distribution license. CESCO has filed an appeal against the April 2, 2005 OERC order and that appeal remains pending in the Indian courts. In addition, Gridco asserted that a comfort letter issued by the Company in connection with the Company s indirect investment in CESCO obligates the Company to provide additional financial support to cover all of CESCO s financial obligations to Gridco. In December 2001, Gridco served a notice to arbitrate pursuant to the Indian Arbitration and Conciliation Act of 1996 on the Company, AES Orissa Distribution Private Limited (AES ODPL), and Jyoti Structures (Jyoti) pursuant to the terms of the CESCO Shareholders Agreement between Gridco, the Company, AES ODPL, Jyoti and CESCO (the CESCO arbitration). In the arbitration, Gridco appeared to be seeking approximately $189 million in damages, plus undisclosed penalties and interest, but a detailed alleged damage analysis was not filed by Gridco. The Company counterclaimed against Gridco for damages. In June 2007, a 2-to-1 majority of the arbitral tribunal rendered its award rejecting Gridco s claims and holding that none of the respondents, the Company, AES ODPL, or Jyoti, had any liability to Gridco. The respondents counterclaims were also rejected. In September 2007, Gridco

filed a challenge of the arbitration award with the local Indian court. In June 2008, Gridco filed a separate application with the local Indian court for an order enjoining the Company from selling or otherwise transferring its shares in Orissa Power Generation Corporation Ltd. s (OPGC), an equity method investment, and requiring the Company to provide security in the amount of the contested damages in the CESCO arbitration until Gridco s challenge to the arbitration award is resolved. In June 2010, a 2-to-1 majority of the arbitral tribunal awarded the Company some of its costs relating to the arbitration. In August 2010, Gridco filed a challenge of the cost award with the local Indian court. The Company believes that it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In early 2002, Gridco made an application to the OERC requesting that the OERC initiate proceedings regarding the terms of OPGC s existing PPA with Gridco. In response, OPGC filed a petition in the Indian courts to block any such OERC proceedings. In early 2005, the Orissa High Court upheld the OERC s jurisdiction to initiate such proceedings as requested by Gridco. OPGC appealed that High Court s decision to the Supreme Court and sought stays of both the High Court s decision and the underlying OERC proceedings regarding the PPAs terms. In April 2005, the Supreme Court granted OPGC s requests and ordered stays of the High Court s decision and the OERC proceedings with respect to the PPA s terms. The matter is awaiting further hearing. Unless the Supreme Court finds in favor of OPGC s appeal or otherwise prevents the OERC s proceedings regarding the PPA s terms, the OERC will likely lower the tariff payable to OPGC under the PPA, which would have an adverse impact on OPGC s financial condition and results of operations. OPGC believes that it has meritorious claims and defenses and will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In March 2003, the office of the Federal Public Prosecutor for the State of São Paulo, Brazil (MPF) notified AES Eletropaulo that it had commenced an inquiry related to the BNDES financings provided to AES Elpa and AES Transgás and the rationing loan provided to Eletropaulo, changes in the control of Eletropaulo, sales of assets by Eletropaulo and the quality of service provided by Eletropaulo to its customers, and requested various documents from Eletropaulo relating to these matters. In July 2004, the MPF filed a public civil lawsuit in the Federal Court of São Paulo (FSCP) alleging that BNDES violated Law 8429/92 (the Administrative Misconduct Act) and BNDES s internal rules by: (1) approving the AES Elpa and AES Transgás loans; (2) extending the payment terms on the AES Elpa and AES Transgás loans; (3) authorizing the sale of Eletropaulo s preferred shares at a stock-market auction; (4) accepting Eletropaulo s preferred shares to secure the loan provided to Eletropaulo; and (5) allowing the restructurings of Light Serviços de Eletricidade S.A. and Eletropaulo. The MPF also named AES Elpa and AES Transgás as defendants in the lawsuit because they allegedly benefited from BNDES s alleged violations. In May 2006, the FCSP ruled that the MPF could pursue its claims based on the first, second, and fourth alleged violations noted above. The MPF subsequently filed an interlocutory appeal with the Federal Court of Appeals (FCA) seeking to require the FCSP to consider all five alleged violations. Also, in July 2006, AES Elpa and AES Transgás filed an interlocutory appeal with the FCA, which was subsequently consolidated with the MPF s interlocutory appeal, seeking a transfer of venue and to enjoin the FCSP from considering any of the alleged violations. In June 2009, the FCA granted the injunction sought by AES Elpa and AES Transgás and transferred the case to the Federal Court of Rio de Janeiro. In May 2010, the MPF filed an appeal with the Superior Court of Justice challenging the transfer. The MPF s lawsuit before the FCSP has been stayed pending a final decision on the interlocutory appeals. AES Elpa and AES Brasiliana (the successor of AES Transgás) believe they have meritorious defenses to the allegations asserted against them and will defend themselves vigorously in these proceedings; however, there can be no assurances that they will be successful in their efforts.

AES Florestal, Ltd. (Florestal), had been operating a pole factory and had other assets, including a wooded area known as Horto Renner, in the State of Rio Grande do Sul, Brazil (collectively, Property).

