Our workforce of 27,000 people is committed to improving lives by providing safe, reliable and sustainable energy solutions in every market we serve.

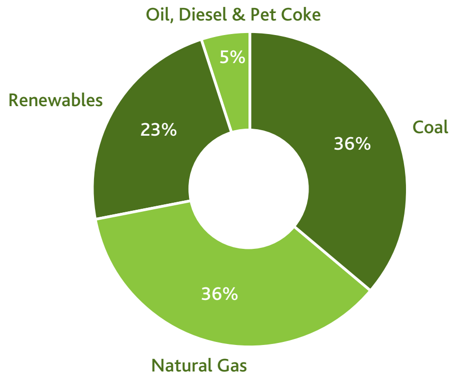
Annual Report 2011

AES 30th

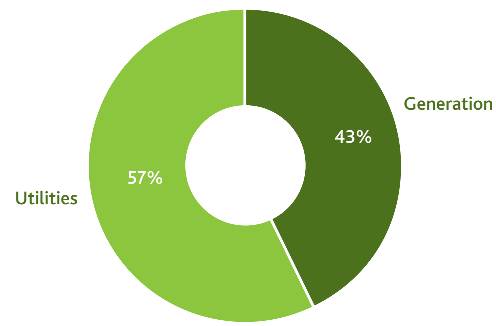
For three decades, AES has helped drive energy sector growth and pioneered advances in many markets, generating global industry leadership from innovation and operational excellence. With deep local knowledge and superior operational skills, we are committed to meeting the world's changing energy needs.

30 years

Megawatts by Fuel Type



Gross Margin by Generation/Utilities



From where we started in 1981...

160 MW
180 AES people
1 generation customer

...to where we are today...

44,200 MW
27,000 AES people
100 million generation customers
12 million utility customers

...to where we are going...

Chairman and CEO Letter to AES Shareholders

Our 30th anniversary was a year of success and transformation for AES. Indeed, we have a new strategy, a new focus on our shareholders and a new leadership team. As a result, we achieved important performance milestones and significantly sharpened our focus on our core markets and returns to our shareholders.

In 2011, we launched several important initiatives to create shareholder value, including:

- Refining our strategy to focus our efforts on those markets where we have a competitive advantage
- Rationalizing and reducing corporate overhead and business development costs
- Restructuring our organization to support our new strategy and improve operations

Subsidiary Distributions
Dollars in millions

Moreover, we announced our plan to declare a common stock dividend in the third quarter of 2012 to further support our commitment to grow total shareholder return.

AES' financial and operational success in 2011 was highlighted by $1.3 billion in dividends from our subsidiaries[1], the highest amount recorded in AES history. We also added 2,000 megawatts (MW) of new capacity from construction projects and completed the acquisition of Dayton Power and Light (DP&L), one of our largest acquisitions ever.

A key element of our transformation was a streamlined organizational structure which we implemented at the beginning of 2012. We aligned our operations along two primary lines of business, Global Generation and Global Utilities, with each unit managed by dedicated Chief Operating Officers: Ned Hall and Andy Vesey, respectively. In addition to her role as Chief Financial Officer, Victoria Harker assumed additional responsibilities by leading Risk and Global Business Services, which includes information technology and non-fuel sourcing. This new structure will enable AES to more effectively leverage its scale and operational synergies across similar businesses while reducing overhead costs.

Celebrating our 30th anniversary in 2011 gave us the opportunity to reflect on our history with a renewed sense of purpose, and to implement the changes we believe will set AES on the path to strong and sustainable earnings growth.

[1] See Financial Notes on page 7 for definition and reconciliation.

Our Results

AES met or exceeded its most important financial and operating targets for 2011 despite confronting the adverse impacts of declining gas and power prices combined with other global economic challenges. Our financial results include:

- Adjusted Earnings Per Share[2] of $1.04, exceeding our guidance range and representing a 6% increase over 2010
- Proportional Free Cash Flow[2] of $932 million, coming in at the high end of our guidance range
- Subsidiary distributions[2] of more than $1.3 billion, exceeding our guidance range and reaching an all-time high for AES

Going forward, we are prepared to deal with continued volatility in commodity and energy prices and uncertainties regarding the future of the euro and slowing global economic growth.

Our 2011 financial results benefited from new and growing businesses, including a full year of operations from Ballylumford, a 1,246 MW combined cycle gas plant in Northern Ireland, and improved operations at many of our businesses. Strong energy demand growth in Latin America and favorable foreign currency exchange rates helped drive our robust operating performance for the year. These positive trends more than offset one time transaction costs related to our acquisition of DP&L and an anticipated lower tariff at AES Eletropaulo in Brazil.

Our Shareholders

Our key objective is to deliver compelling total shareholder returns. Even though it was a year of financial achievement, we were disappointed our stock price declined 2.8% versus the 2.1% increase for the S&P 500 in 2011. Nonetheless, after we launched our new initiatives in the fourth quarter of 2011, our stock outperformed both the S&P 500 and the S&P Utilities Index.

We recognize that balanced and disciplined capital allocation is one of the primary responsibilities of our Board and leadership team. A new Investment Committee process was established last year to evaluate growth projects and acquisitions on a global basis by comparing potential returns with other uses of capital, such as paying down debt or stock repurchases. In 2011, we repurchased approximately 26 million shares at an average price of $10.93 per share, which contributed to a total stock buyback of $378 million over the eighteen months ending December 2011.

Our landmark decision to initiate a dividend in the third quarter of 2012 was announced in 2011. A dividend is a significant component of total shareholder return, and we believe this action demonstrates our commitment to return cash to shareholders on an ongoing basis.

[2] See Financial Notes on page 7 for definition and reconciliation.

Our Markets

Every day, our work improves the lives of more than 100 million people by safely delivering reliable and sustainable energy solutions in the markets we serve. We leverage our unique electricity platforms and the knowledge of our people to meet our customers' needs.

On November 28th, we welcomed DP&L to the AES family of companies, an important addition to our U.S. and utility platforms. DP&L builds on our existing presence in the Midwest anchored in Indiana at Indianapolis Power and Light and within the large PJM energy market. We believe there will be many benefits for our people, the customers we serve and the communities in which we work from increasing our presence in this attractive market.

In 2011, we also made progress in aligning our portfolio, most notably:

- Sold AES Bohemia in the Czech Republic and two distribution businesses in Argentina
- Reached agreement to transfer 80% of our equity interest in Cartagena, a 1,200 MW combined cycle gas plant in Spain, to GDF Suez
- Sold our telecommunications business in Brazil for nearly $1 billion at a time of peak interest in broadband services in a rapidly growing market

As we go forward, we will continue to implement our strategy to focus on markets where we have a competitive advantage and exit those markets where we do not.

Our Construction Programs

We brought 2,000 MW of new capacity online from diverse fuel sources in key markets. The largest plants we commissioned in 2011 were:

- Maritza, a 670 MW lignite-fired plant and state of the art ash disposal facility in Bulgaria
- Changuinola, a 223 MW hydroelectric plant and reservoir in Panama
- Angamos, a 545 MW coal-fired plant in Chile

These plants have long-term power purchase agreements with strong clients and are in markets where we have an important presence. We are well-positioned for stronger earnings growth in 2012 with a full year's operation of this new capacity.

We also commissioned a number of renewable energy projects in Western Europe and the U.S. such as Laurel Mountain, a 98 MW wind facility and 32 MW energy storage system serving the PJM market. In recognition of our achievements there, Laurel Mountain was selected by *Renewable Energy World* as Wind Project of the Year for 2011.

In 2011, we continued to pursue new initiatives that will ensure earnings growth in the long-term. We completed a $1.5 billion non-recourse financing for our 1,200 MW Mong Duong II coal-fired power plant in Vietnam. With our project partners, the China Investment Corporation and Posco Power of Korea, we won *Asia Finance Magazine's* Deal of the Year. We also announced a new partnership agreement with Koç Holding, the largest industrial group in Turkey, with the initial step to develop Ayas, a 625 MW greenfield coal-fired plant in Southeast Turkey.

Our People

AES has always been a values-driven company. Our core values: safety, integrity, honoring commitments, pursuing excellence and having fun through work. They are the foundation of everything we do.

Safety continued to be our highest priority. During 2011 we completed the second year of a three-year action plan to elevate our safety culture to world-class levels at every single AES location. We've seen the positive results of our safety focus through the trends in both proactive and reactive safety performance indicators and numerous national safety recognitions in 2011. Nevertheless, we are not satisfied with these achievements and have identified areas where we still have work to do in the coming year.

Our people's commitment to operational excellence was demonstrated by:

- Significant improvement in our key performance indicators which exceeded targets and prior years' performance
- Increased savings from our global sourcing efforts in solid fuels and other areas which exceeded targets for the year by roughly 100%
- APEX (AES Performance Excellence), our common approach to solving and tracking fundamental business issues while fostering innovation, created more than $100 million in benefits and trained more than 13,000 people to ensure continued progress in the future

We expect our efforts throughout 2011 will support strong full year earnings for 2012.

The operational improvements we achieved are recognized by our peers in the electric industry. This past year, the operational and environmental turnaround achieved at Masinloc, our 660 MW coal-fired plant in the Philippines, was recognized with one of our industry's most prestigious awards, the Edison Electric Institute's International Edison Award. AES is the only company to have received this honor twice within a five year period. Since purchasing the plant in 2008, we have:

- Increased energy output by 31% compared to its historical average
- Lowered customers' bills and improved the plant's environmental and safety performance dramatically
- Invested in education and social welfare to enhance the quality of life in the surrounding community

Our success in the Philippines is one example of many where we are promoting a culture of excellence.

Our Future

Our achievements in 2011 provide AES with a strong platform for further success in 2012. Earnings and cash flow will benefit from a full-year of operations at our new generation facilities and the cost savings initiatives implemented in the fourth quarter of 2011.

We will continue to sell underperforming and nonstrategic assets and redeploy that capital where it creates the most value for our shareholders. Our shareholders will also benefit as we consolidate and extend the gains from our new organizational structure in the year ahead.

Looking to the longer term, we will continue to execute our strategy of focusing on markets where we have or believe we can create a sustainable competitive advantage. We will draw on our shared values as we honor our commitments to our shareholders, customers, the communities we serve and our people.

We believe our efforts in all these areas will deliver compelling total shareholder returns to our investors in 2012 and beyond.

Phil Odeen
Chairman of the Board
March 1, 2012

Andrés Gluski
President and Chief Executive Officer
March 1, 2012

Financial Notes: Non-GAAP Financial Measures Reconciliation (Unaudited)

($ in millions, except per share amounts)	Year Ended December 31, 2011	2010
Reconciliation of Adjusted Earnings Per Share (1)		
Diluted EPS From Continuing Operations	**$ 0.59**	**$ 0.63**
Derivative Mark-to-Market (Gains)/Losses (2)	0.01	—
Currency Transaction (Gains)/Losses (3)	0.04	(0.05)
Disposition/Acquisition (Gains)/Losses	—	—(4)
Impairment Losses	0.36(5)	0.37(6)
Debt Retirement (Gains)/Losses	0.04(7)	0.03(8)
Adjusted Earnings Per Share (1)	**$ 1.04**	**$ 0.98**
Calculation of Maintenance Capital Expenditures for Free Cash Flow (9) Reconciliation Below:		
Maintenance Capital Expenditures	$ 889	$ 727
Environmental Capital Expenditures	82	71
Growth Capital Expenditures	1,490	1,535
Total Capital Expenditures	**$ 2,461**	**$ 2,333**
Reconciliation of Proportional Operating Cash Flow (10)		
Consolidated Operating Cash Flow	$ 2,884	$ 3,465
Less: Proportional Adjustment Factor	1,312	1,617
Proportional Operating Cash Flow (10)	**$ 1,572**	**$ 1,848**
Reconciliation of Free Cash Flow (9)		
Consolidated Operating Cash Flow	$ 2,884	$ 3,465
Less: Maintenance Capital Expenditures, net of reinsurance proceeds	878	727
Less: Environmental Capital Expenditures	82	71
Free Cash Flow (9)	**$ 1,924**	**$ 2,667**
Reconciliation of Proportional Free Cash Flow (9),(10)		
Proportional Operating Cash Flow	$ 1,572	$ 1,848
Less: Proportional Maintenance Capital Expenditures, net of reinsurance proceeds and Environmental Capital Expenditures	640	557
Proportional Free Cash Flow (9),(10)	**$ 932**	**$ 1,291**
Reconciliation of Proportional Gross Margin (10)		
Consolidated Gross Margin	$ 4,134	$ 3,936
Less: Proportional Adjustment Factor	1,627	1,537
Proportional Gross Margin (10)	**$ 2,507**	**$ 2,399**

(1) 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.

(2) Derivative mark-to-market (gains)/losses were net of income tax per share of $0.01 and $0.00 for the twelve months ended December 31, 2011 and 2010, respectively.

(3) Unrealized foreign currency transaction (gains)/losses were net of income tax per share of $0.00 and ($0.01) for the twelve months ended December 31, 2011 and 2010, respectively.

(4) The Company has not adjusted for the gain or the related tax effect from the sale of its indirect investment in CEMIG in its determination of adjusted EPS because the gain was recognized by an equity method investee. The Company does not adjust for transactions of its equity method investees in its determination of adjusted EPS.

(5) Amount includes asset impairments, equity method investment impairments and a goodwill impairment. Asset impairments primarily includes impairments of wind turbines and deposits of $116 million ($75 million, or $0.10 per share, net of income taxes), Tisza II of $52 million ($50 million, or $0.06 per share, net of income taxes), Kelanitissa of $42 million ($38 million, or $0.05 per share, net of non-controlling interest), Bohemia of $9 million, or $0.01 per share. Equity method investment impairments primarily included the impairments at Chigen, including Yangcheng, of $79 million, or $0.10 per share. Goodwill impairment at Chigen of $17 million, or $0.02 per share.

(6) Amount primarily includes asset impairments at Southland (Huntington Beach) of $200 million, Tisza of $85 million, and Deepwater of $79 million ($130 million, or $0.17 per share, $69 million, or $0.09 per share, and $51 million, or $0.07 per share, net of income tax, respectively) and goodwill impairment at Deepwater of $18 million (or $0.02 per share, with no income tax impact).

(7) Amount includes loss on retirement of debt at Gener of $38 million ($22 million, or $0.03 per share, net of income taxes and noncontrolling interests) and at IPL of $15 million ($10 million, or $0.01 per share, net of income taxes).

(8) Amount includes loss on retirement of debt at the Parent Company of $15 million, at Andres of $10 million, and at Itabo of $8 million ($10 million, or $0.01 per share, net of income tax at the Parent Company, $10 million, or $0.01 per share at Andres net of income tax, and $4 million, or $0.01 per share, net of noncontrolling interest at Itabo).

(9) Free cash flow (a non-GAAP financial measure) is defined as net cash from operating activities less maintenance capital expenditures (including environmental capital expenditures), net of reinsurance proceeds from third parties. AES believes that free cash flow is a useful measure for evaluating our financial condition because it represents the amount of cash provided by operations less maintenance capital expenditures as defined by our businesses, that may be available for investing or for repaying debt.

(10) AES is a holding company that derives its income and cash flows from the activities of its subsidiaries, some of which may not be wholly-owned by the Company. Accordingly, the Company has presented certain financial metrics which are defined as Proportional (a non-GAAP financial measure). Proportional metrics present the Company's estimate of its share in the economics of the underlying metric. The Company believes that the Proportional metrics are useful to investors because they exclude the economic share in the metric presented that is held by non-AES shareholders. For example, Operating Cash Flow is a GAAP metric which presents the Company's cash flow from operations on a consolidated basis, including operating cash flow allocable to noncontrolling interests. Proportional Operating Cash Flow removes the share of operating cash flow allocable to noncontrolling interests and therefore may act as an aid in the valuation of the Company. Proportional metrics are reconciled to the nearest GAAP measure. Certain assumptions have been made to estimate our proportional financial measures. These assumptions include: (i) the Company's economic interest has been calculated based on a blended rate for each consolidated business when such business represents multiple legal entities; (ii) the Company's economic interest may differ from the percentage implied by the recorded net income or loss attributable to noncontrolling interests or dividends paid during a given period; (iii) the Company's economic interest for entities accounted for using the hypothetical liquidation at book value method is 100%; (iv) individual operating performance of the Company's equity method investments is not reflected and (v) all intercompany amounts have been excluded as applicable.

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

FORM 10-K

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

For the Fiscal Year Ended December 31, 2011

-OR-

☐ **TRANSITION REPORT FILED 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)**

Registrant's telephone number, including area code: (703) 522-1315

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	**New York Stock Exchange**
AES Trust III, $3.375 Trust Convertible Preferred Securities	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15 (d) of the Act. Yes ☐ No ☒

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 ☒ 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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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 ☒	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 ☒

The aggregate market value of the voting and non-voting common equity held by non-affiliates on June 30, 2011, the last business day of the Registrant's most recently completed second fiscal quarter (based on the closing sale price of $12.74 of the Registrant's Common Stock, as reported by the New York Stock Exchange on such date) was approximately $8.37 billion.

The number of shares outstanding of the Registrant's Common Stock, par value $0.01 per share, on February 17, 2012, was 765,906,019.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Registrant's Proxy Statement for its 2012 annual meeting of stockholders are incorporated by reference in Parts II and III

THE AES CORPORATION

FISCAL YEAR 2011 FORM 10-K
TABLE OF CONTENTS

PART I

In this Annual Report the terms "AES," "the Company," "us," or "we" refer to The AES Corporation and all of its subsidiaries and affiliates, collectively. The term "The AES Corporation" and "Parent Company" refers only to the parent, publicly-held holding company, The AES Corporation, excluding its subsidiaries and affiliates.

FORWARD-LOOKING INFORMATION

In this filing we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, and future events or performance. Such statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Although we believe that these forward-looking statements and the underlying assumptions are reasonable, we cannot assure you that they will prove to be correct.

Forward-looking statements involve a number of risks and uncertainties, and there are factors that could cause actual results to differ materially from those expressed or implied in our forward-looking statements. Some of those factors (in addition to others described elsewhere in this report and in subsequent securities filings) include:

- the economic climate, particularly the state of the economy in the areas in which we operate, including the fact that the global economy faces considerable uncertainty for the foreseeable future, which further increases many of the risks discussed in this Form 10-K;
- changes in inflation, demand for power, interest rates and foreign currency exchange rates, including our ability to hedge our interest rate and foreign currency risk;
- changes in the price of electricity at which our Generation businesses sell into the wholesale market and our Utility businesses purchase to distribute to their customers, and the success of our risk management practices, such as our ability to hedge our exposure to such market price risk;
- changes in the prices and availability of coal, gas and other fuels (including our ability to have fuel transported to our facilities) and the success of our risk management practices, such as our ability to hedge our exposure to such market price risk, and our ability to meet credit support requirements for fuel and power supply contracts;
- changes in and access to the financial markets, particularly changes affecting the availability and cost of capital in order to refinance existing debt and finance capital expenditures, acquisitions, investments and other corporate purposes;
- our ability to manage liquidity and comply with covenants under our recourse and non-recourse debt, including our ability to manage our significant liquidity needs and to comply with covenants under our senior secured credit facility and other existing financing obligations;
- changes in our or any of our subsidiaries' corporate credit ratings or the ratings of our or any of our subsidiaries' debt securities or preferred stock, and changes in the rating agencies' ratings criteria;
- our ability to purchase and sell assets at attractive prices and on other attractive terms;
- our ability to compete in markets where we do business;
- our ability to manage our operational and maintenance costs;
- the performance and reliability of our generating plants, including our ability to reduce unscheduled down-times;
- our ability to locate and acquire attractive "greenfield" projects and our ability to finance, construct and begin operating our "greenfield" projects on schedule and within budget;

- our ability to enter into long-term contracts, which limit volatility in our results of operations and cash flow, such as Power Purchase Agreements ("PPA"), fuel supply, and other agreements and to manage counterparty credit risks in these agreements;
- variations in weather, especially mild winters and cooler summers in the areas in which we operate, low levels of wind or sunlight for our wind and solar businesses, and the occurrence of difficult hydrological conditions for our hydro-power plants, as well as hurricanes and other storms and disasters;
- our ability to meet our expectations in the development, construction, operation and performance of our wind businesses, which rely, in part, on actual wind conditions and wind turbine performance being in line with our expectations;
- the success of our initiatives in other renewable energy projects, as well as greenhouse gas emissions reduction projects and energy storage projects;
- our ability to keep up with advances in technology;
- the potential effects of threatened or actual acts of terrorism and war;
- the expropriation or nationalization of our businesses or assets by foreign governments, whether with or without adequate compensation;
- our ability to achieve expected rate increases in our Utility businesses;
- changes in laws, rules and regulations affecting our international businesses;
- changes in laws, rules and regulations affecting our North America business, including, but not limited to, deregulation of wholesale power markets and its effects on competition, the ability to recover net utility assets and other potential stranded costs by our utilities, the establishment of a regional transmission organization that includes our utility service territory, the application of market power criteria by the Federal Energy Regulatory Commission, changes in law resulting from new federal energy legislation, including the effects of the repeal of Public Utility Holding Company Act of 1935, and changes in political or regulatory oversight or incentives affecting our wind business, our solar joint venture, our other renewables projects and our initiatives in greenhouse gas reductions and energy storage including tax incentives;
- changes in environmental laws, including requirements for reduced emissions of sulfur, nitrogen, carbon, mercury, hazardous air pollutants and other substances, greenhouse gas legislation, regulation and/or treaties and coal ash regulation;
- changes in tax laws and the effects of our strategies to reduce tax payments;
- the effects of litigation and government and regulatory investigations;
- our ability to maintain adequate insurance;
- decreases in the value of pension plan assets, increases in pension plan expenses and our ability to fund defined benefit pension and other post-retirement plans at our subsidiaries;
- losses on the sale or write-down of assets due to impairment events or changes in management intent with regard to either holding or selling certain assets;
- changes in accounting standards, corporate governance and securities law requirements;
- our ability to maintain effective internal controls over financial reporting;
- our ability to attract and retain talented directors, management and other personnel, including, but not limited to, financial personnel in our foreign businesses that have extensive knowledge of accounting principles generally accepted in the United States;

- the performance of business and asset acquisitions, including our recent acquisition of DPL Inc., and our ability to successfully integrate and operate acquired businesses and assets, such as DPL, and effectively realize anticipated benefits; and
- information security breaches could harm our businesses.

These factors in addition to others described elsewhere in this Form 10-K, including those described under Item 1A.—Risk Factors, and in subsequent securities filings, should not be construed as a comprehensive listing of factors that could cause results to vary from our forward looking information.

We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise. If one or more forward-looking statements are updated, no inference should be drawn that additional updates will be made with respect to those or other forward-looking statements.

ITEM 1. BUSINESS

Overview

We are a global power company, dedicated to improving lives by providing safe, reliable and sustainable energy solutions in every market we serve. We own a portfolio of electricity generation and distribution businesses on five continents in 27 countries, with total capacity of approximately 44,200 Megawatts (“MW”) and distribution networks serving approximately 12 million customers as of December 31, 2011. In addition, we have approximately 2,400 MW under construction in eight countries. We were incorporated in Delaware in 1981.

We own and operate two primary types of businesses. 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 and other intermediaries. The second is our Utilities business, where we own and/or operate utilities to generate, distribute, transmit and sell electricity to end-user customers in the residential, commercial, industrial and governmental sectors within a defined service area.

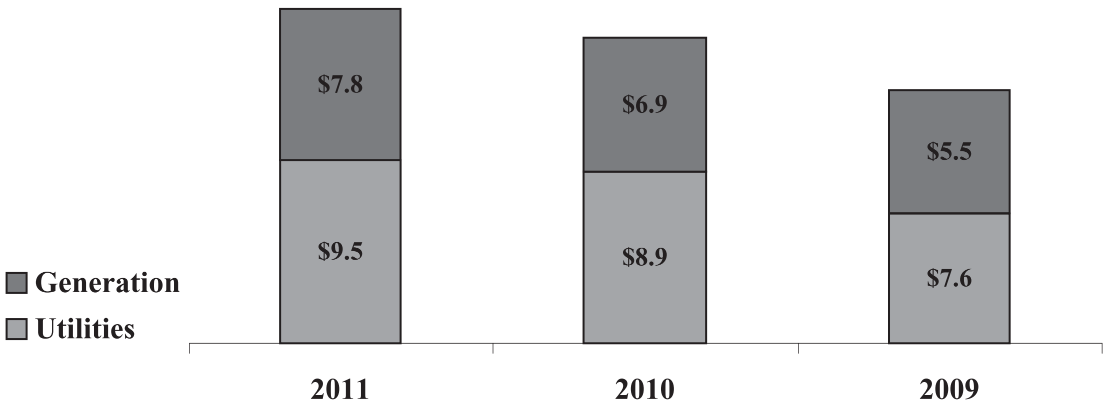
Our assets are diverse with respect to fuel source and type of market, which helps reduce certain types of operating risk. Our portfolio employs a broad range of fuels, including coal, diesel, fuel oil, natural gas, biomass and renewable sources such as hydroelectric power, wind and solar, which reduces the risks associated with dependence on any one fuel source. Our portfolio combines a presence in stable markets in developed countries with faster growing emerging markets. In addition, our Generation portfolio is largely contracted, which reduces the risk related to market prices of electricity and fuel. We also attempt to limit risk by matching the currency of most of our subsidiary debt to the revenue of the underlying business and by hedging some of our interest rate and commodity risk. However, our business is still subject to these and other risks, which are further described in Item 1A.—Risk Factors of this Form 10-K.

Our goal is to maximize value for our shareholders by growing cash flow and earnings per share and achieving better returns on our investments. We will expand our platforms in our core markets, specifically Brazil, Chile, Colombia and the United States, and will work to develop growth platforms in key markets including Turkey, Poland and the United Kingdom. Over time, by focusing our growth and exiting select non-strategic markets, we expect to narrow our geographic focus to achieve better results with fewer countries. Across our portfolio, we will work to optimize profitability, as well as reduce our overhead and business development costs. Finally, we have announced our intent to initiate a dividend beginning in the third quarter of 2012, with the first payment expected to be made in the fourth quarter of 2012.

Key Lines of Business

AES’ primary sources of revenue and gross margin today are from Generation and Utilities. These businesses are distinguished by the nature of the customers, operational differences, cost structure, regulatory environment and risk exposure. The breakout of revenue and gross margin between Generation and Utilities for the years ended December 31, 2011, 2010 and 2009, respectively, is shown below. Operating results for integrated utilities, which have both Generation and Utilities, are reflected in the Utilities amounts below.

Revenue
($ in billions)



Gross Margin
($ in billions)

(1) Utilities gross margin includes the margin from generation businesses owned by the Company and from whom the utility purchases energy.

Generation

We currently own or operate a generation portfolio of approximately 33,800 MW, excluding the generation capabilities of our integrated utilities, consisting of 98 Generation facilities in 22 countries on five continents at our generation businesses. We also have approximately 2,100 MW of capacity currently under construction in four countries. We are a major power source in many countries, such as Chile, where AES Gener ("Gener") is the second largest electricity generation company in terms of capacity. Our Generation business uses a wide range of technologies and fuel types including coal, combined-cycle gas turbines, hydroelectric power and biomass. Generation revenue was $7.8 billion, $6.9 billion and $5.5 billion for the years ended December 31, 2011, 2010 and 2009, respectively.

Performance drivers for our Generation businesses include, among other factors, plant reliability, fuel costs, power prices, volume and fixed-cost management. Growth in the Generation business is largely tied to securing new power purchase agreements ("PPAs"), expanding capacity in our existing facilities, reducing our fixed costs and building or acquiring new power plants.

The majority of the electricity produced by our Generation businesses is sold under long-term PPAs, to wholesale customers. In 2011, approximately 71% of the contracted revenue from our Generation business was from plants that operate under PPAs of three years or longer for 75% or more of their output capacity. These businesses often reduce their exposure to fuel supply risks by entering 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. These long-term contractual agreements help reduce the volatility of our cash flows and earnings and also reduce exposure to volatility in the market price for electricity and fuel; however, the amount of earnings and cash flow predictability varies from business to business based on the degree to which its exposure is limited by the contracts it has negotiated.

Our Generation businesses with long-term contracts face most of their competition from other utilities and independent power producers ("IPPs") prior to the execution of a power sales agreement during the development phase of a project or upon expiration of an existing agreement. Once a project is operational, we traditionally have faced limited competition due to the long-term nature of the generation contracts. However, as our existing contracts expire, we may face increased competition to attract new customers and maintain our current customer base.

The balance of our Generation business sells power through competitive markets under short-term contracts, directly in the spot market or, in some cases, at regulated prices. As a result, the cash flows and earnings associated with these businesses are more sensitive to fluctuations in the market price for electricity, natural gas, coal and other fuels. Competitive factors for these facilities include price, reliability, operational cost and third-party credit requirements.

Utilities

AES utility businesses distribute power to over 12 million people in six countries on five continents and consist primarily of 13 companies owned or operated under management agreements, each of which operates in defined service areas. These businesses also include 29 generation plants in two countries with generation capacity totaling approximately 8,500 MW. These businesses have a variety of structures ranging from pure distribution businesses to fully integrated utilities, which generate, transmit and distribute power. For instance, our wholly-owned subsidiary in the U.S., Indianapolis Power & Light ("IPL"), has the exclusive right to provide retail services to approximately 470,000 customers in Indianapolis, Indiana. The Dayton Power and Light Company ("DP&L") serves approximately 500,000 customers in West Central Ohio. Eletropaulo Metropolitana Electricidade de São Paulo S.A. ("AES Eletropaulo" or "Eletropaulo"), serving the São Paulo metropolitan region for over 100 years, has approximately six million customers and is the largest electricity distribution company in Latin America in terms of revenue and electricity distributed. Utilities revenue was $9.5 billion, $8.9 billion and $7.6 billion for the years ended December 31, 2011, 2010 and 2009, respectively.

Performance drivers for Utilities include, but are not limited to, reliability of service, management of working capital, negotiation of tariff adjustments, compliance with extensive regulatory requirements, and in developing countries, reduction of commercial and technical losses. The results of operations of our Utilities businesses are sensitive to changes in economic growth, regulations and variations in weather conditions in the areas in which they operate. In certain locations, our distribution businesses face increased competition as a result of changes in laws and regulations which allow wholesale and retail services to be provided on a competitive basis.

The majority of our utilities face relatively little direct competition due to significant barriers to entry, which are present in these markets. Competition is a factor in efforts to acquire existing businesses. In this arena, we compete against a number of other market participants, some of which have greater financial resources, have been engaged in distribution related businesses for longer periods of time and/or have accumulated more significant portfolios. Relevant competitive factors for our power distribution businesses include financial resources, governmental assistance, regulatory restrictions and access to non-recourse financing.

Renewables and Other Initiatives

In recent years, as demand for renewable sources of energy has grown, we have developed projects in wind, solar and other renewable initiatives including energy storage. In 2005, we started a wind generation business

(“Wind Generation”), which currently has 21 plants in operation in five countries totaling approximately 1,800 MW in generation capacity and is one of the largest producers of wind power in the U.S. In addition, 205 MW are under construction in four countries. In March 2008, we formed AES Solar Energy LLC (“AES Solar”), a joint venture with Riverstone Holdings, LLC (“Riverstone”), a private equity firm, which has since commenced commercial operations of 26 plants totaling 151 MW of solar projects in Bulgaria, France, Greece, Italy and Spain. We also have a line of business to develop and implement utility scale energy storage systems (such as batteries), which store and release power when needed. None of these initiatives are currently material to our operations, however, there are risks associated with these initiatives, which are further described in Item 1A.—Risk Factors of this Form 10-K.

Risks

We routinely encounter and address risks, some of which may cause our future results to be different, sometimes materially different, than we presently anticipate. The categories of risk we have identified in Item 1A.—Risk Factors of this Form 10-K include the following:

- risks related to our high level of indebtedness;
- risks associated with our ability to raise needed capital;
- external risks associated with revenue and earnings volatility;
- risks associated with our operations;
- risks associated with governmental regulation and laws; and
- risks associated with our disclosure controls and internal controls over financial reporting.

The categories of risk identified above are discussed in greater detail in Item 1A.—Risk Factors of this Form 10-K. These risk factors should be read in conjunction with Item 7.—Management’s Discussion and Analysis of Financial Condition and Results of Operations, and the Consolidated Financial Statements and related notes included elsewhere in this report.

Our Organization and Segments

We believe our broad geographic footprint allows us to focus development in targeted markets with opportunities for new investment, and provides stability through our presence in more developed regions. In addition, our presence in each region affords us important relationships and helps us identify local markets with attractive opportunities for new investment. In October 2011, the Company announced a plan to redefine its operational management and organizational structure. The planned reporting structure will remain organized along two lines of business—Generation and Utilities, each led by a Chief Operating Officer (“COO”), who in turn reports to our Chief Executive Officer (“CEO”). Our CEO and COOs are based in Arlington, Virginia.

We are continuing to evaluate both the timing and impact, if any, that the new operational and management and organizational structure will have on our reportable segments. For the year ended 2011, the Company’s segment 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”), which reflects how we manage the business internally. Additionally, Wind Generation is managed within our North America region. For financial reporting purposes, the Company has six reportable segments which include:

- 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 and Wind Generation businesses as well as the Company's renewables initiatives are reported within "Corporate and Other" because they do not require separate disclosure under segment reporting accounting guidance. See Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations for further discussion of the Company's segment structure used for financial reporting purposes.

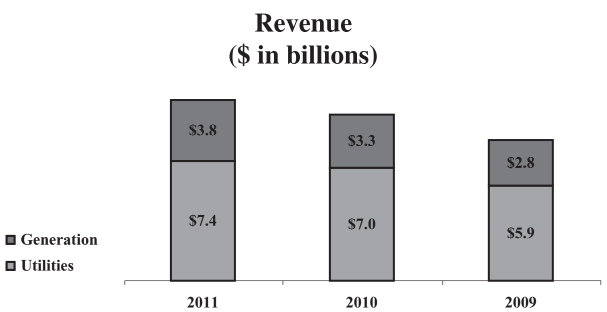
The following describes our businesses as they are aligned in our segment reporting structure for financial reporting purposes.

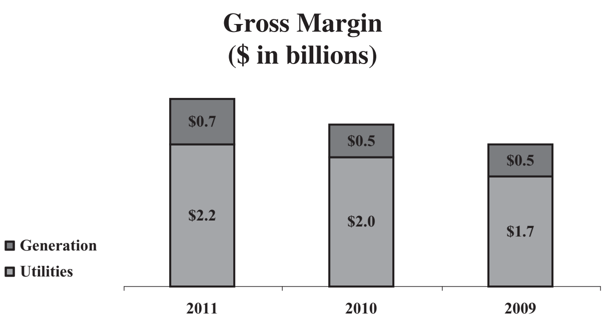
Latin America

Our Latin America operations accounted for 65%, 65% and 66% of consolidated AES revenue in 2011, 2010 and 2009, respectively. The following table provides highlights of our Latin America operations:

Countries	Argentina, Brazil, Chile, Colombia, Dominican Republic, El Salvador and Panama
Generation Capacity	12,616 Gross MW
Utilities Penetration	8.7 million customers (48,470 Gigawatt Hours ("GWh"))
Generation Facilities	56 (including 1 under construction)
Utilities Businesses	6
Key Generation Businesses	Gener, Tietê and Alicura
Key Utilities Businesses	Eletropaulo and Sul

The bar charts below shows the breakdown between our Latin America Generation and Utilities segments as a percentage of total Latin America revenue and gross margin for the years ended December 31, 2011, 2010, and 2009. See Note 16—*Segment and Geographic Information* in the Consolidated Financial Statements in Item 8 of this Form 10-K for information on revenue from external customers, Adjusted Gross Margin (a non-GAAP measure) and total assets by segment.





Latin America Generation. Our largest generation business in Latin America, AES Tietê ("Tietê"), located in Brazil, represents approximately 18% of the total generation capacity in the state of São Paulo and is the tenth largest generator in Brazil. AES holds a 24% economic interest in Tietê. In Chile, we are the second largest generator of power. We currently have one new generation plant under construction in Chile with a generation capacity of 270 MW.

Set forth below is a list of our Latin America Generation facilities:

Generation

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
Alicura	Argentina	Hydro	1,050	99%	2000
Gener—TermoAndes	Argentina	Gas/Diesel	643	71%	2000
Los Caracoles[1]	Argentina	Hydro	125	0%	2009
Paraná-GT	Argentina	Gas/Diesel	845	99%	2001
Quebrada de Ullum[1]	Argentina	Hydro	45	0%	2004
Rio Juramento—Cabra Corral	Argentina	Hydro	102	99%	1995
Rio Juramento—El Tunal	Argentina	Hydro	10	99%	1995
San Juan—Sarmiento	Argentina	Gas/Diesel	33	99%	1996
San Juan—Ullum	Argentina	Hydro	45	99%	1996
San Nicolás	Argentina	Coal/Gas/Oil	675	99%	1993
Tietê[2]	Brazil	Hydro	2,659	24%	1999
Uruguaiana	Brazil	Gas	639	46%	2000
Gener—Electrica Angamos	Chile	Coal	545	71%	2011
Gener—Electrica Santiago[3]	Chile	Gas/Diesel	479	64%	2000
Gener—Electrica Ventanas[4]	Chile	Coal	272	71%	2010
Gener—Gener[5]	Chile	Hydro/Coal/Diesel /Biomass	1,003	71%	2000
Gener—Guacolda[6],[7]	Chile	Coal/Pet Coke	608	35%	2000
Gener—Norgener	Chile	Coal/Pet Coke	277	71%	2000
Chivor	Colombia	Hydro	1,000	71%	2000
Andres	Dominican Republic	Gas	319	100%	2003
Itabo[8]	Dominican Republic	Coal	295	50%	2000
Los Mina	Dominican Republic	Gas	236	100%	1996
AES Nejapa	El Salvador	Landfill Gas	6	100%	2011
Bayano	Panama	Hydro	260	49%	1999
Changuinola	Panama	Hydro	223	100%	2011
Chiriqui—Esti	Panama	Hydro	120	49%	2003
Chiriqui—La Estrella	Panama	Hydro	48	49%	1999
Chiriqui—Los Valles	Panama	Hydro	54	49%	1999
			12,616		

(1) AES operates these facilities through management or operations and maintenance ("O&M") agreements and owns no equity interest in these businesses.

(2) Tietê plants: Água Vermelha, Bariri, Barra Bonita, Caconde, Euclides da Cunha, Ibitinga, Limoeiro, Mog-Guaçu, Nova Avanhandava, Promissão, Sao Joaquim and seven other small hydroelectric plants below Tietê's wholly-owned subsidiary "PCH Minas Ltda".

(3) Gener—Electrica Santiago plants: Nueva Renca and Renca.

(4) Gener—Electrica Ventanas plant: Nueva Ventanas.

(5) Gener—Gener plants: Alfalfal, Constitución, Laguna Verde, Laguna Verde Turbogas, Laja, Los Vientos, Maitenas, Queltehues, San Francisco de Mostazal, Santa Lidia, Ventanas and Volcán.

(6) Gener—Guacolda plants: Guacolda 1, Guacolda 2, Guacolda 3 and Guacolda 4.

(7) Unconsolidated entities for which the results of operations are reflected in Equity in Earnings of Affiliates.

(8) Itabo plants: Itabo complex (two coal-fired steam turbines and one gas-fired steam turbine).

Generation under construction

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Expected Year of Commercial Operations
Campiche	Chile	Coal	270	71%	2013

Latin America Utilities. Each of our Utilities businesses in Latin America sells electricity under regulated tariff agreements and has transmission and distribution capabilities but none of them has generation capability. AES Eletropaulo, a consolidated subsidiary of which AES owns a 16% economic interest and which has served the São Paulo, Brazil area for over 100 years, has approximately six million customers and is the largest electricity distribution company in Latin America in terms of revenue and electricity distributed. Pursuant to its concession agreement, AES Eletropaulo is entitled to distribute electricity in its service area until 2028. AES Eletropaulo's service territory consists of 24 municipalities in the greater São Paulo metropolitan area and adjacent regions that account for approximately 17% of Brazil's GDP and 40% of the population in the State of São Paulo. AES Sul ("Sul"), a wholly-owned subsidiary, serves over one million customers.