Florestal had been under the control of AES Sul (Sul) since October 1997, when Sul was created pursuant to a privatization by the Government of the State of Rio Grande do Sul. After it came under the control of Sul, Florestal performed an environmental audit of the entire operational cycle at the pole factory. The audit discovered 200 barrels of solid creosote waste and other contaminants at the pole factory. The audit concluded that the prior operator of the pole factory, Companhia Estadual de Energia Elétrica (CEEE), had been using those contaminants to treat the poles that were manufactured at the factory. Sul and Florestal subsequently took the initiative of communicating with Brazilian authorities, as well as CEEE, about the adoption of containment and remediation measures. The Public Attorney s Office has initiated a civil inquiry (Civil Inquiry n. 24/05) to investigate potential civil liability and has requested that the police station of Triunfo institute a police investigation (IP number 1041/05) to investigate potential criminal liability regarding the contamination at the pole factory. The parties filed defenses in response to the civil inquiry. The Public Attorney s Office then requested an injunction which the judge rejected on September 26, 2008. The Public Attorney s office has a right to appeal the decision. The environmental agency (FEPAM) has also started a procedure (Procedure n. 088200567/059) to analyze the measures that shall be taken to contain and remediate the contamination. Also, in March 2000, Sul filed suit against CEEE in the 2nd Court of Public Treasure of Porto Alegre seeking to register in Sul s name the Property that it acquired through the privatization but that remained registered in CEEE s name. During those proceedings, AES subsequently waived its claim to re-register the Property and asserted a claim to recover the amounts paid for the Property. That claim is pending. In November 2005, the 7th Court of Public Treasure of Porto Alegre ruled that the Property must be returned to CEEE. CEEE has had sole possession of Horto Renner since September 2006 and of the rest of the Property since April 2006. In February 2008, Sul and CEEE signed a Technical Cooperation Protocol pursuant to which they requested a new deadline from FEPAM in order to present a proposal. In March 2008, the State Prosecution office filed a Public Class Action against AES Florestal, AES Sul and CEEE, requiring an injunction for the removal of the alleged sources of contamination and the payment of an indemnity in the amount of R$6 million ($4 million). The injunction was rejected and the case is in the evidentiary state awaiting the judge s determination as to who will serve as the court- appointed expert with responsibility for producing the expert evidence. The above-referenced proposal was delivered on April 8, 2008. FEPAM responded by indicating that the parties should undertake the first step of the proposal which would be to retain a contractor. In its response, Sul indicated that such step should be undertaken by CEEE as the relevant environmental events resulted from CEEE s operations. It is estimated that remediation could cost approximately R$14.7 million ($9 million). Discussions between Sul and CEEE are ongoing.

In January 2004, the Company received notice of a Formulation of Charges filed against the Company by the Superintendence of Electricity of the Dominican Republic. In the Formulation of Charges, the Superintendence asserts that the existence of three generation companies (Empresa Generadora de Electricidad Itabo, S.A. (Itabo), Dominican Power Partners, and AES Andres BV) and one distribution company (Empresa Distribuidora de Electricidad del Este, S.A. (Este)) in the Dominican Republic, violates certain cross-ownership restrictions contained in the General Electricity Law of the Dominican Republic. In February 2004, the Company filed in the First Instance Court of the National District of the Dominican Republic an action seeking injunctive relief based on several constitutional due process violations contained in the Formulation of Charges (Constitutional Injunction). In February 2004, the Court granted the Constitutional Injunction and ordered the immediate cessation of any effects of the Formulation of Charges, and the enactment by the Superintendence of Electricity of a special procedure to prosecute alleged antitrust complaints under the General Electricity Law. In March 2004, the Superintendence of Electricity appealed the Court s decision. In July 2004, the Company divested any interest in Este. The Superintendence of Electricity s appeal is pending. The Company believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In July 2004, the Corporación Dominicana de Empresas Eléctricas Estatales (CDEEE) filed lawsuits against Itabo, an affiliate of the Company, in the First and Fifth Chambers of the Civil and Commercial Court of First Instance for the National District. CDEEE alleges in both lawsuits that Itabo spent more than was necessary to rehabilitate two generation units of an Itabo power plant and, in the Fifth Chamber lawsuit, that those funds were paid to affiliates and subsidiaries of AES Gener and Coastal Itabo, Ltd. (Coastal), a former shareholder of Itabo, without the required approval of Itabo s board of administration. In the First Chamber lawsuit, CDEEE seeks an accounting of Itabo s transactions relating to the rehabilitation. In November 2004, the First Chamber dismissed the case for lack of legal basis. On appeal, in October 2005 the Court of Appeals of Santo Domingo ruled in Itabo s favor, reasoning that it lacked jurisdiction over the dispute because the parties contracts mandated arbitration. The Supreme Court of Justice is considering CDEEE s appeal of the Court of Appeals decision. In the Fifth Chamber lawsuit, which also names Itabo s former president as a defendant, CDEEE seeks $15 million in damages and the seizure of Itabo s assets. In October 2005, the Fifth Chamber held that it lacked jurisdiction to adjudicate the dispute given the arbitration provisions in the parties contracts. The First Chamber of the Court of Appeal ratified that decision in September 2006. In a related proceeding, in May 2005, Itabo filed a lawsuit in the U.S. District Court for the Southern District of New York seeking to compel CDEEE to arbitrate its claims. The petition was denied in July 2005. Itabo s appeal of that decision to the U.S. Court of Appeals for the Second Circuit has been stayed since September 2006. Further, in September 2006, in an International Chamber of Commerce arbitration, an arbitral tribunal determined that it lacked jurisdiction to decide arbitration claims concerning these disputes. Itabo believes it has meritorious claims and defenses and will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In July 2007, the Competition Committee of the Ministry of Industry and Trade of the Republic of Kazakhstan (the Competition Committee) ordered Nurenergoservice, an AES subsidiary, to pay approximately KZT 18 billion ($122 million) for alleged antimonopoly violations in 2005 through the first quarter of 2007. The Competition Committee s order was affirmed by the economic court in April 2008 (April 2008 Decision). The economic court also issued an injunction to secure Nurenergoservice s alleged liability, freezing Nurenergoservice s bank accounts and prohibiting Nurenergoservice from transferring or disposing of its property. Nurenergoservice s subsequent appeals to the court of appeals were rejected. In February 2009, the Antimonopoly Agency (the Competition Committee s successor) seized approximately KZT 778 million ($5 million) from a frozen Nurenergoservice bank account in partial satisfaction of Nurenergoservice s alleged damages liability. However, on appeal to the Kazakhstan Supreme Court, in October 2009, the Supreme Court annulled the decisions of the lower courts because of procedural irregularities and remanded the case to the economic court for reconsideration. On remand, in January 2010, the economic court reaffirmed its April 2008 Decision. Nurenergoservice s appeals in the court of appeals (first panel) and the court of appeals (second panel) were unsuccessful. Nurenergoservice intends to file a further appeal to the Kazakhstan Supreme Court. In separate but related proceedings, in August 2007, the Competition Committee ordered Nurenergoservice to pay approximately KZT 1.8 billion ($12 million) in administrative fines for its alleged antimonopoly violations. Nurenergoservice s appeal to the administrative court was rejected in February 2009. Given the adverse court decisions against Nurenergoservice, the Antimonopoly Agency may attempt to seize Nurenergoservice s remaining assets, which are immaterial to the Company s consolidated financial statements. The Antimonopoly Agency has not indicated whether it intends to assert claims against Nurenergoservice for alleged antimonopoly violations post first quarter 2007. Nurenergoservice believes it has meritorious defenses to the claims asserted against it; however, there can be no assurances that it will prevail in these proceedings.