Set forth below is a list of our Latin America Utilities facilities:

Distribution

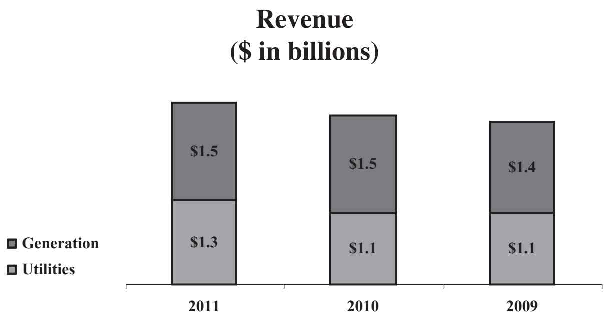
Business	Location	Approximate Number of Customers Served as of 12/31/2011	GWh Sold in 2011	AES Equity Interest (Percent, Rounded)	Year Acquired
Eletropaulo	Brazil	6,348,000	36,817	16%	1998
Sul	Brazil	1,260,000	8,223	100%	1997
CAESS	El Salvador	516,000	2,060	75%	2000
CLESA	El Salvador	304,000	786	64%	1998
DEUSEM	El Salvador	62,000	108	74%	2000
EEO	El Salvador	229,000	476	89%	2000
		8,719,000	48,470		

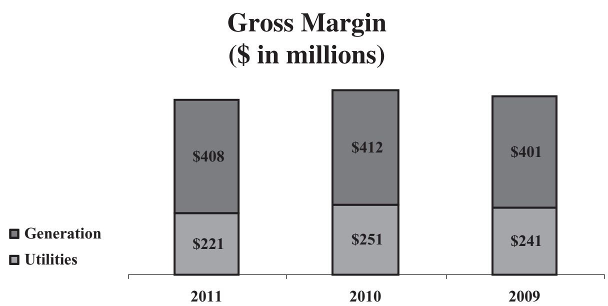
North America

Our North America operations accounted for 16%, 16% and 19% of consolidated revenue in 2011, 2010 and 2009, respectively. The following table provides highlights of our North America operations:

Countries	U.S., Puerto Rico, Mexico and Trinidad
Generation Capacity	15,756 Gross MW
Utilities Penetration	970,000 customers (16,890 GWh)
Generation Facilities	15
Utilities Businesses	2 integrated utilities (includes 18 generation plants)
Key Generation Businesses	Southland and TEG/TEP
Key Utilities Businesses	IPL, DPL

The bar charts below shows the breakdown between our North America Generation and Utilities segments as a percentage of total North America revenue and gross margin for the years ended December 31, 2011, 2010 and 2009. See Note 16—*Segment and Geographic Information* in the Consolidated Financial Statements in Item 8 of this Form 10-K for information on revenue from external customers, Adjusted Gross Margin (a non-GAAP measure) and total assets by segment.





North America Generation. Approximately 92% of the generation capacity is supported by long-term power purchase or tolling agreements. Our North America Generation business consists of seven gas-fired, five coal-fired and three petroleum coke-fired plants in the United States, Puerto Rico, Mexico and Trinidad.

Our largest generation business is AES Southland. This business operates three gas-fired plants, representing generation capacity of 3,853 MW, in the Los Angeles basin under a long-term tolling agreement. Other significant generation facilities include TEG and TEP, which represent a total of 460 MW of long-term contracted generation capacity in Mexico.

Set forth below is a list of our North America Generation facilities:

Generation

Business	Location	Fuel	Gross MW	AES Equity Ownership (Percent, Rounded)	Year Acquired or Began Operation
Mérida III	Mexico	Gas	484	55%	2000
Termoelectrica del Golfo (TEG)	Mexico	Pet Coke	230	99%	2007
Termoelectrica del Peñoles (TEP)	Mexico	Pet Coke	230	99%	2007
Trinidad	Trinidad	Gas	394	10%	2011
Southland—Alamitos	USA—CA	Gas	2,047	100%	1998
Southland—Huntington Beach	USA—CA	Gas	430	100%	1998
Southland—Redondo Beach	USA—CA	Gas	1,376	100%	1998
Hawaii	USA—HI	Coal	203	100%	1992
Warrior Run	USA—MD	Coal	205	100%	2000
Red Oak	USA—NJ	Gas	832	100%	2002
Shady Point	USA—OK	Coal	360	100%	1991
Beaver Valley	USA—PA	Coal	125	100%	1985
Ironwood	USA—PA	Gas	710	100%	2001
Puerto Rico	USA—PR	Coal	454	100%	2002
Deepwater	USA—TX	Pet Coke	160	100%	1986
			8,240		

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Expected Year of Commercial Operations
Trinidad	Trinidad	Gas	394	10%	2012

North America Utilities. AES has two integrated utilities in North America, IPL, which it owns through IPALCO Enterprises, Inc. ("IPALCO"), the parent holding company of IPL and The Dayton Power and Light

Company (“DP&L”), which it owns through DPL Inc. (“DPL”), the parent company of DP&L. IPL generates, transmits, distributes and sells electricity to approximately 470,000 customers in the city of Indianapolis and neighboring areas within the state of Indiana. IPL owns and operates four generating stations. Two of the generating stations are primarily coal-fired stations. The third station has a combination of units that use coal (base load capacity) and natural gas and/or oil (peaking capacity) for fuel to produce electricity. The fourth station is a small peaking station that uses gas-fired combustion turbine technology for the production of electricity. IPL’s gross electric generation capacity is 3,699 MW. Approximately 45% of IPL’s coal is provided by one supplier with which IPL has long-term contracts. A key driver for the business is tariff recovery for environmental projects through the rate adjustment process. IPL’s customers include residential, industrial, commercial and all other which made up 33%, 13%, 36% and 6%, respectively, of North America Utilities revenue for 2011. The remaining 12% of North America Utilities revenue is from DPL.

DP&L generates, transmits, distributes and sells electricity to more than 500,000 customers in a 6,000 square mile area of West Central Ohio. DP&L, with certain other Ohio utilities and their affiliates, commonly owns seven coal-fired electric generating facilities and numerous transmission facilities. DP&L also has one wholly-owned coal-fired plant. DP&L is affiliated with DPL Energy, LLC (“DPLE”) which owns peaking generation units located in Ohio and Indiana. DP&L’s wholly-owned plants and share of the capacity of its jointly-owned plants and DPLE’s wholly-owned peaking units aggregates to approximately 3,817 MW. During the period November 28, 2011 through December 31, 2011, approximately 80% of DP&L’s coal was provided by four suppliers and DP&L has long-term contracts with three of them. DP&L’s customers include residential, commercial, industrial and governmental, which make up 67%, 21% and 12%, respectively, of DP&L’s revenue for the period after acquisition in November 2011.

Generation

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
IPL[1]	USA—IN	Coal/Gas/Oil	3,699	100%	2001
DP&L[2]	USA—OH	Coal/Diesel/Solar	3,817	100%	2011
			7,516		

(1) IPL plants: Eagle Valley, Georgetown, Harding Street and Petersburg.

(2) DP&L wholly-owned plants: Hutchings, Tait Units 1-3 and diesels, Yankee Street, Yankee Solar, Monument and Sidney. DP&L jointly-owned plants: Beckjord Unit 6, Conesville Unit 4, East Bend Unit 2, Killen, Miami Fort Units 7 & 8, Stuart and Zimmer. In addition to the above, DP&L, also owns a 4.9% equity ownership in OVEC, an electric generating company. OVEC has two plants in Cheshire, Ohio and Madison, Indiana with a combined generation capacity of approximately 2,655 MW. DP&L’s share of this generation capacity is approximately 111 MW. DPLE plants: Tait Units 4-7 and Montpelier Units 1-4.

Distribution

Business	Location	Approximate Number of Customers Served as of 12/31/2011	GWh Sold in 2011	AES Equity Interest (Percent, Rounded)	Year Acquired
IPL	USA—IN	470,000	15,647	100%	2001
DP&L[1]	USA—OH	500,000	1,243	100%	2011
		970,000	16,890		

(1) GWh sold from the acquisition on November 28, 2011 through December 31, 2011.

Europe

The following table provides highlights of our Europe operations:

Countries	Bulgaria, Hungary, Jordan, Kazakhstan, Netherlands, Spain, Turkey, Ukraine and the United Kingdom
Generation Capacity	8,779 Gross MW
Utilities Penetration	1.8 million customers (10,862 GWh)
Generation Facilities	19
Utilities Businesses	4
Key Generation Businesses	Maritza, Ballylumford, Kilroot
Key Utilities Businesses	Kievoblenergo and Rivneenergo

Our Utilities operations in Europe are discussed further under Corporate and Other below.

Europe Generation. Our Generation operations in Europe accounted for 9%, 8% and 6% of our consolidated revenue in 2011, 2010 and 2009, respectively. In 2011, our Maritza facility in Bulgaria, a 670 MW coal-fired plant, commenced commercial operations. As a result of the announced sale of 80% of our interest in Cartagena, a 1,199 MW gas-fired plant in Spain, we have classified Cartagena as "held for sale" on the Consolidated Balance Sheets. AES operates four power plants in Kazakhstan which account for 8% of the country's total installed generation capacity. In the United Kingdom, we own and operate more than 1,900 MW at the Ballylumford plant and the Kilroot facility. See Note 16—Segment and Geographic Information in the Consolidated Financial Statements in Item 8 of this Form 10-K for revenue, Adjusted Gross Margin (a non-GAAP measure) and total assets by segment. Key business drivers of this segment are: foreign currency exchange rates, new legislation and regulations including those related to the environment.

Set forth below is a list of our Europe Generation facilities:

Generation

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
Maritza	Bulgaria	Coal	670	100%	2011
Tisza II	Hungary	Gas/Oil	900	100%	1996
Amman East	Jordan	Gas	380	37%	2009
Shulbinsk HPP[(1)]	Kazakhstan	Hydro	702	0%	1997
Sogrinsk CHP	Kazakhstan	Coal	301	100%	1997
Ust—Kamenogorsk HPP[(1)]	Kazakhstan	Hydro	331	0%	1997
Ust—Kamenogorsk CHP	Kazakhstan	Coal	1,354	100%	1997
Elsta[(2)]	Netherlands	Gas	630	50%	1998
Cartagena[(3)]	Spain	Gas	1,199	71%	2006
Damlapinar[(2),(4)]	Turkey	Hydro	16	51%	2010
Girlevik II-Mercan[(2),(4)]	Turkey	Hydro	12	51%	2007
Kepezkaya[(2),(4)]	Turkey	Hydro	28	51%	2010
Yukari-Mercan[(2),(4)]	Turkey	Hydro	14	51%	2007
Kumkoy[(2),(4)]	Turkey	Hydro	18	51%	2011
Bursa[(2),(5)]	Turkey	Gas	156	50%	2011
Kocaeli[(2),(5)]	Turkey	Gas	158	50%	2011
Istanbul (Koc University)[(2),(5)]	Turkey	Gas	2	50%	2011
Ballylumford	United Kingdom	Gas	1,246	100%	2010
Kilroot[(6)]	United Kingdom	Coal/Gas/Oil	662	99%	1992
			8,779		

(1) AES operates these facilities under concession agreements until 2017.
(2) Unconsolidated entities, the results of operations of which are reflected in Equity in Earnings of Affiliates.
(3) In October 2011, the Company met held for sale criteria and expects to dispose of 80% of its interest in this business within the next twelve months. Until the business is sold, it will be reported as a held for sale business on the Consolidated Balance Sheets and reflected in continuing operations on the Consolidated Statements of Operations, as the Company continues to hold an ownership interest in the business.
(4) Joint Venture with I.C. Energy.
(5) Joint Venture with Koc Holding.
(6) Includes Kilroot Open Cycle Gas Turbine ("OCGT").

Asia

Our Asia operations accounted for 4%, 4% and 3% of consolidated revenue in 2011, 2010 and 2009, respectively. Asia's Generation business operates 7 power plants with a total capacity of 3,802 MW in four countries. In Asia, AES operates generation facilities only. See Note 16—*Segment and Geographic Information* in the Consolidated Financial Statements in Item 8 of this Form 10-K for revenue, Adjusted Gross Margin (a non-GAAP measure) and total assets by segment. The following table provides highlights of our Asia operations:

Countries	China, India, the Philippines and Sri Lanka
Generation Capacity	3,802 Gross MW
Utilities Penetration	None
Generation Facilities	8 (including 1 under construction)
Utilities Businesses	None
Key Businesses	Masinloc, Kelanitissa and Yangcheng

Asia Generation. More than half of our generation capacity in Asia is located in China. In 1996, AES joined with Chinese partners to build Yangcheng, the first "coal-by-wire" power plant with the generation capacity of 2,100 MW. In April 2008, the Company completed the purchase of a 92% interest in a 660 MW coal-fired thermal power generation facility in Masinloc, Philippines ("Masinloc").

Set forth below is a list of our generation facilities in Asia:

Generation

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
Chengdu[1]	China	Gas	50	35%	1997
Cili	China	Hydro	25	51%	1994
JHRH[1]	China	Hydro	379	49%	2010
Yangcheng[1]	China	Coal	2,100	25%	2001
OPGC[1]	India	Coal	420	49%	1998
Masinloc	Philippines	Coal	660	92%	2008
Kelanitissa	Sri Lanka	Diesel	168	90%	2003
			3,802		

(1) Unconsolidated entities for which the results of operations are reflected in Equity in Earnings of Affiliates.

Generation under construction

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Expected Year of Commercial Operation
Mong Duong II	Vietnam	Coal	1,200	51%	2015

Corporate and Other

"Corporate and Other" includes the net operating results from our Utilities businesses in Africa and Europe, Africa Generation and Wind Generation and other renewables projects. These operations do not require separate segment disclosure. The following provides additional details about our Utilities businesses in Africa and Europe, Africa generation and Wind Generation, which are reported within "Corporate and Other" for financial reporting purposes.

Europe Utilities. Our distribution businesses in the Ukraine and Kazakhstan together serve approximately 1.8 million customers.

Distribution

Business	Location	Approximate Number of Customers Served as of 12/31/2011	GWh Sold in 2011	AES Equity Interest (Percent, Rounded)	Year Acquired
Eastern Kazakhstan REC[(1),(2),(3)]	Kazakhstan	459,000	3,444	0%	
Ust-Kamenogorsk Heat Nets[(1),(4)]	Kazakhstan	96,000	—	0%	
Kievoblenergo	Ukraine	874,000	5,079	89%	2001
Rivneenergo	Ukraine	409,000	2,339	84%	2001
		1,838,000	10,862		

(1) AES operates these businesses through management agreements and owns no equity interest in these businesses.

(2) In November 2011, AES sent notification to the Kazakhstan Government regarding the early termination of the management agreement for these companies. Transfer of management rights to the Kazakhstan Government should be completed within 180 days.

(3) Shygys Energo Trade, a retail electricity company, is 100% owned by Eastern Kazakhstan REC ("EK REC") and purchases distribution service from EK REC and electricity in the wholesale electricity market and resells to the distribution customers of EK REC.

(4) Ust-Kamenogorsk Heat Nets provide transmission and distribution of heat with a total heat generating capacity of 224 Gcal.

Africa Utilities. AES owns a 56% interest in an integrated utility, Société Nationale d'Electricité ("Sonel"). Sonel generates, transmits and distributes electricity to over half a million people and is the sole distributor of electricity in Cameroon.

Set forth below is a list of the generation and distribution facilities of Sonel:

Sonel's generation facilities

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
Sonel[(1)]	Cameroon	Hydro/Diesel/Heavy Fuel Oil	936	56%	2001

(1) Sonel plants: Bafoussam, Bassa, Djamboutou, Edéa, Lagdo, Limbé, Logbaba I, Logbaba II, Oyomabang I, Oyomabang II, Song Loulou, and other small remote network units.

Sonel's distribution facility

Business	Location	Approximate Number of Customers Served as of 12/31/2011	GWh Sold in 2011	AES Equity Interest (Percent, Rounded)	Year Acquired
Sonel	Cameroon	660,000	3,345	56%	2001

Africa Generation. Set forth below is a list of our generation facilities in Africa:

Generation

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
Dibamba	Cameroon	Heavy Fuel Oil	86	56%	2009
Ebute	Nigeria	Gas	294	95%	2001
			380		

Generation under construction

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Expected Year of Commercial Operations
Kribi	Cameroon	Gas	216	56%	2013

Wind Generation. We own and operate 1,616 MW of wind generation capacity and operate an additional 134 MW of capacity through operating and management agreements. Our wind business is located primarily in North America where we operate wind generation facilities that have generation capacity of 1,266 MW.

Set forth below is a list of Wind Generation facilities:

Generation

Business	Location	Power Source	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
St. Nikola	Bulgaria	Wind	156	89%	2010
Dong Qi[(1),(2)]	China	Wind	49	49%	2010
Huanghua I[(1),(2)]	China	Wind	49	49%	2009
Huanghua II[(1),(2)]	China	Wind	49	49%	2010
Hulunbeier[(1),(2)]	China	Wind	49	49%	2008
InnoVent[(2),(3)]	France	Wind	75	40%	2003-2009
St. Patrick	France	Wind	35	100%	2010
North Rhins	Scotland	Wind	22	100%	2010
Altamont	USA—CA	Wind	40	100%	2005
Mountain View I & II[(4)]	USA—CA	Wind	67	100%	2008
Palm Springs	USA—CA	Wind	30	100%	2005
Tehachapi	USA—CA	Wind	38	100%	2006
Storm Lake II[(4)]	USA—IA	Wind	78	100%	2007
Lake Benton I[(4)]	USA—MN	Wind	106	100%	2007
Condon[(4)]	USA—OR	Wind	50	100%	2005
Armenia Mountain[(4)]	USA—PA	Wind	101	100%	2009
Buffalo Gap I[(4)]	USA—TX	Wind	121	100%	2006
Buffalo Gap II[(4)]	USA—TX	Wind	233	100%	2007
Buffalo Gap III[(4)]	USA—TX	Wind	170	100%	2008
Laurel Mountain	USA—WV	Wind	98	100%	2011
Wind generation facilities[(5)]	USA	Wind	134	0%	2005
			1,750		

(1) Joint Venture with Guohua Energy Investment Co. Ltd.

(2) Unconsolidated entities for which the results of operations are reflected in Equity in Earnings of Affiliates.

(3) InnoVent plants: Bignan, Chepy, Croixrault-Moyencourt, Eurotunel, Frenouville, Gapree, Grand Fougeray, Guehenno, Hargicourt, Hescamps, LePortal, Les Diagots, Nibas, Plechatel, Saint-Hilaire la Croix and Valhoun. InnoVent owns various percentages of underlying projects.

(4) AES owns these assets together with third party tax equity investors with variable ownership interests. The tax equity investors receive a portion of the economic attributes of the facilities, including tax attributes that vary over the life of the projects. The proceeds from the issuance of tax equity are recorded as Noncontrolling Interest in the Company's Consolidated Balance Sheets.

(5) AES operates these facilities through management or O&M agreements and owns no equity interest in these businesses.

Wind Generation projects under construction

Business	Location	Power Source	Gross MW	AES Equity Interest (Percent, Rounded)	Expected Year of Commercial Operation
InnoVent[1]	France	Wind	39	40%	2012
Chen Qi[2]	China	Wind	49	49%	2012
Saurashtra	India	Wind	39	100%	2012
Drone Hill	United Kingdom	Wind	29	100%	2012
Mountain View IV	US-CA	Wind	49	100%	2012
			205		

(1) InnoVent plants: Allery, Audrieu, Lamballe, Lefaux and Vron. InnoVent owns various percentages of underlying projects.

(2) Joint Venture with Guohua Energy Investment Co. Ltd.

Other. 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 and gross margin. AES Solar was formed in March 2008 to develop, own and operate solar installations. Since its launch, AES Solar has commenced commercial operations of 151 MW of solar projects in Bulgaria, France, Greece, Italy and Spain; and has 106 MW under construction in Bulgaria, France, Greece, India, Italy and the U.S.

"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. See Note 16—Segment and Geographic Information in the Consolidated Financial Statements in Item 8 of this Form 10-K for information on revenue from external customers, Adjusted Gross Margin (a non-GAAP measure) and total assets by segment.

Financial Data by Country

The table below presents information, by country, about our consolidated operations for each of the three years ended December 31, 2011, 2010 and 2009, respectively, and property, plant and equipment as of December 31, 2011 and 2010, respectively. Revenue is recognized in the country in which it is earned and assets are reflected in the country in which they are located.

	Revenue			Property, Plant & Equipment, net	
	2011	2010	2009	2011	2010
	(in millions)				
United States[1]	$ 2,256	$ 2,095	$ 1,987	$ 8,448	$ 6,027
Non-U.S.:					
Brazil[2]	6,640	6,355	5,292	5,896	6,263
Chile	1,608	1,355	1,239	2,781	2,560
Argentina[3]	979	771	571	279	270
El Salvador	752	648	619	268	261
Dominican Republic	674	535	429	662	625
United Kingdom[4]	587	364	228	523	507
Philippines	480	501	250	766	784
Ukraine	418	356	286	94	86
Mexico	404	409	329	774	786
Cameroon	386	422	370	901	823
Colombia	365	393	347	384	387
Puerto Rico	298	253	267	581	596
Spain[5]	258	411	—	—	—
Bulgaria[6]	251	44	—	1,619	1,825
Hungary[7]	204	252	259	6	73
Panama	189	194	168	1,040	921
Kazakhstan	145	138	123	86	63
Sri Lanka	140	100	109	22	69
Jordan	124	120	104	216	224
Qatar[8]	—	—	—	—	—
Pakistan[9]	—	—	—	—	—
Oman[10]	—	—	—	—	—
Other Non-U.S.[11]	116	112	133	385	279
Total Non-U.S.	15,018	13,733	11,123	17,283	17,402
Total	$17,274	$15,828	$13,110	$25,731	$23,429

(1) Excludes revenue of $228 million, $519 million and $559 million for the years ended December 31, 2011, 2010 and 2009, respectively, and property, plant and equipment of $140 million as of December 31, 2010, related to Eastern Energy and Thames, which were reflected as discontinued operations and businesses held for sale in the accompanying Consolidated Statements of Operations and Consolidated Balance Sheets.

(2) Excludes revenue of $124 million, $118 million and $102 million for the years ended December 31, 2011, 2010 and 2009, respectively, and property, plant and equipment of $151 million as of December 31, 2010, related to Brazil Telecom, which was reflected as discontinued operations and businesses held for sale in the accompanying Consolidated Statements of Operations and Consolidated Balance Sheets.

(3) Excludes revenue of $102 million, $116 million and $113 million for the years ended December 31, 2011, 2010 and 2009, respectively, and property, plant and equipment of $189 million as of December 31, 2010, related to our Argentina distribution businesses, which were reflected as discontinued operations and businesses held for sale in the accompanying Consolidated Statements of Operations and Consolidated Balance Sheets.

(4) Excludes revenue of $17 million, $21 million and $11 million for the years ended December 31, 2011, 2010 and 2009, respectively, and property, plant and equipment of $20 million as of December 31, 2010, related to carbon reduction projects, which were reflected as discontinued operations and businesses held for sale in the accompanying Consolidated Statements of Operations and Consolidated Balance Sheets.
(5) Excludes property, plant and equipment of $620 million and $667 million as of December 31, 2011 and 2010, respectively, related to Cartagena, which was reflected as businesses held for sale in the accompanying Consolidated Balance Sheets.
(6) Maritza and our wind project in Bulgaria were under development and therefore not operational as of December 31, 2009. Our wind project in Bulgaria started operations in 2010 and Maritza started operations in June 2011.
(7) Excludes revenue of $14 million, $44 million and $58 million for the years ended December 31, 2011, 2010 and 2009, respectively, and property, plant and equipment of $7 million as of December 31, 2010, related to Borsod and Tiszapalkonya, which were reflected as discontinued operations and businesses held for sale in the accompanying Consolidated Statements of Operations and Consolidated Balance Sheets.
(8) Excludes revenue of $129 million and $163 million for the years ended December 31, 2010 and 2009, respectively, related to Ras Laffan, which was reflected as discontinued operations and businesses held for sale in the accompanying Consolidated Statements of Operations.
(9) Excludes revenue of $299 million and $470 million for the years ended December 31, 2010 and 2009, respectively, related to Lal Pir and Pak Gen, which were reflected as discontinued operations and businesses held for sale in the accompanying Consolidated Statements of Operations.
(10) Excludes revenue of $62 million and $101 million for the years ended December 31, 2010 and 2009, respectively, related to Barka, which was reflected as discontinued operations and businesses held for sale in the accompanying Consolidated Statements of Operations.
(11) Excludes revenue of $1 million for the year ended December 31, 2011, and property, plant and equipment of $2 million and $18 million as of December 31, 2011, and 2010, respectively, related to alternative energy and carbon reduction projects, which were reflected as discontinued operations and businesses held for sale in the accompanying Consolidated Statements of Operations and Consolidated Balance Sheets.

Customers

We sell to a wide variety of customers. No individual customer accounted for 10% or more of our 2011 total revenue. In our generation business, we own and/or operate power plants to generate and sell power to wholesale customers such as utilities and other intermediaries. Our utilities sell to end-user customers in the residential, commercial, industrial and governmental sectors in a defined service area.

Employees

As of December 31, 2011, we employed approximately 27,000 people.

Executive Officers

The following individuals are our executive officers:

Andrés R. Gluski, 54 years old, has been President, Chief Executive Officer ("CEO") and a member of our Board of Directors since September 2011. Prior to assuming his current position, Mr. Gluski served as Executive Vice President and Chief Operating Officer ("COO") of the Company since March 2007. Prior to becoming the COO of AES, Mr. Gluski was Executive Vice President and the Regional President of Latin America from 2006 to 2007. Mr. Gluski was Senior Vice President for the Caribbean and Central America from 2003 to 2006, CEO of La Electricidad de Caracas ("EDC") from 2002 to 2003 and CEO of AES Gener (Chile) in 2001. Prior to joining AES in 2000, Mr. Gluski was Executive Vice President and CFO of EDC, Executive Vice President of Banco de Venezuela (Grupo Santander), Vice President for Santander Investment, and Executive Vice President and CFO of CANTV (subsidiary of GTE). Mr. Gluski has also worked with the International Monetary Fund in the Treasury and Latin American Departments and served as Director General of the Ministry of Finance of

Venezuela. Mr. Gluski is also Chairman of AES Gener and AES Brasiliana and serves on the Boards of two AES joint ventures: AES Entek, a joint venture between AES and Koc Holdings that will develop and operate power projects in Turkey and AES Solar, a joint venture between AES and Riverstone Holdings LLC. Mr. Gluski is also on the Boards of Cliffs Natural Resources, The Council of Americas, US Spain Business Council and The Edison Electric Institute. Mr. Gluski is a graduate of Wake Forest University and holds an M.A and a Ph.D. in Economics from the University of Virginia.

Ned Hall, 52 years old, has been Chief Operating Officer, Global Generation, and Executive Vice President since October of 2011. Prior to assuming his current position, Mr. Hall was Executive Vice President, Regional President for North America and Chairman, Global Wind Generation and Energy Storage since June 2008. In August of 2009, Mr. Hall joined the Board of AES Solar, a joint venture between AES and Riverstone Holdings LLC. Mr. Hall is also a director on the AES Gener and AES Entek Boards. Prior to his current position, Mr. Hall was Vice President of the Company and President, Global Wind Generation from April 2005 to June 2008, Managing Director of AES Global Development from September 2003 to April 2005, and was an AES Group Manager from April 2001 to September 2003. Mr. Hall joined AES in 1988 as a Project Manager working in the Development Group and has held a variety of development and operating roles for AES, including assignments in the U.S., Europe, Asia and Latin America. He is a registered professional engineer in the Commonwealth of Massachusetts. Mr. Hall holds a BSME degree from Tufts University and an MBA degree in finance/operations management from the MIT Sloan School of Management.

Victoria D. Harker, 47 years old, has been an Executive Vice President and Chief Financial Officer ("CFO") since January 2006. In 2011, she also became President, Global Business Services. Prior to joining the Company, Ms. Harker held the positions of Acting CFO, Senior Vice President and Treasurer of MCI from November 2002 to January 2006. Prior to that, Ms. Harker served as CFO of MCI Group, a unit of WorldCom Inc., from 1998 to 2002. Prior to 1998, Ms. Harker held several positions at MCI in the areas of finance, information technology and operations. In November of 2009, she was elected to the board of directors of Darden Restaurants, Inc. and in 2011 she was elected as a Director of Xylem, Inc. She has also been a member of the University of Virginia Board of Managers since 2007 and the board of the Wolf Trap Foundation for the Performing Arts since 2009. Ms. Harker received a Bachelor of Arts degree in English and Economics from the University of Virginia and a Masters in Business Administration, Finance from American University.

Brian A. Miller, 46 years old, is an Executive Vice President of the Company, General Counsel, and Corporate Secretary. Mr. Miller joined the Company in 2001 and has served in various positions including Vice President, Deputy General Counsel, Corporate Secretary, General Counsel for North America and Assistant General Counsel. In March of 2008, Mr. Miller joined the Board of AES Solar Energy, Ltd. and AES Solar Power, LLC, joint ventures between AES and Riverstone Holdings LLC. In 2009, he joined the board of AgCert International Limited and AgCert Canada Holding Limited. In 2010, Mr. Miller joined the Board of AES Entek, a joint venture that will develop and operate power projects in Turkey, between AES and Koc Holdings. In November of 2011, Mr. Miller joined the Board of DPL Inc., owner of Dayton Power & Light Company. Prior to joining AES, he was an attorney with the law firm Chadbourne & Parke, LLP. Mr. Miller received a bachelor's degree in History and Economics from Boston College and holds a Juris Doctorate from the University of Connecticut School Of Law.

Rita Trehan, 44 years old, is Vice President of Human Resources and Internal Communications, Safety and AES Performance Excellence (APEX), the Company's worldwide performance improvement program since 2011. Prior to her current position, Ms. Trehan served as Vice President, Human Resources and Internal Communications from 2008 to 2011 and Vice President, People and Learning from 2005 to 2008. She has served on the Board of Directors for AES Sonel in Cameroon since 2004. Ms. Trehan joined AES in 2003 as Director of Learning and People Development. Before joining AES, Ms. Trehan held a number of senior human resources leadership positions at Honeywell International, including Global Human Resources Director for the Sensing & Controls Division. Ms. Trehan also served in various corporate and global human resources business roles during her 15 years at Honeywell. Ms. Trehan holds a Bachelor of Science in Sociology from Brunel University in Middlesex, UK and a postgraduate diploma from the Institute of Personnel Management.

Andrew Vesey, 56 years old, has been Chief Operating Officer, Global Utilities, and Executive Vice President since October of 2011. Prior to assuming his current position, Mr. Vesey was Executive Vice President and Regional President of Latin America and Africa since April of 2009, Executive Vice President and Regional President for Latin America from March 2008 through March 2009, and Chief Operating Officer for Latin America from July 2007 through February 2008. Mr. Vesey also served as Vice President and Group Manager for AES Latin America, DR-CAFTA Region, Vice President of the Global Business Transformation Group, and Vice President of the Integrated Utilities Development Group. Mr. Vesey is also Chairman of the AES Sul, AES Tiete, IPL, IPALCO, DPL, DP&L Boards and serves on the Boards of AES Sonel, Brasiliana, and ELPA. In addition, Mr. Vesey is a member of the Board of the Corporate Council of Africa, Trust for the Americas, and the Institute of the Americas. Prior to joining AES in 2004, Mr. Vesey was a Managing Director of the Utility Finance and Regulatory Advisory Practice at FTI Consulting Inc., a partner in the Energy, Chemicals and Utilities Practice of Ernst & Young LLP, and CEO and Managing Director of Citipower Pty of Melbourne, Australia. He received his BA in Economics and a BS in Mechanical Engineering from Union College in Schenectady, New York and his MS from New York University.

Gardner W. Walkup Jr., 52 years old, has been AES' Vice President of Strategy since 2010. Mr. Walkup has more than 25 years of energy industry experience. Between 2007 and 2010, he served as Vice President and Managing Director at IHS Cambridge Energy Research Associates where he led the Energy and Natural Resources consulting practice that provided strategy development services to clients globally. He held similar leadership roles at a number of business consulting firms including Strategic Decisions Group, PricewaterhouseCoopers and Applied Decision Analysis. In addition, he worked at Chevron for approximately 15 years in a variety of positions, including strategic planning, operations, and research and development. Mr. Walkup has a B.S. in Chemical Engineering from the University of California at Davis and a M.S. in Petroleum Engineering from Stanford University.

How to Contact AES and Sources of Other Information

Our principal offices are located at 4300 Wilson Boulevard, Arlington, Virginia 22203. Our telephone number is (703) 522-1315. Our website address is *http://www.aes.com*. Our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K and any amendments to such reports filed pursuant to Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934 (the "Exchange Act") are posted on our website. After the reports are filed with, or furnished to, the Securities and Exchange Commission ("SEC"), they are available from us free of charge. Material contained on our website is not part of and is not incorporated by reference in this Form 10-K. You may also read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet website that contains the reports, proxy and information statements and other information that we file electronically with the SEC at www.sec.gov.

Our CEO and our CFO have provided certifications to the SEC as required by Section 302 of the Sarbanes-Oxley Act of 2002. These certifications are included as exhibits to this Annual Report on Form 10-K.

Our CEO provided a certification pursuant to Section 303A of the New York Stock Exchange Listed Company Manual on May 12, 2011.

Our Code of Business Conduct ("Code of Conduct") and Corporate Governance Guidelines have been adopted by our Board of Directors. The Code of Conduct is intended to govern, as a requirement of employment, the actions of everyone who works at AES, including employees of our subsidiaries and affiliates. Our Ethics and Compliance Department provides training, information, and certification programs for AES employees related to the Code of Conduct. The Ethics and Compliance Department also has programs in place to prevent and detect criminal conduct, promote an organizational culture that encourages ethical behavior and a commitment to compliance with the law, and to monitor and enforce AES policies on corruption, bribery, money laundering and associations with terrorists groups. The Code of Conduct and the Corporate Governance Guidelines are located in their entirety on our website at *http://www.aes.com*. Any person may obtain a copy of the Code of Conduct or the Corporate Governance Guidelines without charge by making a written request to: Corporate Secretary, The AES Corporation, 4300 Wilson Boulevard, Arlington, VA 22203. If any amendments to, or waivers from, the Code of Conduct or the Corporate Governance Guidelines are made, we will disclose such amendments or waivers on our website.

Regulatory Matters

Overview

In each country where we conduct business, we are subject to extensive and complex governmental regulations that affect most aspects of our business, such as regulations governing the generation and distribution of electricity and environmental regulations. These regulations affect the operation, development, growth and ownership of our businesses. Regulations differ on a country-by-country basis and are based upon the type of business we operate in a particular country.

Regulation of our Generation Businesses

Our Generation businesses operate in two different types of regulatory environments: Market Environments and Other Environments.

Market Environments. In market environments, sales of electricity may be made directly on the spot market, under negotiated bilateral contracts, or pursuant to PPAs. The spot markets are typically administered by a central dispatch or system operator that seeks to optimize the use of the generation resources throughout an interconnected system. The spot price is usually set at the marginal cost of energy (the cost of the least expensive next-generation plant required to meet system demand) or based on bid prices. In addition, many of these wholesale markets include markets for ancillary services to support the reliable operation of the transmission system, such as regulation (a service that corrects for short-term changes in electricity use that could impact the stability of the power system). Most of our businesses in Europe, Latin America and the United States operate in these types of liberalized markets.

Other Environments. We operate Generation assets in certain countries that do not have a spot market. In these environments, electricity is sold only through PPAs with state-owned entities and/or industrial clients as the offtaker. Examples of countries where we operate in this type of environment include Jordan, Nigeria, Puerto Rico and Sri Lanka.

Regulation of our Distribution Businesses

In general, our distribution companies sell electricity directly to end-users such as homes and businesses and bill customers directly. The amount that our distribution companies can charge customers for electricity is governed by a regulated tariff. The tariff, in turn, is generally based upon a certain usage level that includes a pass-through to the customer of costs that are not controlled by the distribution company, including the costs of fuel (in the case of integrated utilities) and/or the costs of purchased energy, plus a margin for the value added by the distributor, which is usually calculated as a fair return on the fair value of the company's assets. This regulated tariff is periodically reviewed and reset by the applicable regulatory agency. Components of the tariff that are directly passed through to the customer are usually adjusted through an automated process. In many instances, the tariffs can be adjusted between scheduled regulatory resets pursuant to an inflation adjustment or another index. Customers with demand above a certain level are often unregulated and can choose to contract with generation companies directly and pay a wheeling fee, which is a fee to the distribution company for use of the distribution system. Most of our utilities operate as monopolies within exclusive geographic areas set by the regulatory agency and face limited competition from other distributors.

Set forth below is a discussion of certain regulations under which we operate in the countries where we do business. In each country, the regulatory environment can pose material risks to our business, operations or financial condition. For further discussion of those risks, see the Item 1A.—Risk Factors of this Form 10-K.

Latin America and Africa

Argentina

Structure of Electricity Market. The Argentine electricity market is divided into three separate lines of business: generation, transmission and distribution. AES Argentina operates 11% of the installed capacity of the Wholesale Electricity Market ("WEM"). The law recognizes a category of large users made up of industrial companies and other consumers with substantial electricity supply needs.

The WEM is comprised of:

- A Term Contracts Market, with contracts freely agreed amongst producers and consumers;
- A Spot Market, with prices sanctioned on an hourly basis considering the economic cost of production represented by the short-term marginal cost (spot prices); and
- A Stabilization System on a quarterly basis of the prices forecasted for the spot market, created for the purchase of the distributors (seasonal prices).

Principal Regulators. The National Electricity Regulating Agency ("ENRE") is responsible for ensuring that transmission and distribution companies comply with the concessions granted by the Argentine government and approving distribution tariffs. The WEM is managed by Compañía Administradora del Mercado Mayorista Eléctrico, Sociedad Anónima ("CAMMESA"), the independent system operator. CAMMESA also acts as the dispatch entity, or OED (Organismo Encargado de Desapacho), and manages the organization, dispatch and operations of the WEM at large according to the policies established by the Energy Secretariat, under the Ministry of Federal Planning, Public Investment and Services. In this capacity, CAMMESA is empowered to interpret the rules relating to the organization, dispatch and energy agreements in the WEM. In addition to these duties, CAMMESA manages the information on supply and demand in the WEM, which is used by the Energy Secretariat to fix the seasonal prices and the market's operational rules. CAMMESA's operating costs are borne by the WEM's participants and agents.

Principal Regulations. The electricity sector activities are regulated by the Electricity Act. Law 24.065 and Law 11.796 regulate the activities of generation, transmission and distribution of electric energy in the territory of the Province of Buenos Aires, determining that the activities of transmission and distribution of energy are public services, while the generation is an activity of general interest.

Currently, the price of electric energy is determined assuming all generating units in Argentina are operating with natural gas, even though the generators may be using more expensive, alternative fuels. In the case of generators using alternative fuels, CAMMESA pays the total variable cost of production, which may exceed the established spot price. Additionally, in the spot market, generators are also remunerated for their capacity to generate electricity in excess of supply agreements or private contracts executed by them.

The Argentine government has adopted many new economic measures since 2002, by means of the "Emergency Law" 25561, as amended and extended by various supplemental laws and regulations. These laws and regulations effectively terminated the use of the United States Dollar as the functional currency of the Argentine electricity sector.

Environmental Regulations. All electricity facilities are regulated by federal and local laws and regulations. The main federal acts are the following: the General Environmental Act 25.675, the Industrial Disposals Act: 25.612, the Standards for handling and elimination of PCBs 25670, and the Harmful Wastes Act, 24051. Within the Province of Buenos Aires, the principal acts are: the General Environmental Law 13.516 and the Industrial and Special Wastes Act 13.515. These main laws are complemented by several federal and local decrees and resolutions. The main authorities responsible for environmental regulation related to our businesses are: the National and Provincial Ministers of Public Health and Environment, the Federal and the Provincial Secretaries of Environment and Sustainable Development; and the National Electricity Regulatory Commission.

Material Regulatory Actions. During 2004, the Energy Secretariat reached agreements with natural gas and electricity producers to reform the energy markets. In the electricity sector, the Energy Secretariat passed Resolution 826/2004, inviting generators to contribute a percentage of their sales margins to fund the development and construction of two new combined cycle power plants to be installed by 2008/2009 ("FONINVEMEM I & II"). The time period for the funding was set from January 2004 through December 2006 and was subsequently extended through December 2007. During 2008, both power plants started operation of the gas turbines, and since March 2010, the plants started operations in combined cycle mode after receiving commercial habilitation. In exchange, the Argentine government committed to reform market regulation to match more favorable regulations that existed prior to 2001. Additionally, participating generators will receive a pro rata ownership share in the new generation plants for ten years. Since March 2010, our participating generation companies are collecting their sales margin contributed for the construction of the facilities in monthly installments.

A general agreement with the rest of the Generators operating in Argentina and the government was signed on November 25, 2010 to address a nation-wide problem of overdue accounts receivable in the generation market. The agreement established the guidelines for the detailed documentation that will allow the execution of the FONINVEMEM III project agreement and some additional cash revenues. Under the agreement, accounts receivable accrued for Alicura (our subsidiary) from July 2009 to December 2011, for an amount of approximately $170 million, will be converted into a generation asset to be built under the FONINVEMEM III project. The government will provide the funds necessary to finance the project. The plant will have a PPA with CAMMESA for ten years, calculated to recover 100% of the receivables invested plus a margin of LIBOR + 5%. Payments will be made once the project begins operations. We expect the existing FONINVEMEM I & II documents will be taken as a basis for the future contracts; assuming this, the collection of the 120 payments will not be tied to the availability of the plant. Availability risk will be assumed by the operator through a Long-Term Service Agreement ("LTSA"). Some penalties may apply to the generating companies, but only in those cases where the unavailability is caused by their operating decisions not considered in the LTSA. The yearly penalty would be capped at 10% of the yearly amount required under the PPA.

As a result of the above mentioned agreement, AES incorporated a new controlled company ("Central Termoelectrica Guillermo Brown S.A.") that will manage the construction of a new 300MW power plant to be located in the south of the Province of Buenos Aires. During 2012, the execution of an EPC agreement with the selected bidder is expected to complete the construction of the new plant by 2013 and to start commercial operations by October 2013.

Brazil

Structure of Electricity Market. In Brazil, there are two contracting environments that regulate PPAs: the Regulated Contracting Environment ("ACR"), for the Generation and Distribution of Electric Power Agents, and the Free Contracting Environment ("ACL"), for the Generation, Commercialization, Importers and Exporters of Energy Power Agents as well as consumers.

This model establishes a number of requirements to be followed by the participants in the industry, such as the obligation for distributors to contract for their market growth years in advance only through regulated auctions; hydro and thermal energy contracting conditions to ensure better balance between supply cost and system stability; and a permanent supply monitoring structure to detect possible imbalances between supply and demand.