In April 2009, the Antimonopoly Agency initiated an investigation of the power sales of Ust-Kamenogorsk HPP (UK HPP) and Shulbinsk HPP, hydroelectric plants under AES concession (collectively, the Hydros), in January through February 2009. The investigation of both Hydros has now been completed. The Antimonopoly Agency determined that the Hydros abused their market position and charged monopolistically high prices for power in January through February 2009. The Agency sought an order from the administrative court requiring UK HPP to pay an administrative fine of approximately KZT 120 million ($1 million) and to disgorge profits for the period at issue, estimated by the Antimonopoly Agency to be approximately KZT 440 million ($3 million). No fines or damages have been paid to date, however, as the proceedings in the administrative court have been suspended due to the initiation of related criminal proceedings against officials of the Hydros. In the course of criminal proceedings, the financial police have expanded the periods at issue to the entirety of 2009 in the case of UK HPP and from January through October 2009 in the case of Shulbinsk HPP, and sought increased damages of KZT 1.2 billion ($8 million) in the case of UK HPP and KZT 1.3 billion

($9 million) in the case of Shulbinsk HPP. The Hydros believe they have meritorious defenses and will assert them vigorously in these proceedings; however, there can be no assurances that they will be successful in their efforts.

In April 2009, the Antimonopoly Agency initiated an investigation of Ust-Kamenogorsk TETS LLP s (UKT) power sales in 2008 through February 2009. The Antimonopoly Agency subsequently concluded that UKT abused its market position and charged monopolistically high prices for power and should pay an administrative fine of approximately KZT 136 million ($1 million). The Antimonopoly Agency later sought an order from the administrative court requiring UKT to pay the fine. The administrative court proceedings have been suspended pending the outcome of a related criminal investigation of UKT employees. However, the criminal investigation was terminated and the Antimonopoly Agency thereafter resumed the administrative proceedings. If the Antimonopoly Agency prevails in the administrative proceedings, UKT may be ordered to pay the administrative fine and disgorge the profits from the sales at issue, estimated by the Antimonopoly Agency to be approximately 514 million KZT ($3 million). UKT believes it has meritorious defenses and will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska, filed a complaint in the U.S. District Court for the Northern District of California against the Company and numerous unrelated companies, claiming that the defendants alleged GHG emissions have contributed to alleged global warming which, in turn, allegedly has led to the erosion of the plaintiffs alleged land. The plaintiffs assert nuisance and concert of action claims against the Company and the other defendants, and a conspiracy claim against a subset of the other defendants. The plaintiffs seek to recover relocation costs, indicated in the complaint to be from $95 million to $400 million, and other unspecified damages from the defendants. The Company filed a motion to dismiss the case, which the District Court granted in October 2009. The plaintiffs have appealed to the U.S. Court of Appeals for the Ninth Circuit. The parties have briefed the appeal and are awaiting a date for oral argument. The Company believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In July, 1993 the Public Attorney s office filed a claim against Eletropaulo, the Sao Paulo State Government, SABESP (a state-owned company), CETESB (a state-owned company) and DAEE (the municipal Water and Electric Energy Department) alleging that they were liable for pollution of the Billings Reservoir as a result of pumping water from the Pinheiros River into the Billings Reservoir. The events in question occurred while Eletropaulo was a state-owned company. An initial lower court decision in 2007 found the parties liable for the payment of approximately R$670 million ($407 million) for remediation. Eletropaulo subsequently appealed the decision to the Appellate Court of the State of Sao Paulo which reversed the lower court decision. In 2009, the Public Attorney s Office has filed appeals to both Superior Court of Justice (SCJ) and the Supreme Court (SC) and such appeals were answered by Eletropaulo in the fourth quarter of 2009. Eletropaulo believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In September 1996, a public civil action was asserted against Eletropaulo and Associação Desportiva Cultural Eletropaulo (the Associação) relating to alleged environmental damage caused by construction of the Associação near Guarapiranga Reservoir. The initial decision that was upheld by the Appellate Court of the State of Sao Paulo in 2006 found that Eletropaulo should repair the alleged environmental damage by demolishing certain construction and reforesting the area, and either sponsor an environmental project which would cost approximately R$1 million ($607 thousand) as of December 31, 2010, or pay an indemnification amount of approximately R$10 million ($6 million). Eletropaulo has appealed this decision to the Supreme Court and is awaiting a decision.