Principal Regulators. In Brazil, there are a number of institutions that govern the electricity sector including the Brazilian Electricity Regulatory Agency ("ANEEL"), the National System Operator ("ONS") and the Electrical Energy Commercialization Chamber ("CCEE").

ANEEL's responsibilities are to regulate and inspect production, transmission, distribution and commercialization of electricity in order to assure quality of provided services and universal access. ANEEL is also responsible for the establishment of tariffs for end consumers, in a way that the economic and financial feasibility of power sector participants as Generation, Transmission and Distribution companies and the industry as a whole is preserved. The changes brought about in 2004 by the new model made ANEEL responsible for promoting, directly or indirectly, auctions for the Distribution companies to purchase energy through long-term contracts within the National Interconnected System (Sistema Interligado Nacional) ("SIN").

The paramount obligations of the CCEE (formerly, the Wholesale Energy Market) include: the determination of the Differences' Price Settlement (Preço de Liquidação de Diferenças) ("PLD"), or Spot Price, used to value short-term market transactions; the execution of the energy accounting process, identifying who and how much electricity is involved in multilateral short-term market transactions; the financial settlement of the amounts calculated in the energy accounting process; and preparation and execution of energy auctions within the ACR by ANEEL's delegation process.

Principal Regulations.

Distribution Companies. AES has two distribution businesses in Brazil: AES Eletropaulo and AES Sul. Under the power sector model, distribution companies have to purchase electricity at the regulated market through auctions. Every distribution utility is obligated to contract to meet 100% of its energy needs in the ACR. Self-dealing is no longer allowed; however, existing bilateral contracts are being honored but cannot be renewed. The tariff charged by distribution companies to captive customers is composed of a nonmanageable cost component ("Parcel A"), which includes energy purchase costs and charges related to the use of transmission and distribution systems and is for the most part directly passed through to customers, and a manageable cost component ("Parcel B"), which includes operation and maintenance costs defined by ANEEL, recovery of assets and a component for the value added by the distributor (calculated as the net asset base multiplied by the pre-tax weighted average cost of capital). Parcel B is reset every four years for AES Eletropaulo and every five years for AES Sul. There is an annual tariff adjustment to pass through Parcel A costs to customers and to adjust the Parcel B costs by inflation, less an efficiency factor. Distribution companies could also be entitled to extraordinary tariff revisions in the event of significant changes to their cost structure.

In the first half of 2010, all distribution companies signed amendments to the Concession Contracts, capturing market variance effects over sector charges. AES Eletropaulo signed its amendment on May 3, while AES Sul signed it on April 12.

Generation Companies. AES has two generation businesses in Brazil: AES Tietê and AES Uruguaiana. Under the power sector model, the Ministry of Mines and Energy ("MME") determines the maximum amount of energy to be sold through contracts by each plant known as "assured energy" or the amount of energy representing the long-term average of the expected energy production of the plant defined by ANEEL.

AES Tietê must provide physical coverage, i.e. its assured energy from its own power generation or purchase contracts to cover 100% of its sales contracts. The failure to provide the required physical coverage and/or present purchase contracts, which is subject to monthly verification, exposes the generation company to the payment of penalties, which could be material. At this time, all of AES Tiete's assured energy has been sold to AES Eletropaulo. The PPA entered into with AES Eletropaulo, which expires on December 31, 2015, and requires that the price of energy sold be adjusted annually based on the Brazilian inflation variation. Before the end of the PPA in 2015, AES Tietê must seek alternatives to the immediate recontracting of its assured energy from 2016 onwards. Existing legislation allows AES Tietê to allocate its energy to the regulated auctions of existing energy, or through bilateral contracts for private clients.

In addition, the State of São Paulo established some conditions to privatize the generation sector in São Paulo state including an obligation for the winners of the bid to increase their generation capacity by 15%, originally to be accomplished by the end of 2007. AES Tietê, as well as other concessionaire generators, was not able to meet this requirement due to regulatory, environmental, hydrological and fuel constraints. Although AES Tietê has addressed the issue with the State of São Paulo in order to make the obligation viable under the new business, regulatory, and sectional reality, in August 2011, the State of São Paulo filed a lawsuit seeking to compel AES Tietê to expand its generation capacity by 15% or pay unspecified damages. In that case, the State of São Paulo sought and received an injunction from the first instance court requiring AES Tietê to present its plan on how it intended to fulfill its obligation to expand its capacity. AES Tietê has appealed the injunction and the matter is ongoing. AES Tietê has developed a 550 MW gas-fired thermal power project called Termo São Paulo in order to meet this obligation of 398 MW in its installed capacity. AES Tietê is also analyzing other wind, thermo and hydro projects in order to expand its generation. Compliance with these rules could have a material impact on the Company.

Environmental Regulations. Electric sector companies are subject to strict federal, state and municipal environmental legislation and regulations, relating to atmospheric emissions and specially protected areas. Such companies depend on permits and authorizations from government bodies in order to conduct their activities. In the event of a violation or noncompliance with such laws, regulations, permits and authorizations, the company may suffer administrative sanctions such as fines, shutdown of activities, as well as revocations or invalidations of its permits and authorizations. In addition, the Public Prosecutor's Office may initiate both civil and criminal investigations and lawsuits against a company and its agents that are not in compliance with such laws, regulations, permits and authorizations, which may result in indemnities and penalties. In addition, government agencies and other public authorities may delay the issuance of permits and necessary authorizations for the development of power companies causing project implementation delays and, consequently, unfavorable effects in the companies' businesses and results. Any such action by the government agencies may negatively affect businesses in the power sector and have adverse effects on the business and results of the companies, including our subsidiaries in Brazil.

In 2011, a new Forestry Code bill was submitted to the Brazilian Congress for approval. The Forestry Code bill provides for new rules regarding the use of the land and forests, such as the maximum extension of specially protected areas and the dismissal to reserve a specific area to be permanently preserved for generation companies. The impact of the new rule on the energy sector depends on the final drafting of the bill which is currently under discussion.

Material Regulatory Actions. On May 16, 2002, ANEEL issued Order #288, a regulation that established the retroactive denial of the choice of not participating in the "exposition relief mechanism," a mechanism that allowed the sale of energy from Itaipu Generating Co. in the spot market. Due to its negative impact, AES Sul filed a lawsuit seeking the annulment of Order #288. For a further discussion of this dispute see Item 3.—Legal Proceedings in this Form 10-K.

Potential or Proposed Regulations. AES Sul's third tariff reset process will occur in 2013. AES Eletropaulo's tariff reset contractual date was originally in July 2011, but due to ANEEL's delay in defining third cycle methodology, the process was postponed to 2012. AES Eletropaulo's new tariffs, arising from the tariff reset process, will produce retroactive effects on revenues as of July 4, 2011. Based on the best available information currently available, AES Eletropaulo has recorded a regulatory liability of $190 million related to effects from July 2011 to December 2011. However, the ultimate impact on AES Eletropaulo's results will not be determined until the methodology regarding the third cycle of tariff reset is fully defined, disclosed and applied to AES Eletropaulo and the regulatory asset base for AES Eletropaulo is approved by ANEEL. It is possible that the final methodology may be less favorable than we anticipate, which could have a material adverse effect on our results of operations.

Cameroon

Structure of Electricity Market. Our subsidiaries in Cameroon are involved in the generation, transmission, distribution and sale of electricity through AES SONEL, Dibamba Power Development Company ("DPDC") and Kribi Power Development Company ("KPDC"). AES SONEL is an integrated utility that operates approximately 930 MW of generation capacity, two interconnected transmission networks and distributes electricity to approximately 700,000 customers under a 20-year concession agreement that was signed in July 2001. AES SONEL has the exclusive distribution rights to all medium voltage and low voltage customers, except for customers with an installed capacity of more than 1 MW ("Major Customers") who are free to negotiate bilateral agreements. Generation in Cameroon is open to competition and our subsidiary, DPDC, developed, built and is currently operating an 86 MW heavy fuel oil power plant near Douala as an IPP, which provides power to AES SONEL under a tolling agreement. In order to meet increasing demand for power, the government is developing the Lom Pangar Dam project on the Sanaga River, which will increase the flow of the Sanaga River and increase the generation capacity of the two major hydroelectric power plants currently operated by AES SONEL. The Lom Pangar Dam will also generate 50 MW. Another AES subsidiary, KPDC, is currently building a 216 MW gas-fired power plant in Kribi as another IPP, which will provide power to AES SONEL under a power purchase agreement.

Under its Concession Agreement, AES SONEL operates the two interconnected transmission networks in the country: the Southern Grid with a length of 1550 km and the Northern Grid with a length of 665 km. Major customers, distributors, or vendors can access the grid subject to paying a fee. Sales to low voltage and medium voltage customers are subject to tariff levels agreed to between AES SONEL and the regulator based on the framework established in the AES SONEL Concession Agreement. Management of energy flow on the transmission network is currently undertaken by AES SONEL. Under the concession requirements, AES SONEL will be required to create a separate legal entity under which the transmission system will operate. Under the current regulation, such entity is deemed to be a wholly-owned subsidiary of AES SONEL whose share capital will be opened up to other operators in the sector in accordance with procedures to be approved by the regulator.

Principal Regulators. Cameroon's electricity regulatory agency, ARSEL, has functional and decision-making autonomy, and is run by a Board of Directors and a General Manager assisted by a Deputy General Manager. Its financing is provided by the state budget and fees collected from revenues generated from activities carried out by operators of the sectors concerned. ARSEL's decisions are highly influenced by the government via the Ministry of Power, the Prime Minister's Office and the General Secretariat of the Presidency of the Republic. The Ministry of Energy and Water is the Ministry mandated to issue specific regulations relating to the electricity sector and to issue the concessions, licenses and authorizations to be granted to the operators in the sector.

Principal Regulations. The principal legislative instrument governing the power sector is Law No. 2011/022 of December 14, 2011, which sets out a new institutional framework for the Power Sector and lays the foundation for competition in the power market in Cameroon. It is supplemented by the following instruments:

- Decree No. 2000/464/PM of June 30, 2000, governing the activities of the power sector;
- Decree No. 2001/021/PM of January 29, 2001, setting out the rates and methods of calculation, collection and distribution of the fees payable by operators involved in the power sector;
- Ministerial Order No. 061/CAB/MINMEE of January 30, 2001, setting out the documents and fees required in applying for concessions, licenses, authorizations and declarations for the generation, transmission, distribution, export and sale of power;
- Ministerial Order No. 000013/MINMEE of January 26, 2009, approving the regulation of the public distribution of electricity in Cameroon; and
- Concession Agreements and licenses agreements between the Republic of Cameroon and AES SONEL signed on July 18, 2001 and amended in 2006.

Material Regulatory Issues. A tariff compensation agreement between AES Sonel and the Republic of Cameroon was signed in November 2010. Abiding by the agreement, approximately $36 million of compensation was owed by the Republic of Cameroon to AES Sonel in December 2011 and an initial payment of approximately $11 million was paid at that time. Further payments are scheduled for the first quarter of 2012. Agreement with the Regulator on the tariff mechanism for 2012 was reached in December 2011. The tariff reset is expected to be finalized by the end of January 2012.

The new Electricity Law promulgated in December 2011 established a Transmission Network Organization in the form of a Public Liability Company. The law indicates that this organization's "missions, organization and functioning shall be laid down by decree of the President of the Republic." It is not yet clear when the Presidential Decree will be issued. It is also unclear whether the new entity will operate the system, or operate, maintain and develop the system. In either case, this entity could possibly take responsibility for transmission activity and management of the transmission grid away from AES SONEL. The impact on AES is not known at this time; however, it could be material to our results of operations.

Environmental Regulations. The principal environmental regulation is derived from Law No. 96/12 of August 5, 1996 and various implementing decrees and ministerial orders. This regulation applies to all sectors but there are some specific requirements relating to the electricity sector. The main requirement of this regulation for our subsidiaries in Cameroon is the obligation to conduct an environmental impact analysis for the planned construction of new generation installations, new transmission lines or substations.

Potential or Proposed Regulations. There are other generation projects whose regulatory specifications have yet to be clearly determined. The regulatory framework relating to the development of this new capacity and to the future contractual relationship between these new projects and AES SONEL is still unclear. However, the tariff compensation agreement referred to above provides that additional costs imposed on AES SONEL with regard to these projects shall be fully passed through in tariffs charged to end-users.

Chile

Structure of Electricity Market. In Chile, except for the small isolated systems of Aysén and Punta Arenas, generation activities are principally in two electric grids: the Central Interconnected Grid ("SIC"), which supplies approximately 92% of the country's population; and the Northern Interconnected Grid ("SING"), in which the principal users are mining and industrial companies. Power generation is based primarily on long-term contracts between generation companies and their customers specifying the volume, price and conditions for the sale of energy and capacity. The law recognizes two types of customers for generation companies: unregulated customers and regulated customers. Unregulated customers are principally consumers whose connected capacity is higher than 2 MW and consumers whose connected capacity is between 500 kW and 2 MW who have selected the unregulated pricing mechanism for a period of four years. These customers are not subject to price regulation and are able to freely negotiate prices and conditions for electricity supply with generation and distribution companies. Regulated customers are those whose connected capacity is less than or equal to 500 kW and those with connected capacity between 500 kW and 2 MW who have selected, also for four years, the regulated pricing system.

Electricity generation in each of the SIC and the SING is coordinated by the respective independent Economic Load Dispatch Center ("CDEC") in order to minimize operational costs and ensure the highest economic efficiency of the system, while fulfilling all quality of service and reliability requirements established by current regulations. In order to satisfy demand at the lowest possible cost at all times, each CDEC orders the dispatch of generation plants based strictly on variable generation costs, starting with the lowest variable cost, and does so independently of the contracts held by each generation company. Thus, while the generation companies are free to enter into supply contracts with their customers and are obligated to comply with such contracts, the energy needed to satisfy demand is always produced by the CDEC members whose variable production costs are lower than the system's marginal cost at the time of dispatch. For this reason, in each hour a given generator is either a net supplier to the system or a net buyer. Net buyers pay net suppliers for energy at the system's marginal cost. In addition, the Chilean market is designed to include payments for capacity (or firm capacity), which are explicitly paid to generation companies for contributing to the system's sufficiency. The cost of investment and operation of transmission systems is paid for by generation companies and consumers (regulated tolls) in proportion to their use.

Principal Regulators. The Chilean Ministry of Energy, created in 2010, grants concessions for the provision of the public service of electric distribution and the National Commission for the Environment administers the system for evaluating the environmental impact of projects. Thermoelectric plants do not require electrical concession agreements from the government in order to be built or to operate. The Ministry of Energy works with several agencies related to energy issues, such as the National Energy Commission ("NEC"), the Electricity and Fuels Superintendent, Energy Efficiency Agency and the Chilean Nuclear Commission, among others, in order to coordinate energy affairs. The NEC establishes, regulates and coordinates energy policy. The Superintendent of Electricity and Fuels oversees compliance with service quality and safety regulations. The General Water Authority issues the rights to use water for hydroelectric generation plants. The Chilean electrical system includes a Panel of Experts—an independent technical agency whose purpose is to analyze and resolve in a timely fashion conflicts arising between companies within the electric sector and among one or more of these companies and the energy regulators. In addition, the Ministry of Environment is responsible for the development and implementation of environmental regulations, protection of the environment, environmental education and pollution control, among others.

Principal Regulations. The distinct electricity sector activities are regulated by the General Electricity Services Law. Sector activities are also governed by the corresponding technical regulations and standards. The keystones of electricity regulation include: (i) the regulated compulsory marginal cost dispatch based on audited variable costs; (ii) the contract-based wholesale generation market; (iii) an open-access regime for transmission with benchmark regulation for existing transmission lines and auctions for new transmission facilities; (iv) benchmark regulation for the distribution grid; and (v) electricity retailing by distribution companies in their exclusive concession areas.

In accordance with the law, new contracts assigned by distribution companies for energy consumption must be awarded to generation companies based on the lowest supply price offered in public bid processes. These prices, called "long-term node prices," include indexation formulas and are valid for the entire term of the contract, up to a maximum of 15 years. More precisely, the long-term energy node price for a particular contract is the lowest energy price offered by the generation companies participating in each respective bid process, while the long-term capacity node price is that set in the node price decree in effect at the time of the bid.

In August 2011, President Sebástian Piñera's administration extended the energy decree that enables the government to take preventive measures to reduce the risk of future energy shortages in the SIC. At present, Chile is experiencing a significant drought that has diminished the country's reservoir levels and hydroelectric power capacity in the SIC. The decree will remain in force until April 2012 and includes three main actions: (i) diminishing available voltage by 10%-12.5%; (ii) saving reservoir capacity for up to 500 GWh; and (iii) offering incentives for consumers to save electricity. The decree is not expected to have a material impact on AES Gener's results.

Environmental Regulations. Law 20,257, enacted in April 2008, promotes nonconventional renewable energy sources, such as solar, wind, small hydroelectric and biomass energy sources. This law requires every electricity generator to supply a certain portion of its total contractual obligations to supply electricity with nonconventional renewable energy ("NCRE"). The required amount is determined based on contract agreements executed after August 31, 2007. The NCRE requirement is equal to 5% for the period from 2010 through 2014, and thereafter the required percentage increases by 0.5% each year, to a maximum of 10% by 2024. The obligation to supply a required percentage is currently required through 2034. Generation companies are able to meet this requirement by developing their own NCRE generation capacity (wind, solar, biomass, geothermal and small hydroelectric technology), or purchasing their NCRE supply from qualified generators, purchasing from other generators that generated NCREs in excess of their own requirements during the previous year or by paying the applicable fines for noncompliance.

Our businesses in Chile currently fulfill our NCRE requirements by utilizing our own biomass power plants and by purchasing NCREs generated by other generation companies. To date, we have sold certain water rights to companies that are developing small hydroelectric projects, entering into power purchase agreements with these companies in order to promote development of these projects, while at the same time meeting our own NCRE requirements.

On June 23, 2011, a new regulation on air emission standards for thermoelectric power plants became effective. This regulation provides for stringent limits on emission of particulate matter and gases produced by the combustion of solid and liquid fuels, particularly coal. For existing plants, including those currently under construction, the new limits for particulate matter emission will go into effect by the end of 2013 and the new limits for SO_2, NO_X and mercury emission will begin to apply in June 2015. In order to comply with the new emission standards, we estimate that AES Gener will have to invest approximately $280 million between 2012 and 2015, including its proportional investment in an equity-method investee, Guacolda. AES Gener is currently in the process of requesting equipment offers in order to determine the exact investment amounts and the timing of each investment.

Potential or Proposed Regulations. A proposed law that would provide new NCRE incentives is under discussion in the Congress. The proposed law increases the requirements of NCRE beginning 2015, such requirements reaching 20% as a percentage of customer demand in 2020. The new requirements would need to be fulfilled with NCRE coming from the same grid (the SIC or the SING) as the electricity it offsets. The NCRE would have to be accredited by the NEC, which may impose fines for noncompliance. The impact to AES Gener is under analysis; however, it will depend on the new size limit of small run-of-river hydroelectric units and if the new requirement is applied to existing power supply contracts, which only include the 10% NCRE component required by the current law. The proposed law, if passed, could result in increased costs or otherwise have a material impact on our results of operations.

In September 2010, the NEC proposed new Ancillary Services ("AS") standards designed to regulate AS transactions among generators for frequency regulation, spinning reserve, nonoperating reserve and automatic load shedding. AES Gener submitted comments on the proposed standards. AES Gener is assessing the potential impact of this regulation, although an estimate of the impact can only be established when the final regulation is issued. However, if passed, the regulations could result in required investments or other increased costs which could have a material and adverse impact on our results of operations.

In May 2011, the government created a Commission on Electric Power Development ("CADE"), formed by independent specialists in the sector. The administration requested that the CADE review the current problems in the electricity sector. This commission presented its final report in November 2011 with suggestions for distinct electric regulations including: energy policy and institutional framework, penetration of renewables, transmission system expansions, and competition in generation and generation planning. AES Gener expects the government to adopt certain proposals based on the CADE's recommendations.

Colombia

Structure of Electricity Market. Colombia has one main national interconnected system (the "SIN"). The wholesale market is organized around both bilateral contracts and a mandatory pool and spot market for all generation units larger than 20 MW.

In the spot market, each unit bids its availability and a set price for a 24-hour period. The dispatch is arranged from lowest to highest bid price and the spot price is set by the marginal price. There are two types of customers: unregulated customers and regulated customers. Unregulated customers are consumers whose maximum capacity consumption is higher than 0.1 MW, or whose energy demand is greater than 55 MWh/ month. These customers are not subject to price regulation; therefore, generators or trader companies are able to freely negotiate prices and conditions for electricity supply with them. Regulated customers have their prices determined by means of public tenders.