In February 2009, a CAA Section 114 information request from the EPA regarding Cayuga and Somerset was received. The request seeks various operating and testing data and other information regarding certain types of projects at the Cayuga and Somerset facilities, generally for the time period from January 1, 2000 through the date of the information request. This type of information request has been used in the past to assist the EPA in determining whether a plant is in compliance with applicable standards under the CAA. Cayuga and Somerset responded to the EPA s information request in June 2009, and they are awaiting a response from the EPA regarding their submittal. At this time, it is not possible to predict what impact, if any, this request may have on the Company, its results of operations or its financial position.

On February 2, 2009, the Cayuga facility received a Notice of Violation from the New York State Department of Environmental Conservation (NYSDEC) that the facility had exceeded the permitted volume limit of coal ash that can be disposed of in the on-site landfill. Cayuga has met with NYSDEC and submitted a Landfill Liner Demonstration Report to them. Such report found that the landfill has adequate engineering integrity to support the additional coal ash and there is no inherent environmental threat. NYSDEC has indicated they accept the finding of the report. A permit modification was approved by the NYSDEC on May 14, 2010 and such permit modification allows for closure of this approximately 10-acre portion of the landfill. The construction in accordance with the approved permit modification was completed in November 2010 and the certification report for this construction project is currently being drafted to submit to the NYSDEC in the second quarter of 2011. While at this time it is not possible to predict what impact, if any, this matter may have on the Company, its results of operations or its financial position, based upon the discussions to date, the Company does not believe the impact will be material.

In March 2009, AES Uruguaiana Empreendimentos S.A. (AESU) initiated arbitration in the International Chamber of Commerce (ICC) against YPF S.A. (YPF) seeking damages and other relief relating to YPF s breach of the parties gas supply agreement (GSA). Thereafter, in April 2009, YPF initiated arbitration in the ICC against AESU and two unrelated parties, Companhia de Gas do Esado do Rio Grande do Sul and Transportador de Gas del Mercosur S.A. (TGM), claiming that AESU wrongfully terminated the GSA and caused the termination of a transportation agreement (TA) between YPF and TGM (YPF Arbitration). YPF seeks an unspecified amount of damages from AESU, a declaration that YPF s performance was excused under the GSA due to certain alleged force majeure events, or, in the alternative, a declaration that the GSA and the TA should be terminated without a finding of liability against YPF because of the allegedly onerous obligations imposed on YPF by those agreements. In addition, in the YPF Arbitration, TGM asserts that if it is determined that AESU is responsible for the termination of the GSA, AESU is liable for TGM s alleged losses, including losses under the TA. In April 2011, the arbitrations were consolidated into a single proceeding, and a new procedural schedule was established for the consolidated proceeding. The hearing on liability issues will take place in December 2011. AESU believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously; however, there can be no assurances that it will be successful in its efforts.

In June 2009, the Inter-American Commission on Human Rights of the Organization of American States (IACHR) requested that the Republic of Panama suspend the construction of AES Changuinola S.A. s hydroelectric project (Project) until the bodies of the Inter-American human rights system can issue a final decision on a petition (286/08) claiming that the construction violates the human rights of alleged indigenous communities. In July 2009, Panama responded by informing the IACHR that it would not suspend construction of the Project and requesting that the IACHR revoke its request. In June 2010, the Inter-American Court of Human Rights vacated the IACHR s request. With respect to the merits of the underlying petition, the IACHR heard arguments by the communities and Panama in November 2009, but has not issued a decision to date. The Company cannot predict Panama s response to any determination on the merits of the petition by the bodies of the Inter-American human rights system.

In July 2009, AES Energía Cartagena S.R.L. (AES Cartagena) received notices from the Spanish national energy regulator, Comisión Nacional de Energía (CNE), stating that the proceeds of the sale of electricity from AES Cartagena s plant should be reduced by roughly the value of the CO_2 allowances that were granted to AES Cartagena for free for the years 2007, 2008, and the first half of 2009. In particular, the notices stated that CNE intended to invoice AES Cartagena to recover that value, which CNE calculated as approximately 20 million

($28 million) for 2007-2008 and an amount to be determined for the first half of 2009. In September 2009, AES Cartagena received invoices for 523,548 (approximately $738,000) for the allowances granted for free for 2007 and 19,907,248 (approximately $28 million) for 2008. In July 2010, AES Cartagena received an invoice for approximately 5 million ($7 million) for the allowances granted for free for the first half of 2009. AES Cartagena does not expect to be charged for CO_2 allowances issued free of charge for subsequent periods. AES Cartagena has paid the amounts invoiced and has filed challenges to the CNE s demands in the Spanish judicial system. There can be no assurances that the challenges will be successful. AES Cartagena has demanded indemnification from its fuel supply and electricity toller, GDF-Suez, in relation to the CNE invoices under the long-term energy agreement (the Energy Agreement) with GDF-Suez. However, GDF-Suez has disputed that it is responsible for the CNE invoices under the Energy Agreement. Therefore, in September 2009, AES Cartagena initiated arbitration against GDF-Suez, seeking to recover the payments made to CNE. In the arbitration, AES Cartagena also seeks a determination that GDF-Suez is responsible for procuring and bearing the cost of CO_2 allowances that are required to offset the CO_2 emissions of AES Cartagena s power plant, which is also in dispute between the parties. To date, AES Cartagena has paid approximately 25 million ($35 million) for the CO_2 allowances that have been required to offset 2008, 2009 and 2010 CO_2 emissions. AES Cartagena expects that allowances will need to be purchased to offset emissions for subsequent years. The evidentiary hearing in the arbitration took place from May 31-June 4, 2010, and closing arguments were heard on September 1, 2010. In February 2011, the arbitral tribunal requested further briefing on certain issues in the arbitration, which was later submitted by the parties. The tribunal has the matter under consideration. If AES Cartagena does not prevail in the arbitration and is required to bear the cost of carbon compliance, its results of operations could be materially adversely affected and, in turn, there could be a material adverse effect on the Company and its results of operations. AES Cartagena believes it has meritorious claims and will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In September 2009, the Public Defender s Office of the State of Rio Grande do Sul (PDO) filed a class action against AES Sul in the 16th District Court of Porto Alegre, Rio Grande do Sul (District Court), claiming that AES Sul has been illegally passing PIS and COFINS taxes (taxes based on AES Sul s income) to consumers. According to ANEEL s Order No. 93/05, the federal laws of Brazil, and the Brazilian Constitution, energy companies such as AES Sul are entitled to highlight PIS and COFINS taxes in power bills to final consumers, as the cost of those taxes is included in the energy tariffs that are applicable to final consumers. Before AES Sul had been served with the action, the District Court dismissed the lawsuit in October 2009 on the ground that AES Sul had been properly highlighting PIS and COFINS taxes in consumer bills in accordance with Brazilian law. In April 2010, the PDO appealed to the Appellate Court of the State of Rio Grande do Sul (AC). In November 2010, the AC affirmed the dismissal. The PDO did not appeal, and the District Court s decision became final and unappealable in March 2011.

In October 2009, IPL received a Notice of Violation (NOV) and Finding of Violation from EPA pursuant to CAA Section 113(a). The NOV alleges violations of the CAA at IPL s three coal-fired electric generating facilities dating back to 1986. The alleged violations primarily pertain to EPA s Prevention of Significant Deterioration and nonattainment New Source Review (NSR) requirements under the CAA. Since receiving the letter, IPL management has met with EPA staff and is currently in discussions with the EPA regarding possible resolutions to this NOV. At this time, we cannot predict the ultimate resolution of this matter. However, settlements and litigated outcomes of similar cases have required companies to pay civil penalties and to install additional pollution control technology on coal-fired electric generating units. A similar outcome in this case could have a material impact to IPL and could, in turn, have a material impact on the Company. IPL would seek recovery through customer rates of any operating or capital expenditures related to pollution control technology systems to reduce regulated air emissions; however, there can be no assurances that it would be successful in that regard.

In November 2009, April 2010, December 2010, and April 2011, substantially similar personal injury lawsuits were filed by a total of 41 residents and estates in the Dominican Republic against the Company, AES Atlantis, Inc., AES Puerto Rico, LP, AES Puerto Rico, Inc., and AES Puerto Rico Services, Inc., in the Superior

Court for the State of Delaware. In each lawsuit the plaintiffs allege that the coal combustion byproducts of AES Puerto Rico s power plant were illegally placed in the Dominican Republic in October 2003 through March 2004 and subsequently caused the plaintiffs birth defects, other personal injuries, and/or deaths. The plaintiffs do not quantify their alleged damages, but generally allege that they are entitled to compensatory and punitive damages. The AES defendants have moved for partial dismissal of both the November 2009 and April 2010 lawsuits on various grounds. (By agreement with the plaintiffs, the AES defendants have not yet responded to the December 2010 or April 2011 lawsuits, and will not do so until after the Superior Court rules on the pending partial dismissal motions in the other cases.) In September 2010, the Superior Court heard arguments on the motions. The Superior Court dismissed the plaintiffs fraud allegations without prejudice to replead, and the plaintiffs filed amended complaints in November 2010. The AES defendants have filed a renewed motion to dismiss the amended issues. A ruling on that motion is pending. Also, a ruling on the remaining claims (other than fraud) addressed in the original partial dismissal motions is still pending. The AES defendants believe they have meritorious defenses to the claims asserted against them and will defend themselves vigorously; however, there can be no assurances that they will be successful in their efforts.

On December 21, 2010, AES-3C Maritza East 1 EOOD, which owns an unfinished 670 MW lignite-fired power plant in Bulgaria, made the first in a series of demands on the performance bond securing the construction Contractor s obligations under the parties EPC Contract. The Contractor failed to complete the plant on schedule. The total amount demanded by Maritza under the performance bond is approximately 155 million ($219 million). However, the Contractor has obtained an injunction from a French court purportedly preventing the issuing bank from honoring the bond demands. Maritza is seeking relief in the French and English courts to attempt to lift that injunction or otherwise obtain payment on its demands. In addition, in December 2010, the Contractor issued a notice of dispute alleging that the lignite that has been supplied by Maritza for commissioning of the power plant is out of specification, allegedly entitling the Contractor to an extension of time to complete the power plant, an increase to the contract price of approximately 62 million ($87 million), and other relief. The Contractor thereafter advised Maritza that it had stopped commissioning of the power plant s two units because of the characteristics of the lignite supplied, and, in January 2011, initiated arbitration on its lignite claim. The Contractor later added claims seeking further extensions of time and an additional 10 million ($14 million) relating to the alleged unavailability of the grid during commissioning. Maritza has rejected the Contractor s claims and asserted counterclaims for delay liquidated damages and other relief relating to the Contractor s failure to complete the power plant and other breaches of the EPC contract. Maritza has also terminated the construction contract for cause and asserted arbitration claims against the Contractor relating to the termination. Maritza believes it has meritorious claims and defenses and will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