Electricity generation in the Colombian system is coordinated by the market administrator whose goal is to minimize operational costs while fulfilling all quality-of-service and reliability requirements established by current regulations. In order to satisfy demand at the lowest possible cost at all times, market administrator orders the dispatch of generation plants based on offer price (variable cost plus reliability charge) by merit, starting with the lowest offer price, and does so independent of the contracts held by each generation company. For this reason, in each hour a given generator is either a net supplier to the system or a net buyer. Net buyers pay net suppliers the system's spot price. In addition, the Colombian market is designed to include reliability payments, which are paid to generation companies for contributing to the system's sufficiency. The costs of investment and operation of transmission systems are borne by the consumers in proportion to their use.

Principal Regulators. The Ministry of Mines and Energy ("MME") establishes the energy policies and the Regulatory Commission of Electricity and Gas ("CREG") was created to foster the efficient supply of energy through regulation of the wholesale market, the natural monopolies of transmission, and distribution, and by setting limits for horizontal and vertical integration. The Ministry of the Environment ("MMA") establishes the environmental policies.

The Public Services Superintendence supervises the correct provision of utilities and the Industry and Commerce Superintendence is in charge of sanctioning any anticompetitive practice. Other entities that have an impact on the electric system include the Energy Planning Unit ("UPME"), in charge of planning the electricity and gas system, and the National Development Planning Office ("DNP"), whose main role is to develop a general development plan for the government.

Principal Regulations. The laws of Domiciliary Public Services and the Electricity Law set the institutional arrangement and the general regulatory framework for the electricity sector. The keystones of the electricity regulation are: (i) the dispatch is based on an offer price that represents the variable cost of the plants; (ii) a contract-based wholesale generation market; (iii) an open access regime for transmission with revenue regulated for existent transmission lines and open bids for new lines; (iv) revenue regulated for the distribution grid; and (v) electricity retail can be performed by distribution and/or traders.

The spot market started in July 1995, and in 1996 a capacity payment was introduced for a term of ten years. In December 2006, a regulation was enacted that replaced the capacity charge with the reliability charge and established two implementation periods. The first period consists of a transition period from December 2006 to November 2012 during which the price is equal to $13.045 per MWh and volume is determined based on each plant's firm energy which is prorated so that the total firm energy level does not exceed system demand. During the second period, which begins on December 2012, the reliability charge will be determined based on the energy price and the volume of offers submitted by market participants bidding for new capacity for the system. The first reliability charge auction was held in May 2008 with the following results: (i) the reliability charge for existing plants for the period between December 2012 and November 2013 will be $13.998 per MWh; (ii) for new plants that won the auction, the charge will be paid for twenty years starting December 2012; and (iii) three new projects won the auction for a total capacity of 430 MW starting in 2012. The new methodology established in 2006 recognized the reliability provide by Chivor's system and favored the company by increasing the reliability charge by approximately 120%, moving from $18 million in 2006 to almost $40 million in 2007 and is expected to remain at the same amount per year until 2015.

Environmental Regulations. In Colombia, Law 99 created the MMA (Ministry of the Environment) in 1993. This law requires projects that affect the land or impact the environment to obtain a license from the MMA. While regional environmental authorities can issue licenses for generation projects with capacity of less than

100 MW, only the MMA has the authority to issue licenses for the construction of large-scale generation or transmission projects with 100 MW capacity or greater. Chivor initiated operations in 1977 through a water concession, the only environmental requirement at that time. In August 1995, the MMA began requiring hydroelectric plants, including Chivor, to fulfill the requirements of an "Environmental Management Plan," which serves as an environmental operating permit. Each year, Chivor has to demonstrate to the environmental authorities that the obligations included in such plan are being fulfilled. Additionally, hydroelectric plants must contribute 6% of their gross generation and thermal plants 4% of their gross generation to the area of influence valued at a special tariff defined by CREG. In 2008, MMA issued Resolution 909 that regulates the emission of thermal power plants. This resolution is not expected to affect Chivor because it is a hydroelectric plant, but could affect AES if we decide to acquire or build a thermal plant in Colombia.

Potential or Proposed Regulations. CREG (Regulatory Commission of Electricity and Gas) issued a proposal to create the Organized Regulated Market ("MOR"). The MOR will replace the current bilateral contracts markets (between traders/utilities and generators) by putting in place a centralized auction in which the market administrator buys energy for all regulated customers served by the traders/utilities. The main provisions contained in the proposal are: (i) it is mandatory for all traders/utilities to buy energy at the auction price and it is voluntary for sellers (generators and trade companies) to offer energy in each auction; (ii) there is one single price for the energy sales in the auction; (iii) the auctions are held one year before the actual dispatch and the commitment period of the auction is one year; and (iv) four auctions are to be established per year. Bilateral contracts executed before the beginning of the MOR's operation will not suffer any change and will remain valid. A definitive resolution will be issued in the first half of 2011.

During 2010, MME (Ministry of Mines and Energy) issued Decree 2730 which intends to solve the potential long-term and/or cyclical unavailability of gas by (i) importing LNG and (ii) establishing strategic storage alternatives. Also, the government presented the basis for the "National Development Plan 2011–2014." For the electricity sector, the plan mainly focuses on: (i) maintaining stability of the current regulatory framework, supporting the current reliability charge structure, promoting fair competition among technologies and guaranteeing no new taxes to transactions made in the wholesale market; (ii) assuring energy supply for the medium and long term; (iii) enhancing and strengthening the electricity market's competitiveness in order to maintain investment confidence and convert the electricity system in Colombia into a world class sector; (iv) making the right decisions in the natural gas sector to make it reliable; and (v) promoting institutional improvement guided by transparency, independence and efficiency. Among these initiatives, they are considering reviewing the separation of National Dispatch Center from the Commercial Transactions Administrator and self-regulation initiatives to avoid or minimize interventions in the market by the government. These initiatives also seek to resolve the gas supply problem for thermal plants. Furthermore, the National Development Plan proposal aims to maintain the stability and certainty of the market rules in order to consolidate the investor trust.

As a part of CREG regulatory agenda for 2011, the regulator is planning to review the lessons learned from the dry conditions brought by the 2009-10 "El Niño" phenomenon and issue regulations for these extreme events, permitting players to know in advance the additional reliability measures that the regulator may take under those circumstances. Also, CREG is planning to issue regulations that will strengthen the energy market by improving the spot market guarantees plan, and establish measures to control market power from pivotal agents (agents needed at any cost to fulfill the demand requirements). This last initiative may affect spot prices which could impact our sales not covered by contracts.

Dominican Republic

Structure of Electricity Market. The Dominican Republic has one main interconnected system with approximately 3,000 MW of installed capacity, composed primarily of thermal generation (85%) and hydroelectric power plants. AES Dominicana has 28% share of this capacity (849 MW) and supplies approximately 40% of energy demand through 3 power generators. The regulatory framework in the Dominican Republic consists of: decentralized industry; unbundled generation, transmission and distribution; regulated prices in monopolistic segments (transmission and distribution); and a competitive wholesale generation market. In accordance with this regulatory structure, all agents and electric generation, transmission and distribution companies must conduct their operations to provide the best service at minimum cost and comply with standards of quality, safety, continuity of services and conservation of the environment.

The wholesale market is composed of the long-term Power Purchase Agreements and the spot market. The wholesale market is based on a marginal market divided in capacity, energy and ancillaries services (frequency regulation, compensation, and reactive power).

The energy market is based on a centralized economic dispatch. The Organismo Coordinador ("OC") is in charge of planning and supervision of operations through the "Centro del Control del SENI," which is in charge of real-time dispatch. The dispatch of the thermal units is based on auditable declared variable costs and, for the hydroelectric units, the variable cost is equal to zero, meaning that these units are the first for dispatch and reflect optimal system costs. The spot market relies on competitive bidding based on each generator's variable costs as a means of providing a merit order for dispatch. Variable cost information is submitted weekly by the generators to the OC, which then determines the merit order for dispatch based on this information.

The capacity market is based on the availability of a power plant to cover the maximum demand during the year with a price that financially covers the fixed cost of a 50 MW gas turbine generation installed in Dominican Republic with a 10% of reserve.

For the sale of electricity under long-term contracts, the regulatory framework establishes that the sale of electricity of a generating company to a distribution company will be done at prices resulting from the competitive procedures of public bidding. These bids are governed by the conditions established by the Superintendency of Electricity ("SIE") which supervises the bidding and awarding process. With the objective of ensuring that generation prices represent reasonable values in the market, the SIE ensures that the sale of electricity through contracts is not greater than 80% of interconnected electric energy demand, and that the spot market represents a minimum of 20% of the total national consumption of the interconnected system annually. AES Dominicana has 90% of its capacity under long term contracts and is the main generator that provides frequency regulation services.

The electricity tariff applicable to regulated customers is subject to regulation within the concessions of the distribution companies. Electricity end-users are considered customers of public services according to regulations, hence the tariff is set by resolution of the SIE. For clients with demand above 1.2 MW who are classified as unregulated customers, tariffs are unregulated.

Principal Regulators. In order to regulate the electric sector and implement the provisions contained in the General Electricity Law No. 125-01 and its by-law, two regulators are responsible for monitoring and ensuring compliance with the law: the National Energy Commission ("CNE") and the SIE. All electric companies (generators, transmission and distributors), are subject to and regulated by the General Electricity Law, whether they are of national and/or foreign capital, private and/or public.

In general, CNE's main responsibilities are to draft and coordinate the legal framework and regulatory legislation; propose and adopt policies and procedures to assure best practices; draft plans to ensure the proper functioning and development of the energy sector and propose them to the Executive Branch; ensure compliance with the law; promote investment decisions in accordance with these plans; and advise the Executive Branch on all matters related to the energy sector. The SIE's main responsibilities are to develop, ensure compliance with and analyze the structure and level of prices of electricity and to set the rates and tolls subject to regulation. SIE also reviews electricity rate levels requested by companies, monitors and supervises compliance with legal provisions and rules and monitors compliance with the technical procedures governing generation, transmission, distribution and commercialization of electricity. In addition, SIE supervises electric market behavior in order to avoid monopolistic practices and applies penalties and fines in the cases of noncompliance with the laws and regulations.

Principal Regulations. The energy sector regulatory framework in the Dominican Republic is governed primarily by:

- General Electricity Law 125-01, its by-law and its amendment by Law 186-07 constitute the legal framework that regulates all phases related to the production, transmission, distribution and commercialization of electricity, as well as the functions of state agencies created by this law and related to these matters. The regulatory framework in the Dominican electricity market establishes a methodology for calculating the firm capacity for each power generation unit.
- Renewable Energy Incentives Law 57-07 establishes incentives for renewable energy, mainly income tax exemption, import taxes reduction, as well as special operational, technical and commercial treatment. The law applies to hydroelectric generation with a capacity equal to or below 5 MW, wind generation with a capacity less than 50 MW, biomass generation with a capacity less than 80 MW, photovoltaic generation, and thermo-solar generation with a capacity less than 120 MW.
- Hydrocarbons Law 112-00 establishes a tax on consumption of fossil fuels. All fossil fuels including natural gas used to produce electricity have a tax exemption under the law and any change in this regulation does not affect AES Dominicana as a natural gas provider. All agents that use any fossil fuel to produce electricity must file a request to the CNE and the Industry and Commerce Ministry to apply for this exemption.
- Industry and Commerce Ministry periodic resolutions for technical and price regulations for vehicular natural gas use (transportation).

In addition, the Dominican government has directly exercised varying degrees of regulation over the electricity market and AES Dominicana's businesses in the past, such as involvement in the renegotiation of the existing PPAs, oversight responsibilities of the SENI and environmental controls. No assurance can be given that the Dominican government will not alter regulations in the future in a way that will negatively affect AES Dominicana's businesses, financial conditions or results of operations.

Environmental Regulations. The main environmental regulations are the General Law on Environment and Natural Resources 64-00 and the Regulation and Licensing Systems Environmental Permits by-law. These regulations provide for centralized environmental planning by the state through the integration of environmental protection and economic development plans in a common approach and policy throughout the sector. Environmental regulation takes the form of permits or environmental licenses, environmental quality standards and environmental reporting. The main regulatory institutions are:

- The Ministry for the Environment and Natural Resources, which is responsible for implementing and designing the policy for the conservation and protection of the environment and natural resources in the Dominican Republic;
- National Council of Environment and Natural Resources, which is the link between the various Ministries of State in charge of evaluating the impact of environmental policies; and
- Deputy Attorney General for the Defense of the Environment and Natural Resources, which is responsible for performing the actions by the State Environmental conflicts environment.

Despite extensive compliance plans in place by each of the entities, it is possible AES Dominicana generating units could fall out of compliance with such environmental standards. Such non-compliance, and resulting penalties or bad publicity might negatively affect the financial results of AES Dominicana. One such penalty could be a requirement that AES Dominicana operates its offending unit below its rated capacity, and such unavailability might affect compliance with obligations under its PPAs. In such a scenario, AES Dominicana might need to make significant investments in environmental-related infrastructure. In addition, the environmental laws and regulations may become more stringent and AES Dominicana might be forced to make certain investments to be compliant with the new standards.

Potential or Proposed Regulations. During the last quarter of 2011 the regulatory agencies, CNE, SIE and OC set up a task force to review some elements of current regulations. The three regulatory proposals being discussed would: (1) modify the spot price cap with a 5% increase; (2) provide compensation to generation companies in situations where variable costs exceed the spot price (making production of electricity uneconomical) to help meet demand and ensure energy security; and (3) modify the regulations related to frequency regulation, under which (a) generators may have to contribute a percentage of available power as frequency margin which may or may not be paid and plants unable to provide the margin will be required to purchase it or (b) higher variable cost units will provide the margin with compensation.

El Salvador

Structure of Electricity Market. The Salvadorean electricity market is composed of a single interconnected system. Under the General Electricity Law ("GEL"), competition was introduced in generation and trading; additional regulations were implemented related to price and quality of service in non-competitive segments such as distribution, transmission, system operation and administration.

The wholesale electricity market is based on a contract market and a spot market. The contract market is further classified into bilateral contracts, which are freely negotiated by electricity generators, distributors, and trading companies, and regulated contracts, which are the product of regulated public bids carried out by the distribution companies under the supervision of the Regulator, Superintendencia General de Electricidad y Telecomunicaciones ("SIGET"). The Spot Market operates on the basis of bids and prices corresponding to increases or decreases of the quantities of electricity established in a scheduled dispatch.

Starting in February 2012, the distribution companies are required to acquire 70% of their forecasted demand through regulated bids. The spot market is structured as a day-ahead market, and transactions are settled on a monthly basis. The Transmission System and Wholesale Market Operating Rules have been amended to convert the wholesale market price-setting mechanism from a competitive bidding process into audited variable production costs and the amendments became effective on August 1, 2011.

Distribution companies are regulated under an incentive system, specifically a Revenue Cap system, whereby the maximum tariff to be charged to the end-users is subject to the approval of SIGET. The components of the electricity tariff are (i) charges for the use of the distribution network (the "Distribution Charge"), (ii) customer service costs (the "Service Charge") and (iii) average energy price (the "Energy Charge"). Both the Distribution Charge and Service Charge are based on average capital costs as well as operation and maintenance costs of an efficient distribution company. The Distribution Charge and Service Charge are approved by SIGET every five years and have two adjustments: (i) an annual adjustment considering the inflation variation and (ii) an automatic adjustment in April, July and October, provided that the change in inflation is greater than 10%.

Competition is encouraged by the GEL and it provides the end user with the option to acquire its electricity from a distribution company or an electricity trader. The distribution and transmission companies are mandated by the GEL to allow the use of the distribution grid to traders in order to deliver electricity to their customers. The grid access terms, including tariffs, are detailed in a "distribution contract" registered and regulated by SIGET.

Principal Regulators. SIGET is the independent regulatory authority established through the GEL. SIGET's principal responsibilities and attributions are the approval of Distribution Value Added Charges ("DVA"), enforcement of sector regulation, dispute resolution among market participants, granting concessions for hydroelectric and geothermal projects, among others.

In addition, the National Energy Council (Consejo Nacional de Energia or CNE), formed in 2007, is the policy-making entity, whose board of directors is composed of the Secretaries of Treasury, Economy, Public Works, Environmental and Natural Resources and the Consumer Protection Agency.

Principal Regulations. The electricity sector is governed by the General Electricity Act, the General Electricity Act Regulations, the Transmission System & Wholesale Market Operating Regulations and the general and specific orders issued by SIGET, under its statutory attributions.

Environmental Regulations. The Environment and Natural Resources Act ("ENRA"), enacted in 1998, and the regulation promulgated therein, enacted in 2000, set forth environmental requirements in El Salvador. These statutes empower the Environment and Natural Resources Secretary to set environmental policy, and ENRA establishes a duty of care to the environment and orders the sustainable use of natural resources. Additionally, ENRA sets forth environmental permitting requirements for the handling of certain potentially hazardous or risky materials or performing certain activities in the environment, such as the construction and operation of power plants (except fuel oil) and transmission lines.

Material Regulatory Actions. The Energy Charge has been, under current methodology, adjusted every six months to reflect the spot market price for electricity during the previous six months. However, starting on January 12, 2011, the energy charge has been adjusted quarterly. Presidential Decree 160 was published on December 23, 2010 and went into effect on January 1, 2011. This decree shortens the Energy Charge reset period from six months to three months; the new Energy Charge reset dates will be January 12th, April 12th, July 12th and October 12th each year. The reduction of the Energy Charge reset period reduces the distribution companies' cash flow exposure before any significant spike in energy prices since the lag between energy revenues and costs has been reduced by half.

Potential or Proposed Regulations. The Regulator, jointly with the Distribution Companies of El Salvador (AES El Salvador and Del Sur) are in the process of reviewing and changing the methodology of the tariffs calculation, and this process will take place during the first quarter of 2012. The outcome of the new methodology will be used to calculate the new tariffs to be applied for the period from 2013 to 2017.

Currently the calculation of the distribution and commercialization charges are carried out by the evaluation/ comparison against a model company, which will be replaced by the utilization of a real company (using actual costs instead of modeled costs). The impact of a change in methodology is not known, but it could be material.

Nigeria

Structure of Electricity Market. In Nigeria, the state-owned entity, Power Holding Company of Nigeria ("PHCN"), holds approximately 80% of the electricity market share. Private power generating companies account for the remaining 20%. The private power generating companies, one of which is AES Nigeria Barge Ltd. ("AESNB"), maintain long-term contracts with PHCN, the sole off taker.

All power transmission operations are currently carried out by PHCN. Under new political initiatives and reforms, as provided under the Roadmap for Power Sector Reforms ("the Power Roadmap"), there are indications that 11 distribution companies and six generation companies would be fully privatized while the Transmission Company of Nigeria ("TCN") would continue to be owned by the government, but managed by the private sector. Currently, all electricity generation is from either gas-fired or hydro power plants. Most assets are owned by state-owned companies, though some private investors have been able to establish IPPs following recent reforms. In addition, the government is developing approximately 4,800 MW of installed capacity intended to be completed by 2013, known as the National Integrated Power Plants ("NIPPs"). The Presidential Task Force on Power has announced its intention to privatize the NIPPs in future rounds of privatization, following completion of construction.

Principal Regulators. The Nigerian Electricity Regulatory Commission ("NERC") is an independent regulatory agency that was established under the 2005 Reform Act to undertake both the technical and economic regulation of the Nigerian electricity sector. It is responsible for general oversight functions, including the licensing of operators, setting of tariffs and establishing industry standards for future electricity sector development.

Two of the NERC's key regulatory functions are licensing and tariff regulation. Since AESNB operates under a long-term bilateral agreement with PHCN, it is not subject to the tariff setting process. On the basis of the current reforms embodied in the Power Roadmap, a number of new regulatory and/or other governing bodies will be established to regulate the industry.

Principal Regulations. In March 2005, the Nigerian President signed the Electric Power Sector Reform Bill into law, enabling private companies to participate in transmission and distribution, in addition to electricity generation that had previously been legalized. The government has since separated PHCN into eleven distribution firms, six generating companies, and a transmission company, in preparation for privatization.

Several events, including union opposition, have delayed the privatization indefinitely; however, the current government has put significant emphasis on completing the privatization of the eighteen successor companies of the PHCN in 2012. There are clauses in the AESNB PPA that, upon the effective date of a privatization, require the business to use all reasonable endeavors to obtain and acquire all fuel necessary for the operation of the plant. Additionally, the off-taker will be transferred from PHCN to Lagos State as also stated in the PPA. However, the government has recently set up the Nigerian Bulk Electricity Trader ("NBET"), an entity that is intended to be the off-taker between the generation and distribution companies backed by World Bank Partial Risk Guarantees ("PRGs"). The NEBT is expected to take over the off taker function from PHCN once it becomes fully privatized. No material impact to our operations is expected at this time because of this reform.