On February 11, 2011 AES Eletropaulo received a notice of violation from São Paulo State s Environmental Authorities for allegedly destroying 0.32119 hectares of native vegetation at the Conservation Park of Serra do Mar (Park), without previous authorization or license. The notice of violation asserted a fine of approximately R$1 ($635,265) and the suspension of AES Eletropaulo activities in the Park. As a response to this administrative procedure before the São Paulo State Environmental Authorities, AES Eletropaulo timely presented its defense on February 28, 2011 seeking to vacate the notice of violation or reduce the fine. A decision in this administrative procedure is expected to be issued in 2012.

In April 2011, Empresa Distribuidora de Electricidad del Este, S.A. (EDE Este), a distribution company of the Government of the Dominican Republic, initiated arbitration proceedings in the Centro de Resolución Alternativa de Controversias de la Cámara de Comercio y Producción de Santo Domingo (Dominican Arbitral Center) against AES Andrés, B.V. (AES Andrés), seeking a declaration that AES Andrés must deliver an additional 250 MWs under the parties long-term power purchase agreement (PPA) and damages relating to AES Andrés alleged refusal to supply the additional capacity. EDE Este also sought and obtained an ex-parte injunction from the Dominican courts requiring AES Andrés to deliver the additional 250 MWs and preventing AES Andrés from providing such additional capacity to any other third party. AES Andrés thereafter initiated arbitration against EDE Este in the ICC seeking, among other things, a declaratory judgment confirming that

EDE Este is not entitled to the additional capacity, an order suspending the PPA given EDE Este s continued failure to pay AES Andrés invoices on time for the 50 MWs of capacity contracted under the PPA, and damages resulting from EDE Este s breach of the PPA. AES Andrés also intends to challenge the jurisdiction of the Dominican Arbitral Center to determine the merits of this dispute, and to attempt to lift the ex-parte injunction. Further, AES Andrés has notified its other customers that it will not be obligated to deliver power to them if the ex-parte injunction is enforced. At this time, AES Andrés cannot estimate its potential losses relating to these matters. However, if it is unsuccessful, it is possible that Andrés results of operations could be materially adversely affected. AES Andrés believes it has meritorious claims and defenses, which it will assert vigorously in these proceedings; however, there can be no assurances it will be successful in its efforts.

ITEM 1A. RISK FACTORS

Other than those described below, there have been no material changes to the risk factors as previously disclosed in our 2010 Form 10-K.

Failure to complete the purchase of DPL, Inc. could negatively impact our stock price and future business and financial results.

On April 20, 2011, the Company announced the execution of an Agreement and Plan of Merger (the Merger Agreement) with DPL Inc. (DPL), the parent company of Dayton Power & Light Company, a utility company based in Ohio. The Merger Agreement with DPL contains a number of important conditions that must be satisfied before we can complete the transaction, including, without limitation, certain conditions that may be outside of our control relating to: (i) approval of the transaction by the DPL shareholders, (ii) receipt of required regulatory approvals, and (iii) our ability to prevail in certain lawsuits seeking to enjoin the merger. There can be no certainty, nor can we provide any assurance, that these conditions will be satisfied or, if satisfied, when they will be satisfied. The Merger Agreement contains certain termination rights for DPL and AES and further provides that, if DPL terminates the Merger Agreement prior to DPL shareholder approval in order to pursue a superior offer, DPL is required to pay AES a termination fee of $106 million (or $53 million if DPL terminates the Merger Agreement within 45 days after its execution in order to pursue a superior offer with a party that presents its offer within 30 days of the execution of the Merger Agreement. If the transaction is not completed, the market price of our common shares may decline.

In addition, whether or not the transaction is completed, the pending transaction could adversely affect our operations because matters relating to the transaction (including post-closing planning and certain litigation referenced in the DPL litigation risk factor set forth below) require substantial commitments of time, resources, and certain expenses by our management and employees, whether or not the transaction is completed, which could otherwise have been devoted to other opportunities beneficial to us.

We cannot guarantee when, or whether, the transaction will be completed, that there will not be a delay in the completion of the transaction or that all or any of the anticipated benefits of the transaction will be obtained. If the transaction is not completed or is delayed, we may experience the risks discussed above which may adversely affect our business, financial results and stock price.

In order to complete the acquisition of DPL, the Company and DPL must obtain certain governmental approvals, and if such approvals are not granted or are granted with conditions that become applicable to the parties, the completion of the transaction may be jeopardized or the anticipated benefits of the transaction could be reduced or materially impacted.

Completion of the acquisition of DPL is conditioned upon the receipt of certain governmental clearances or approvals, including, but not limited to, the Public Utilities Commission of Ohio, FERC, the expiration or termination of the applicable waiting period relating to the transaction under the Hart-Scott Rodino Act, and the Vermont Department of Banking. Although the Company and DPL have agreed in the Merger Agreement to use their reasonable best efforts to obtain the requisite governmental approvals, there can be no assurance that these approvals will be obtained. In addition, the governmental authorities from which these approvals are required have broad discretion in administering the governing regulations. As a condition to approval of the acquisition, these governmental authorities may impose requirements, limitations or costs or require divestitures or place restrictions on the conduct of our business or the business of the combined company after the completion of the acquisition. If either the Company or DPL becomes subject to any term, condition, obligation or restriction the imposition of such term, condition, obligation or restriction could adversely affect the ability to integrate DPL s operations into the Company s portfolio of businesses, reduce the anticipated benefits of the transaction or otherwise adversely affect the Company s business and results of operations after the completion of the acquisition.

A delay in the completion of the of the transaction beyond the termination date specified in the Merger Agreement due to, among other things, failure to obtain the required regulatory approvals, could provide either party with the right to terminate the Merger Agreement.

The Company is also subject to the risk that one or more required conditions to the transaction may not be satisfied. Both the Company and DPL are targeting to complete the transaction in the next six to nine months, but are subject to uncertainties related to this timing such that the closing may be delayed beyond this anticipated timeframe or may not occur at all.

Failure to complete the acquisition of DPL could negatively impact the stock price and the future business and financial results of the Company.

If the DPL transaction is not completed, the ongoing business of the Company may be adversely affected and, without realizing any of the benefits of having completed the acquisition, the Company would be subject to a number of risks, including the following:

- the Company may experience negative reactions from the financial markets, including credit rating agencies, and from its customers and employees;

- the Company will be required to pay certain costs relating to the acquisition, whether or not the transaction is completed; and

- matters relating to the transaction (including integration planning) will require substantial commitments of time and resources by the Company management, which would otherwise have been devoted to day-to-day operations, and other opportunities that may have been beneficial to the Company.

There can be no assurance that the risks described above will not materialize, and if any of them do, they may adversely affect the Company s business, financial results and stock price.

In addition, the Company could be subject to litigation related to any failure to complete the transaction or related to any enforcement proceeding commenced against the Company to perform its obligations under the Merger Agreement. If the transaction is not completed, these risks may materialize and may adversely affect the Company s business, financial results and stock price.

We are obligated to consummate the transaction with DPL whether or not we are able to obtain financing subject to limited exceptions.

Under the Merger Agreement we are generally obligated to consummate the transaction whether or not we are able to obtain financing. While we have entered into a commitment letter with Banc of America pursuant to which they have committed to provide financing under senior secured facilities aggregating up to $3.3 billion, their commitment is subject to the conditions contained therein. Accordingly, we cannot assure you that such financing will be available upon acceptable terms or at all.

Lawsuits have been and additional lawsuits may be filed against DPL and the Company challenging the acquisition, and an adverse ruling in any such lawsuit may prevent the transaction from being completed.

One of the conditions to the closing of the transaction is that no judgment, injunction, order or decree shall be in effect that prohibits the completion of the transaction. Certain lawsuits have been filed seeking to enjoin completion of the transaction. Accordingly, if a plaintiff is successful in obtaining an injunction prohibiting the completion of the acquisition, then such injunction may prevent the transaction from becoming effective, or from becoming effective within the expected timeframe.

After completion of the acquisition, the Company may fail to realize the anticipated benefits and cost savings of the acquisition, which could adversely affect the value of the Company s common stock.

The success of the transaction will depend, in part, on the Company s ability to realize the anticipated benefits and cost savings from integrating DPL into our portfolio of businesses. The ability of the Company to realize these anticipated benefits and cost savings is subject to certain risks including:

- the Company s ability to successfully combine the businesses of the Company and DPL into its portfolio;
- whether DPL will perform as expected;
- the possibility that the Company paid more than the value it will derive from the acquisition;
- the reduction of the Company s cash available for operations and other uses, the increase in amortization expense related to identifiable assets acquired and the incurrence of indebtedness to finance the acquisition; and
- the assumption of certain known and unknown liabilities of DPL.

If the Company is not able to successfully integrate DPL into its portfolio of businesses within the anticipated time frame, or at all, the anticipated benefits and cost savings of the transaction may not be realized fully or at all or may take longer to realize than expected, or DPL may not perform as expected. In addition, DPL may fail to perform as expected for reasons unrelated to the transaction. Many of the risks facing DPL are similar to the risks facing our other regulated utility businesses, including with respect to rate regulation (under the laws of Ohio), increased costs due to energy efficiency requirements and other environmental and health and safety regulations, volatility of fuels costs, increased benefit plan costs and exposure to environmental liabilities. DPL also faces unique risks, including increased competition as a result of Ohio legislation that permits its customers to select alternative electric generation service providers. Greater than expected customer switching would decrease DPL s revenues and increase its costs thereby causing its financial performance to be worse than the Company projected. Failure by DPL to perform as expected for any reason could adversely affect the Company s business, financial results and stock price.

The Company and DPL have operated and, until the completion of the acquisition, will continue to operate, independently. It is possible that the integration process could result in the loss of key DPL employees, the disruption of DPL s ongoing businesses, unexpected integration issues, higher than expected integration costs or an overall post-closing integration process that takes longer than originally anticipated.

In addition, at times, the attention of certain members of the Company s and DPL s management and resources may be focused on the completion of the transaction and the integration of the businesses of the two companies and diverted from day-to-day business operations, which may disrupt each of the companies ongoing business and the business of the combined company.

DPL may have difficulty attracting, motivating and retaining executives and other key employees in light of the acquisition.

Uncertainty about the effect of the transaction on DPL employees may have an adverse effect on DPL and consequently the combined business. This uncertainty may impair the Company s and DPL s ability to attract, retain

and motivate key personnel until the transaction is completed. Employee retention may be particularly challenging during the pendency of the transaction, as employees of DPL may experience uncertainty about their future roles in light of the transaction. Additionally, DPL s officers and employees may own shares of DPL s common stock and/or have vested stock option grants and, if the transaction is completed, may therefore be entitled to certain consideration, the payment of which could provide sufficient financial incentive for certain officers and employees to no longer pursue employment with the business. If key employees of DPL depart because of issues relating to the uncertainty and difficulty of integration, financial incentives or a desire not to remain employees of DPL, the Company may have to incur significant costs in identifying, hiring and retaining replacements for departing employees, which could reduce the Company s ability to realize the anticipated benefits of the acquisition.