The 2005 Reform Act and NERC regulations provides for a generation license to have duration of 10 years, renewable for a further five years. This is in line with a current proposal for a uniform tariff for the power sector, MYTO, which is derived from a building blocks approach that anticipates a cost-reflective outcome, including a capacity and an energy component; financing costs and other key costs (operating costs, depreciation) and key fluctuating costs (fuel costs, foreign exchange, inflation). A total license and uniform tariff duration of 15 years may present challenges to potential investors given that 15 years may be shorter than the useful life of assets and shorter than the tenor of potential long-term debt financing. A new proposal to increase the license duration to 20 years has been proposed, but this issue has not been resolved. Potential inadequate gas supply and transmission constraints, which may pose a risk to continuous generation in the numerous proposed gas generation plants, may be viewed as additional risks by investors.

Panama

Structure of Electricity Market. In Panama, distribution companies are required to contract 100% of their annual power requirements (although they can self-generate up to 15% of their demand). Generators can enter into long-term PPAs with distributors or unregulated consumers. In addition, generators can enter into alternative supply contracts with each other. The terms and contents of PPAs are determined through a competitive bidding process and are governed by the Commercial Rules. Besides the PPA market, generators may buy and sell energy in the spot market. Energy sold in the spot market corresponds to the hourly differences between the actual dispatch of energy by each generator and its contractual commitments to supply energy. The energy spot price is set by the order in which generators are dispatched. The National Dispatch Center ("CND") ranks generators according to their variable cost (thermal) and water value (hydroelectric), starting with the lowest value, thereby establishing on an hourly basis the merit order in which generators will be dispatched the following day in order to meet expected demand. Concessions granted to distribution companies (15 years and 51% of ownership) will end in October 2013; the regulator will call for a bidding process to sell the majority of the shares of the three distribution companies. It is expected for the three current holders of the share packages: *Empresas Publicas de Medellin* (Colombia) shareholder in ENSA and *Gas Natural Fenosa* (Spain) shareholder in EDEMET and EDECHI to participate. The law provides that if a current shareholder offers no less than the highest price offered by any other participants it will retain ownership of the shares.

Principal Regulators. The National Secretary of Energy ("SNE") was created by Law 52 on July 30, 2008 and reorganized by Law 43 of April 2011 (in which SNE became a Ministry); and has the responsibilities of planning, investigating, directing, supervising and controlling policies of the energy sector within Panama. With these responsibilities, the Secretariat has defined strategies and policies for the Republic of Panama, which include promoting energy security for the benefit of the population and the country's development, and proposing laws and regulations to the executive agency that promote the procurement of electrical energy, hydrocarbons and alternative energy in the best conditions for the country.

The regulator of public services, known as the National Authority of Public Services ("ASEP"), was created by Law 26 on January 29, 1996. ASEP is an autonomous agency of the government, with legal responsibility and self-patrimony. ASEP is responsible for the control and oversight of public services, such as potable water, sewerage, electricity, telecommunications and radio and television systems, as well as the transmission and distribution of natural gas utilities and the companies that provide such services. ASEP's mission is to ensure the efficient provision of the public services, as well as national, technical, commercial, and environmental quality standards.

Principal Regulations. In the Republic of Panama, the electricity sector is regulated by Law No. 6 issued in February 1997 which was subsequently amended several times. The most recent amendment was Law 58 on May 30, 2011. Some notable amendments by Law 58 were: (i) creation of the Rural Electrification Fund, which will be administered by the government to provide service to rural and poor areas of the country; and (ii) obligation of all market participants to contribute up to 1% of their net income before income tax to the Fund. A compilation of Law 6, including all amendments, was issued on September 14, 2011.

Environmental Regulations. ASEP issued Resolution AN No. 3932-Elec on October 22, 2010 related to the security of dams in the electricity sector. The Law became effective on November 9, 2011 but provided for a two month grace period for compliance. This legislation set a number of protocols for modifications of the dam structure, dam operations and reservoirs monitoring during floods, among others. In order to comply with such regulations, our subsidiaries in Panama have conducted an internal review of emergency procedures during flood events and reviewed dam safety requirements, processes and procedures. These requirements, processes and procedures have been submitted to external consultants in order to verify full compliance with the regulations and to advise and update any of our processes and procedures as necessary.

Material Regulatory Actions. By virtue of Resolutions No. 4493 and 4494 of June 7, 2011 ASEP cancelled the Concession Rights for the CHAN 140 project and administratively terminated the CHAN 220 Concession (both Concessions were to become the Changuinola II Project). AES subsidiaries filed two reconsideration actions before the regulator but both were denied. Following the judicial alternatives provided by the Panamanian legal framework, our subsidiaries filed actions for the protection of constitutional guarantees and claims before the Third Chamber of the Supreme Court against both resolutions.

ASEP has started a sanctioning process against certain of our subsidiaries in Panama due to the late payment of the market settlement for the month of August 2011. AES paid the settlement on October 20, 2011 (approximately 15 days late) once it received the over cost payment (due to the previously disclosed Esti tunnel collapse) from the government. The regulator has the legal capacity to issue fines up to $20 million.

Potential or Proposed Regulations. ASEP has made a proposal to modify the regulatory criteria for the design of bids for Financial Rights of Access to Interconnection Capacity ("DFACI") between Panama and Colombia, which were approved by Resolution 4507 of June 2011. This proposal includes restrictions on generators' ability to acquire DFACI if their capability to generate exceeds the maximum percentage of electric consumption that the local laws allow them to provide, which could adversely affect our ability to bid for interconnection capacity in the market.

North America

Mexico

Structure of Electricity Market. Mexico has a single national electricity grid (referred to as the "National Interconnected System"), covering nearly all of Mexico's territory. The only exception is the Baja California peninsula which has its own separate electricity system. Article 27 of the Mexican Constitution reserves the generation, transmission, transformation, distribution and supply of electric power exclusively to the Mexican State for the purpose of providing a "public service."

Since 1995 the power sector legal framework partially opened to private entities under the following schemes: cogeneration; self supply; IPP exports; and imports for self consumption. Private investments are allowed today in the sectors: transport, storage, and distribution. The Energy Regulatory Commission ("CRE") is in charge of issuing the permits related to the activities from the power and natural gas sectors that were open to private investment since 1995.

Principal Regulators. The Federal Electricity Commission ("CFE"), by virtue of Article 1 of the Energy Law, is granted sole and exclusive responsibility for providing this public service as it relates to the supply, transmission and distribution of electric power.

Principal Regulations. In 1992, the Energy Law was amended to allow private parties to invest in certain activities in Mexico's electrical power market, under the assumption that "self-supply" generation of electric power is not considered a public service. These reforms allowed private parties to obtain permits from the Ministry of Energy for (i) generating power for self-supply; (ii) generating power through co-generation processes; (iii) generating power through independent production; (iv) small-scale production; and (v) importing and exporting electrical power. Beneficiaries holding any of the permits contemplated under the Energy Law are required to enter into PPAs with the CFE with regard to all surplus power produced. It is under this basis that AES' Mérida and TEG/TEP facilities operate. Mérida provides power exclusively to CFE under a long-term contract. TEG/TEP provides the majority of its output to two offtakers under long-term contracts, and can sell any excess or surplus energy produced to CFE at a predetermined day-ahead price.

Environmental Impact. Projects or activities that may disrupt the ecological balance or exceed the limits and conditions established in the applicable laws or the regulations are subject to the conditions established by regulatory authorities to minimize the negative effects on the environment. Our businesses in Mexico must obtain authorization for matters with environmental impacts from the regulatory authorities.

High risk activities are also regulated, even though there is no specific definition for "high risk." The Mexican Department of the Interior issued two lists defining high risk substances. The criteria used to determine whether an activity is of high risk is based on the characteristics or volume of the substance used. If, in the event of a spill or release of a substance, it is possible to cause an explosion or significantly affect the environment, people or property, such substance will be considered "high risk." Further, if a project contemplates the use of a compound included in the lists issued by the regulator, in the necessary volumes, the responsible party must present a risk evaluation before the regulator.

Environmental Sanctions. The Attorney General's Office for the Protection of the Environment is in charge of enforcing environmental legal provisions in Mexico. The sanctions depend on the environmental obligations violated by individuals or corporations, and vary from fines that range from 50 to 50,000 days of minimum wage pay. Additional sanctions may also be imposed, including the annulment of environmental permits and authorizations, partial or total closures of a facility, and administrative arrest.

Mexican Legislation provides that the energy sector is integrated by the electrical and petroleum sectors. Federation is the only one entitled to extract and process fossil fuels, as well as to generate electricity; however, certain exceptions apply.

Renewable Energy. On October 25, 2008, the Renewable Energies and Financing of the Energy Transition Law was approved by the Energy Committee of the Mexican House of Representatives. The law encourages generation and transportation of energy generated by renewable sources, giving certainty and lower costs to provide incentives to participate in the private sector of this field.

In addition, the Federal government's broad Special Program on Climate Change ("SPECC") was formally approved. The SPECC provides a program to reduce the effects of climate change. The principal actions proposed to achieve competitive levels, include the gradual substitution of oil for natural gas, stimulating the implementation of cogeneration and other efficiency saving technologies and strongly stimulating the development of renewable energies.

Priority will be given to electricity generation from wind (up to 507 MW installed by 2012), geothermal energy (up to 153 MW installed by 2012), hydroelectric and solar power. The SPECC proposes a joint program between public bodies and private investors in order to increase the amount of electricity generation capacity from renewable sources up to 1,957 MW by 2012.

The SPECC makes it clear that many of its objectives will be achieved through the following normative, economic and market instruments: accessible financing mechanisms; simplification procedures for permitting; facilitation of electrical grid interconnection and transmission contracts; and stimulus for private investment in energy infrastructure. Our businesses in Mexico are still reviewing the impact of these developments on their operations; however, they could be material to the business and results of operations.

United States

Structure of Electricity Market. The United States wholesale electricity market consists of multiple distinct regional markets that are subject to both federal regulation, as implemented by the U.S. Federal Energy Regulatory Commission ("FERC"), and regional regulation as defined by rules designed and implemented by the Regional Transmission Organizations ("RTOs"), non-profit corporations that operate the regional transmission grid and maintain organized markets for electricity. These rules for the most part govern such items as the determination of the market mechanism for setting the system marginal price for energy and the establishment of guidelines and incentives for the addition of new capacity. The current regulatory framework in the United States is the result of a series of regulatory actions that have taken place over the past several decades, as well as numerous policies adopted by both the federal government and the individual states that encourage competition in wholesale and retail electricity markets.

Principal Regulators. The federal government, through regulations promulgated by FERC, has primary jurisdiction over wholesale electricity markets and transmission services. While there have been numerous federal statutes enacted during the past 34 years, including the Public Utility Regulatory Policy Act of 1978 ("PURPA"), the Energy Policy Act of 1992 ("EPAct 1992") and the Energy Policy Act of 2005 ("EPAct 2005"), there are two fundamental regulatory initiatives implemented by FERC during that time frame that directly impact our United States businesses:

- FERC approval of market-based rate authority beginning in 1986 for many providers of wholesale generation; and
- FERC issuance of Order #888 in 1996 mandating the functional separation of generation and transmission operations and requiring utilities to provide open access to their transmission systems.

FERC has civil penalty authority over violations of any provision of Part II of the Federal Power Act ("FPA") which concerns wholesale generation or transmission, as well as any rule or order issued thereunder. FERC is authorized to assess a maximum civil penalty of $1 million per violation for each day that the violation continues. The FPA also provides for the assessment of criminal fines and imprisonment for violations under Part II of the FPA. This penalty authority was enhanced in EPAct 2005. With this expanded enforcement authority, violations of the FPA and FERC's regulations could potentially have more serious consequences than in the past.

Pursuant to EPAct 2005, the North America Reliability Corporation ("NERC") has been certified by FERC as the Electric Reliability Organization ("ERO") to develop mandatory and enforceable electric system reliability standards applicable throughout the United States to improve the overall reliability of the electric grid. These standards are subject to FERC review and approval. Once approved, the reliability standards may be enforced by FERC independently, or, alternatively, by the ERO and regional reliability organizations with responsibility for auditing, investigating and otherwise ensuring compliance with reliability standards, subject to FERC oversight. Monetary penalties of up to $1 million per day per violation may be assessed for violations of the reliability standards.

Principal Regulations for Generation Businesses. Several of our generation businesses in the United States currently operate as Qualifying Facilities ("QFs") as defined under PURPA. These businesses entered into long-term contracts with electric utilities that had a mandatory obligation at that time, as specified under PURPA, to purchase power from QFs at the utility's avoided cost (i.e., the likely costs for both energy and capital investment that would have been incurred by the purchasing utility if that utility had to provide its own generating capacity or purchase it from another source). EPAct 2005 later amended PURPA to provide for the elimination of the mandatory purchase obligation in certain markets, but did so only on a prospective basis. Cogeneration facilities and small power production facilities that meet certain criteria can be QFs. To be a QF, a cogeneration facility must produce electricity and useful thermal energy for an industrial or commercial process or heating or cooling applications in certain proportions to the facility's total energy output, and must meet certain efficiency standards. To be a QF, a small power production facility must generally use a renewable resource as its energy input and meet certain size criteria.

Our non-QF generation businesses in the United States currently operate as Exempt Wholesale Generators ("EWGs") as defined under EPAct 1992. These businesses were historically exempt from the Public Utility Holding Company Act of 1935 and are also exempt from the Public Utility Holding Company Act of 2005 ("PUHCA 2005"), and, subject to FERC approval, have the right as public utilities under the FPA to sell power at market-based rates, either directly to the wholesale market or to a third-party offtaker such as a power marketer or utility/industrial customer. Under the FPA and FERC's regulations, approval from FERC to sell wholesale power at market-based rates is generally dependent upon a showing to FERC that the seller lacks market power in generation and transmission, that the seller and its affiliates cannot erect other barriers to market entry and that there is no opportunity for abusive transactions involving regulated affiliates of the seller. To prevent market manipulation, FERC requires sellers with market-based rate authority to file certain reports, including a triennial updated market power analysis for markets in which they control certain threshold amounts of generation. As part of the acquisition through merger completed in 2011 with DPL Inc., the Company slightly expanded the number of EWGs that it operates. One of DPL Inc.'s subsidiaries was DPL Energy, LLC, which owns about 584 MW of natural gas fired generation located at two sites, one in Ohio and the other in Indiana.

Principal Regulations for Traditional Utility Business. In addition to our generation businesses, we also own IPL, a vertically integrated utility located in Indiana and DP&L, a vertically integrated utility located in Ohio.

A description of the regulatory environment under which each operates is provided below:

Indianapolis Power & Light Company ("IPL")

As a regulated electric utility, IPL is subject to regulation by the FERC and the Indiana Utility Regulatory Commission ("IURC"). As indicated below, the financial performance of IPL is directly impacted by the outcome of various regulatory proceedings before the IURC and FERC.

IPL is subject to regulation by the IURC with respect to the following: its services and facilities; the valuation of property; the construction, purchase or lease of electric generating facilities; the classification of accounts; rates of depreciation; retail rates and charges; the issuance of securities (other than evidences of indebtedness payable less than twelve months after the date of issue); the acquisition and sale of some public utility properties or securities; and certain other matters.

IPL's tariff rates for electric service to retail customers (basic rates and charges) are set and approved by the IURC after public hearings ("general rate cases"). General rate cases, which have occurred at irregular intervals, involve IPL, consumer advocacy groups, and other interested stakeholders. The last general rate case for IPL was completed in 1995. In addition, pursuant to statute, the IURC is to conduct a periodic review of the basic rates and charges of all Indiana utilities at least once every four years, but the IURC has the authority to review the rates of any Indiana utility at any time it chooses. Such reviews have not been subject to public hearings.

The majority of IPL customers are served pursuant to retail tariffs that provide for the monthly billing or crediting to customers of increases or decreases, respectively, in the actual costs of fuel (including purchased power costs) consumed from estimated fuel costs embedded in basic rates, subject to certain restrictions on the level of operating income. These billing or crediting mechanisms are referred to as "trackers." This is significant because fuel and purchased power costs represent a large and volatile portion of IPL's total costs. In addition, IPL's rate authority provides for a return on IPL's investment and recovery of the depreciation and operation and maintenance expenses associated with certain IURC-approved environmental investments. The trackers allow IPL to recover the cost of qualifying investments, including a return on investment, without the need for a general rate case.

IPL may apply to the IURC for a change in its fuel charge every three months to recover its estimated fuel costs, including the energy portion of purchased power costs, which may be above or below the levels included in its basic rates and charges. IPL must present evidence in each fuel adjustment charge ("FAC") proceeding that it has made every reasonable effort to acquire fuel and generate or purchase power, or both, so as to provide electricity to its retail customers at the lowest cost reasonably possible.

Independent of the IURC's ability to review basic rates and charges, Indiana law requires electric utilities under the jurisdiction of the IURC to meet operating expense and income test requirements as a condition for approval of requested changes in the FAC. Additionally, customer refunds may result if IPL's rolling twelve-month operating income, determined at quarterly measurement dates, exceeds IPL's authorized annual jurisdictional net operating income and there are no sufficient applicable cumulative net operating income deficiencies against which the excess rolling twelve-month jurisdictional net operating income can be offset.

In IPL's fourteen most recently approved FAC filings (FAC 81 through 94), the IURC found that IPL's rolling annual jurisdictional retail electric net operating income was lower than the authorized annual jurisdictional net operating income. FAC 94 includes the twelve months ended October 31, 2011. In IPL's FAC 76 through 80 filings, the IURC found that IPL's rolling annual jurisdictional retail electric net operating income was greater than the authorized annual jurisdictional net operating income. Because IPL has a cumulative net operating income deficiency, IPL has not been required to make customer refunds in its FAC proceedings. However, IPL has previously offered voluntary credits to its customers to allay concerns raised by the IURC regarding IPL's level of earnings.

IPL may apply to the IURC for approval of a rate adjustment known as the Environmental Compliance Cost Recovery Adjustment ("ECCRA") every six months to recover costs to install and/or upgrade Clean Coal Technology ("CCT") equipment. The total amount of IPL's CCT equipment approved for ECCRA recovery as of December 31, 2011 was $615 million. The jurisdictional revenue requirement that was approved by the IURC to be included in IPL's rates for the six month period from September 2011 through February 2012 was $49 million.

In February 2009, an IPL customer filed a complaint claiming IPL's tree trimming practices were unreasonable and expressed concerns with language contained in IPL's tariff that addressed IPL's tree trimming and tree removal rights. Subsequently, the IURC initiated a generic investigation into electric utility tree trimming practices and tariffs in Indiana. In November 2010, the IURC issued an order in the investigation, which imposed additional requirements on the conduct of tree trimming. The order included requirements on utilities to provide advance customer notice and obtain customer consent or additional easements if existing easements and rights of way are insufficient to permit pruning in accordance with the required industry standards or in the event that a tree would need to have more than 25% of its canopy removed. The order also directed that a rulemaking would be initiated to further address vegetation management practices.

On July 7, 2011, the IURC issued an additional tree trimming order which did not provide the relief IPL was seeking, but clarified utility customer notice requirements and the relationship of the order to property rights and tariff requirements. It also clarified that in cases of emergency or public safety, utilities may, without customer consent, remove more than 25% of a tree or trim beyond existing easement or right of way boundaries to remedy the situation. The IURC is currently in the process of promulgating formal rules to implement the order. IPL and other interested parties are participating in this rulemaking process. It is not possible to predict the outcome of the rulemaking process, but this could adversely impact IPL's distribution reliability and significantly increase IPL's vegetation management costs and the costs of defending IPL's vegetation management program in litigation, which could have a material impact on IPL's consolidated financial statements.

IPL is a member of the Midwest Independent System Operator, Inc. ("MISO"). The MISO serves as the third-party operator of IPL's transmission system and runs the day-ahead and real-time energy and ancillary services markets ("ASM") for its members.

IPL previously transferred functional control of its transmission facilities to the MISO and IPL's transmission operations were integrated with those of the MISO. IPL's participation and authority to sell wholesale power at market-based rates are subject to the FERC jurisdiction. Transmission service over IPL's facilities is now provided through the Midwest ISO's tariff.

As a member of the MISO, IPL offers its generation and bids its demand into the market on a day ahead basis and settles differences in real-time. The MISO settles energy hourly offers and bids based on locational marginal prices, which is pricing for energy at a given location based on a market clearing price that takes into account physical limitations, generation and demand throughout the MISO region. The MISO evaluates the market participants' energy offers and demand bids optimizing for energy and ancillary services products to economically and reliably dispatch the entire MISO system. The IURC has authorized IPL to recover the fuel portion of its costs from the MISO, including all specifically identifiable ASM costs, through FAC proceedings, and to defer certain operational, administrative and other costs from the MISO and seek recovery in IPL's next basic rate case proceeding. Total MISO costs deferred by IPL as long-term regulatory assets were $80.4 million and $71.0 million as of December 31, 2011 and December 31, 2010, respectively.

Beginning in 2007, MISO transmission owners including IPL began to share the costs of transmission expansion projects with other transmission owners after such projects were approved by the MISO board of directors. Upon approval by the MISO board of directors the transmission owners must make a good faith effort to build and/or pay for the projects. Costs allocated to IPL for the projects of other transmission owners are collected by the MISO per their tariff.