The Company will incur significant transaction and acquisition-related costs in connection with the acquisition.

The Company expects to incur a number of non-recurring costs associated with combining the operations of the two companies. The substantial majority of non-recurring expenses resulting from the transaction will be comprised of transaction costs related to the acquisition, facilities and systems consolidation costs and employment-related costs. The Company will also incur transaction fees and costs related to formulating and implementing integration plans. The Company continues to assess the magnitude of these costs and additional unanticipated costs may be incurred in the integration of the two companies businesses. Although the Company expects that the elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, should allow the Company to offset incremental transaction and acquisition-related costs over time, this net benefit may not be achieved in the near term, or at all.

The transaction may not be accretive, and may be dilutive, to the Company s earnings per share and credit position, which may negatively affect the market price of the Company s common stock.

The Company currently anticipates that the transaction will be accretive to adjusted earnings per share beginning in the first year after closing. This expectation is based on preliminary estimates that may materially change. In addition, future events and conditions, including adverse changes in market conditions, additional transaction and integration related costs and other factors such as the failure to realize all of the benefits anticipated in the acquisition, could decrease or delay the accretion that is currently expected or could result in dilution. Any dilution of, or decrease or delay of any currently expected accretion to, the Company s earnings per share or cash flow could cause the price of the Company s common stock to decline and adversely affect its credit position. In addition, the Company intends to fund the acquisition through the issuance of additional debt aggregating approximately $3.3 billion. If incremental cash flow and dividends from operating subsidiaries of DPL are not sufficient to service this additional debt, the transaction could be credit dilutive to DPL and The AES Corporation, which may decrease the Company s financial flexibility and increase its borrowing costs, which could adversely affect the Company s business, financial results and stock price.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

In July 2010, the Company s Board of Directors approved a stock repurchase program under which the Company may repurchase up to $500 million of AES common stock. The Board authorization permits the Company to repurchase stock through a variety of methods, including open market repurchases and/or privately negotiated transactions. The original authorization was set to expire on December 31, 2010; however, in December 2010, the Board authorized an extension of the stock repurchase program. There can be no assurance as to the amount, timing or prices of repurchases, which may vary based on market conditions and other factors. The stock repurchase program may be modified, extended or terminated by the Board of Directors at any time. During the three months ended March 31, 2011, shares of common stock repurchased under this plan totaled 4,943,011 at a total cost of $63 million plus a nominal amount of commissions (average of $12.68 per share including commissions), bringing the cumulative total purchases under the program to 13,325,836 shares at a total cost of $162 million plus a nominal amount of commissions (average of $12.16 per share including commissions). There was $338 million remaining under the stock repurchase program available for future repurchases at March 31, 2011.

The following table presents information regarding purchases made by The AES Corporation of its common stock in the first quarter of 2011:

Repurchase Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Repurchased as Part of a Publicly Announced Repurchase Plan	Dollar Value of Maximum Number of Shares To Be Purchased Under the Plan
1/1/11 - 1/31/11	322,000	$ 12.23	322,000	$ 396,793,782
2/1/11 - 2/28/11	866,210	$ 12.41	866,210	$ 386,043,195
3/1/11 - 3/31/11	3,754,801	$ 12.75	3,754,801	$ 338,178,569
Total	4,943,011	$ 12.66	4,943,011	

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. REMOVED AND RESERVED

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

2.1	Agreement and Plan of Merger, dated April 19, 2011, by and among The AES Corporation, DPL Inc. and Dolphin Sub, Inc. is incorporated herein by reference to Exhibit 2.1 of the Company s Form 8-K filed on April 20, 2011
10.1	Exhibits B-1 B-7 to the Fifth Amended and Restated Credit and Reimbursement Agreement, dated as of July 29, 2010 are incorporated here in by reference to Exhibits 10.1.N 10.1.T of the Company s Form 10-Q for the period ending June 30, 2009.
31.1	Rule13a-14(a)/15d-14(a) Certification of Paul Hanrahan (filed herewith).
31.2	Rule 13a-14(a)/15d-14(a) Certification of Victoria D. Harker (filed herewith).
32.1	Section 1350 Certification of Paul Hanrahan (filed herewith).
32.2	Section 1350 Certification of Victoria D. Harker (filed herewith).
101.INS	XBRL Instance Document (furnished herewith as provided in Rule 406T of Regulation S-T).
101.SCH	XBRL Taxonomy Extension Schema Document (furnished herewith as provided in Rule 406T of Regulation S-T).
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document (furnished herewith as provided in Rule 406T of Regulation S-T).
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document (furnished herewith as provided in Rule 406T of Regulation S-T).
101.LAB	XBRL Taxonomy Extension Label Linkbase Document (furnished herewith as provided in Rule 406T of Regulation S-T).
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document (furnished herewith as provided in Rule 406T of Regulation S-T).

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

THE AES CORPORATION

(Registrant)

Date: May 6, 2011

By: /s/ VICTORIA D. HARKER
Name: Victoria D. Harker
Title: *Executive Vice President and Chief Financial Officer*

(Principal Financial Officer)

By: /s/ MARY E. WOOD
Name: Mary E. Wood
Title: *Vice President and Controller*
(Principal Accounting Officer)