On July 21, 2011, the FERC issued Order 1000, amending the transmission planning and cost allocation requirements established in Order No. 890. Through Order 1000, the FERC:

(1) requires public utility transmission providers to participate in a regional transmission planning process and produce a regional transmission plan;

(2) requires public utility transmission providers to amend their open access transmission tariffs to describe how public policy requirements will be considered in local and regional transmission planning processes;

(3) removes the federal right of first refusal for certain transmission facilities; and

(4) seeks to improve coordination between neighboring transmission planning regions for interregional facilities.

The MISO's approved tariff in part already complies with Order 1000. However, Order 1000 will result in changes to transmission expansion costs charged to IPL by the MISO. Such changes relate to public policy requirements for transmission expansion within the MISO footprint, such as to comply with renewable mandates of other states within the footprint. These charges are difficult to estimate, but are expected to be material to IPL within a few years; however, it is probable, but not certain, that these costs will be recoverable, subject to IURC approval. Through December 31, 2011, IPL has deferred as a regulatory asset $2.3 million of MISO transmission expansion costs.

In 2004, the IURC initiated an investigation to examine the overall effectiveness of Demand Side Management ("DSM") programs throughout the State of Indiana and to consider any alternatives to improve DSM performance statewide. On December 9, 2009, the IURC issued a Generic DSM Order that found that electric utilities subject to its jurisdiction must meet an overall goal of annual cost-effective DSM programs that reduce retail kWh sales (as compared to what sales would have been excluding the DSM programs) of 2% per year by 2019 (beginning in 2010 at 0.3% and growing to 2.0% in 2019, and subject to certain adjustments). The IURC also found that all jurisdictional electric utilities have to participate in five initial, statewide core DSM programs, which will be administered by a third party administrator. Consequently, IPL's DSM spending, both capital and operating, will increase significantly going forward, which will likely reduce IPL's retail energy sales and the associated revenues.

Prior to the issuance of the Generic DSM Order, IPL filed a petition seeking relief for substantive DSM programs. IPL proposed a DSM plan to be considered in two phases. The first phase (Phase I) sought recovery for traditional-type DSM programs such as residential home weatherization and energy efficiency education programs. The IURC issued an Order in February 2010 that approved the programs included in IPL's Phase I request. In addition to IPL's recovery of the direct costs of the DSM program, the Order also included an opportunity for IPL to receive performance based incentives. The second phase (Phase II) sought recovery for "Advanced" DSM programs and was coincident with IPL's application for a smart grid funding grant from the Department of Energy. The Advanced DSM programs included an Advanced Metering Infrastructure communication backbone as well as two-way meters and home area network devices for certain of IPL's customers. In February 2010, the IURC issued an Order that approved IPL's Phase II program, but denied IPL's request to timely recover its expenditures. Instead, IPL would need to seek recovery of the costs incurred under its Phase II program during its next basic rate case proceeding.

In October 2010, IPL filed a petition with the IURC for approval of its plan to comply with the IURC's Generic DSM Order. In November 2011, IPL received approval from the IURC for a new three-year DSM budget totaling $63.1 million that includes the opportunity for performance based incentives.

In 2010, IPL was awarded a smart grid investment grant for $20 million as part of its $48.9 million Smart Energy Project (including smart grid technology), which will provide its customers with tools to help them more efficiently use electricity and upgrade IPL's electric delivery system infrastructure. Under the grant, the U.S. Department of Energy is providing nontaxable reimbursements to IPL for up to $20 million of capitalized costs associated with IPL's Smart Energy Project. These reimbursements are being accounted for as a reduction of the capitalized Smart Energy Project costs. Through December 31, 2011, IPL has received total grant reimbursements of $13.0 million since the 2010 project inception.

The Dayton Power and Light Company ("DP&L")

As a regulated electric utility, DP&L is subject to regulation by the FERC and the Public Utilities Commission of Ohio ("PUCO"). Additionally, construction of large generation facilities and high voltage transmission facilities is subject to regulation by the Ohio Power Siting Board. As indicated below, the financial performance of DP&L is directly impacted by the outcome of various regulatory proceedings before the PUCO and FERC.

DP&L is subject to regulation by the PUCO with respect to the following: its distribution services and facilities; the valuation of distribution property; the sale or abandonment of electric generating facilities; the classification of accounts; rates of depreciation on distribution plant; retail rates and charges; reliability of service, compliance with renewable energy portfolio and energy efficiency program requirements, the issuance of securities (other than evidences of indebtedness payable less than twelve months after the date of issue), and certain other matters. The PUCO also has the authority to consider and approve individually negotiated contracts with customers who meet certain criteria such as job creation, peak demand reduction or energy efficiency programs, or net-metering programs.

DP&L's historic tariff rates for electric service to retail customers (basic rates and charges) were traditionally set and approved by the PUCO after public hearings ("general rate cases") that include the participation of consumer advocacy groups and certain customers. The last general rate case for DP&L was decided in 1991 with rates being phased-in over a three year period (1992-1994). Since that time, DP&L has operated under a variety of regulatory arrangements including PUCO-approved stipulations that had the effect of freezing certain components of its rates for specified periods of time while allowing other components to be reset periodically or added. The PUCO has typically permitted stipulations to operate for whatever period is specified within the stipulation, but it retains the authority to review the rates of any Ohio utility at any time it chooses.

Since January 2001, electric customers within Ohio have been permitted to choose to purchase power under a contract with a Competitive Retail Electric Service Provider ("CRES Provider") or continue to purchase power from their local utility under Standard Service Offer ("SSO") rates established by tariff. DP&L and other Ohio utilities continue to have the exclusive right to provide delivery service in their state certified territories and DP&L has the obligation to supply retail generation service to customers that do not choose an alternative supplier. The PUCO maintains jurisdiction over DP&L's delivery of electricity, SSO and other retail electric services. For customers that choose a CRES Provider, the local utility may issue a joint bill and divides the collected revenue between itself and the CRES Provider based on PUCO rules. The PUCO has issued extensive rules on how and when a customer can switch generation suppliers, how the local utility will interact with CRES Providers and customers, including for billing and collection purposes, and which elements of a utility's rates are "bypassable" (i.e., avoided by a customer that elects a CRES Provider) and which elements are "non-bypassable" (i.e., charged to all customers receiving a distribution service irrespective of what entity provides the retail generation service).

Overall power market prices, as well as government aggregation initiatives within DP&L's service territory, have led or may lead to the entrance of additional competitors in its service territory. During the year ended December 31, 2011, approximately 13% of customers representing 47% of 2011's overall energy usage (kWh) within DP&L's service area had elected to obtain their supply service from CRES Providers. DPL Energy Resources, Inc. ("DPLER"), an affiliated company that is a CRES Provider, has been marketing transmission and generation services to DP&L customers. During 2011, DPLER accounted for approximately 5,731 million kWh and other CRES Providers accounted for about 862 million kWh of the total 6,594 million kWh supplied by CRES Providers within DP&L's service territory. The volume supplied by DPLER represents 41% of DP&L's total distribution volume during 2011. The reduction to gross margin in 2011 as a result of customers switching to DPLER and other CRES Providers was approximately $35.4 million and $22.8 million respectively for DPL. DPL currently cannot determine the extent to which customer switching to CRES Providers will occur in the future and the impact this will have on its operations, but any additional switching could have a significant adverse effect on its future results of operations, financial condition and cash flows.

Several communities in DP&L's service area have passed ordinances allowing the communities to become government aggregators for the purpose of offering retail generation service to their residence. As of February 1, 2012, two communities have filed at the PUCO to implement opt out government aggregation programs.

Substitute SB 221, an Ohio energy bill, went into effect July 31, 2008. This law required that all Ohio distribution utilities file either an Electric Security Plan ("ESP") or a Market Rate Offer ("MRO"). An ESP typically involves establishing a rate structure for SSO that remains relatively fixed for some period of time, but may include trackers or other mechanisms to adjust rates for certain cost changes. Under the MRO, a periodic competitive bid process will set the retail generation price after the utility demonstrates that it can meet certain market criteria and bid requirements. Also, under this option, utilities that still owned generation in the state as of July 2008 are required to phase-in the MRO over a period of not less than six years. Both the MRO and ESP option involve a significantly excessive earnings test ("SEET") based on the earnings of comparable companies with similar business and financial risks. The PUCO has issued extensive regulations under SB 221 addressing the information that must be included in an ESP as well as a MRO, the SEET requirements, corporate separation revisions, rules relating to the recovery of transmission related costs, electric service and safety standards dealing with reliability standards and a statewide line extension policy, and rules relating to advanced energy portfolio standards, renewable energy, peak demand reduction and energy efficiency standards.

In October 2008, DP&L filed an ESP proceeding that was ultimately resolved by stipulation among DP&L, the PUCO Staff, and most interveners (the "ESP Stipulation"). The ESP Stipulation was approved by the PUCO in June 2009. Among other aspects, the ESP Stipulation (i) established rate mechanisms to be in effect from January 1, 2010 until December 31, 2012, including a fuel rider to recover the actual, prudently incurred costs of procuring purchased power and fuel for generation, (ii) continued certain riders including a rate stabilization charge, and an environmental investment charge and (iii) implemented or permitted future filings to implement riders to recover costs associated with its membership in PJM Interconnection, LLC, and for compliance with certain SB 221 requirements such as procurement costs of renewable energy and the implementation of peak demand reduction and energy efficiency programs. The ESP Stipulation clarified that DP&L's earning will be reviewed under the SEET in 2013 based on 2012 earnings results.

Pursuant to the ESP Stipulation, a fuel rider was implemented that tracks the cost of fuel and purchased power costs for supplying retail generation service to SSO customers. These costs are subject to quarterly adjustments to true up costs against revenues collected. On an annual basis, an outside auditor selected by the PUCO audits DP&L and issues a report regarding DP&L's contracting practices to acquire fuel and purchased power and its accounting practices that assign the appropriate portion of costs to SSO customers. In the most recent report for calendar year 2010, the outside auditor recommended and DP&L agreed to implement certain changes in operational and accounting practices, removing certain costs from being included in the rate. The current fuel cost tracking mechanism is set to expire at the end of 2012, at the time when the new ESP or MRO regulatory structure is expected to become effective. An audit of calendar year 2011 will occur in 2012. The outcome of that audit cannot be predicted at this time.

Certain PJM-related costs are recovered through riders that assign costs and revenues from PJM monthly bills to SSO customers based on the ratio of SSO customer load and sales volumes to total retail load and total retail and wholesale volumes. Customer switching to CRES Providers decreases DP&L's SSO customer load and sales volumes and costs. Therefore, increases in customer switching cause more of these PJM-related costs to be excluded from SSO rate recovery. The net charges incurred from PJM that are reflected in SSO rates are trued-up annually.

The ESP Stipulation also provided for recovery of compliance costs for the SB 221 targets relating to advanced energy portfolio standards, renewable energy, peak demand reduction and energy efficiency standards. If any of the SB 221 targets are not met, compliance penalties will apply unless the PUCO makes certain findings that would excuse performance. A partial waiver of the Ohio solar requirement was granted in 2009, and made up in 2010. DP&L fully complied with these requirements in 2010 and expects to be found in full compliance for 2011 when the PUCO reviews DP&L's compliance in early 2012. Over time, the targets gradually increase for advanced energy portfolio standards, renewable energy, demand reduction and energy efficiency standards. DP&L is unable to predict the ultimate future costs of compliance for these requirements.

In 2012, DP&L is required to propose either a new ESP or an MRO to be effective January 1, 2013. It is expected that there will be a docketed proceeding in which intervener groups will participate along with the

PUCO Staff and the Office of the Ohio Consumers' Counsel. Under either regulatory structure, SSO rates will be reset and other retail rates may also be reset. DP&L is unable to predict at the present time what approach may be ultimately approved or the specific mechanisms that may be put into effect under either approach. Depending on those mechanisms, market and economic conditions, and other factors outside DP&L's control, the outcome of this proceeding could be material.

DP&L is a member of the PJM Interconnection, LLC ("PJM"). PJM is a RTO that operates the transmission systems owned by utilities operating in all or parts of Pennsylvania, New Jersey, Maryland, Delaware, D.C., Virginia, Ohio, West Virginia, Kentucky, North Carolina, Tennessee, Indiana and Illinois. Collectively, these utilities serve approximately 58 million people. PJM has an integrated planning process to identify potential needs for additional transmission to be built to avoid future reliability problems. PJM also runs the day-ahead and real-time energy markets, ancillary services market, and forward capacity market for its members. As a member of PJM, DP&L is also subject to charges and costs associated with PJM operations as approved by the FERC.

DP&L transferred functional control of its transmission facilities to PJM in 2004, and transmission service over DP&L's facilities is now provided through the PJM Open Access Transmission Tariff ("OATT").

As a member of PJM, DP&L offers its generation and bids its energy needs into the markets operated by PJM on an hourly basis. DP&L is eligible to sell power to PJM and elsewhere at market-based rates, subject to FERC jurisdiction. PJM settles energy hourly offers and bids based on locational marginal prices, which is pricing for energy at a given location based on a market-clearing price that takes into account physical limitations, generation and demand throughout the PJM region. PJM evaluates the market participants' energy offers and demand bids optimizing for energy products to economically and reliably dispatch the entire PJM system.

PJM operates an organized forward capacity market known as the Reliability Pricing Model ("RPM"). Utilities and other load serving entities are required to demonstrate that they have sufficient generation capacity to serve their retail customers or to purchase such capacity in the periodic RPM auctions. The PJM RPM capacity base residual auction for the 2014/2015 period cleared at a per megawatt price of $126/day for the RTO area encompassing DP&L. The per megawatt prices for the periods 2013/2014, 2012/2013, 2011/2012 and 2010/2011 were $28/day, $16/day, $110/day and $174/day, respectively, based on previous auctions. Future RPM auction results will be dependent not only on the overall supply and demand of generation and load, but may also be affected by congestion as well as by PJM's business rules relating to bidding for demand response and energy efficiency resources in the RPM capacity auctions. Increases in customer switching may cause more of the RPM capacity costs and revenues to be excluded from the RPM retail rate rider calculation. DP&L cannot predict the outcome of future auctions or customer switching. Additionally, while the most recent auction price has increased, it still is low relative to the actual costs that would be incurred to construct new generation or invest in substantial amounts of capital for environmental compliance. Future RPM auction results could have a material impact on DP&L's future results of operations, financial condition and cash flows.

Future costs associated with the construction of large transmission facilities within PJM could be significant. DP&L among other interested parties successfully appealed decisions by FERC on how costs of such new facilities would be allocated across PJM. The 7th Circuit rejected FERC's rationale for allocation and remanded to the FERC for further proceedings. The FERC has not yet issued a final order on remand, and DP&L is unable to predict the ultimate outcome of the proceeding. While the amount of costs assigned to DP&L may vary substantially depending on the final allocation method adopted, the effects are not likely to be material for DP&L financially because the costs are being recovered through a transmission cost recovery rider.

In connection with DP&L and other utilities joining PJM, the FERC ordered utilities to justify transitional charges and payments, known as SECA, effective December 1, 2004 through March 31, 2006, subject to refund. Through this proceeding, DP&L was obligated to pay SECA charges to other utilities, but received a net benefit from these transitional payments from other utilities and market participants. A hearing was held, and an initial decision was issued in August 2006. A final FERC order on this issue was issued on May 21, 2010, that substantially supports DP&L's and other utilities' position that SECA obligations should be paid by parties that used the transmission system during the time frame stated above. DP&L, along with other transmission owners in PJM and the MISO made a compliance filing at FERC on August 19, 2010, that fully demonstrated all payment obligations to and from all parties within PJM and the MISO. Certain aspects of the compliance filing are still under review by the FERC, while others have already been appealed for court review**.** DP&L has entered into bilateral settlement agreements with all parties except one to resolve the matter, which by design will be unaffected by the final outcome of these proceedings. The only unsettled claim is a claim of about $18 million that DP&L has against another entity. It is not known how much of that claim will actually be collected or the timing of any such collection. The results of this proceeding are not expected to have a material effect on the results of operations.

NERC is a FERC-certified electric reliability organization responsible for developing and enforcing mandatory reliability standards, including Critical Infrastructure Protection ("CIP") reliability standards, across eight reliability regions. An audit of DP&L in 2009 covering the period June 18, 2007, to June 25, 2009, identified five Possible Alleged Violations ("PAVs") associated with five NERC reliability requirements of various standards. A mitigation plan and settlement was negotiated, including a non-material payment, which was approved on January 21, 2011 by the FERC. In 2010, DP&L self-reported a single CIP violation, for which a mitigation plan and settlement was negotiated and approved by the FERC in 2011, including a nonmaterial payment. DP&L's next scheduled audit is in December 2012.

Environmental Regulations. See "Environmental and Land Use Regulations" below for a description of the United States Environmental Regulations.

Europe, Middle East & Asia

European Union

Structure of Electricity Market. All European Union ("EU") member states are required to implement EU legislation, although there is a degree of disparity as to how such legislation is implemented and the pace of implementation in the respective member states. EU legislation covers a range of topics which impact the energy sector, including market liberalization and environmental legislation.

The Company has subsidiaries that operate existing generation businesses in a number of countries which are member states of the EU, including the Czech Republic, Hungary, the Netherlands, Spain and the United Kingdom. The Company also has subsidiaries that are in the process of commissioning a generation plant in Bulgaria. Bulgaria became a member state of the EU as of January 1, 2007.

Principal Regulations. The principles of market liberalization in the EU electricity and gas markets were introduced under the 2003 Electricity and Gas Directives. In 2005, the European Commission (the "Commission") launched a sector-wide inquiry into the European gas and electricity markets. To tackle the issues identified in the inquiry and to further improve the regulatory framework for energy liberalization, the Commission launched the Third Energy Package in 2007. In the context of the electricity market, the inquiry has to date focused on identifying issues related to price formation in the electricity wholesale markets and the role of long-term agreements as a possible barrier to entry with a view to improving the competitive situation. In January 2007, the Commission published a proposal for a new common energy policy for Europe. In November 2008, the Commission published a nonbinding second Strategic Energy Review aimed at developing the concept of a common European energy policy. It focused mainly on security of supply and infrastructure development. The Strategic Energy Review proposed reviews of the Gas Storage Directive in 2010 and an update of the Oil Stocks Directives.

In October 2008, the Energy Ministers reached political agreement on the "Third Liberalization Package," which includes five pieces of legislation, Electricity and Gas Directives, Electricity and Gas Regulations and a

Regulation creating a new Agency for the Coordination of Energy Regulators, which will have limited powers to deal with cross-border interconnectors and related issues. This legislation was formally adopted in August 2009 and required implementation on a national level by March 2011.

Environmental Regulations. See "Environmental and Land Use Regulations—International" below for a description of these directives.

Bulgaria

Structure of Electricity Market. The Bulgarian energy sector model allows for trading at regulated prices, at freely negotiated prices between parties or on the organized market. Since an organized market has not evolved yet despite the availability of adequate legislative framework for it, the primary means for wholesale trading is the regulated market, the bilateral transactions market and the Electricity Balancing Mechanism. These arrangements are also supplemented by an imbalance settlement regime.

The Bulgarian power market has evolved from a system where the National Electricity Company ("NEK"), established in November 1991 as a fully state-owned vertically integrated utility, was responsible for the entire cycle of generation, transmission and distribution. After a decade of functioning in this role, NEK was vertically unbundled with a resulting legal separation of generation, transmission and distribution assets into different operating entities. While these structural reforms greatly helped create a competitive electricity sector, there are no actual trading rules to enable the market to operate freely. To ensure accessible customer prices and support to renewable energy supply ("RES") producers and the highly efficient cogeneration assets, NEK is still acting as single buyer, purchasing the majority of power generated in Bulgaria and then selling the power to distribution companies and to some of the transmission network-connected consumers. NEK also owns the biggest hydro-electric and pump storage generation facilities in Bulgaria.

While the transmission system in Bulgaria remains under NEK's formal ownership, to comply fully with EU legislation, NEK has spunoff transmission operations (i.e., system operation, balancing market administration and systems' operation and maintenance) to the Electricity System Operator. The system also allows for regulated third-party access.

Principal Regulators. The State Energy and Water Regulatory Commission ("SEWRC") established in 1999 is the independent regulator for both the energy and water markets. SEWRC's key responsibilities are:

- Licensing activities in the electricity, heat and natural gas sectors;
- Regulating electricity, heat and natural gas prices (including those from RES and CHP power sources);
- Regulating interconnection to distribution and transmission networks; and
- Issuing of certificates of origin and green certificates for the electricity produced from RES and co-generation.

Principal Regulations. Bulgaria is at a juncture of adopting legislative packages that cover three key European policy goals—energy independence (Directive 2009/28/EC), environmental sustainability through GHG emission control (Directive 2009/29/EC) and market liberalization (Directive 2009/72/EC). In line with these EU-mandated goals, the government of Bulgaria has set the following key priorities: a 20% reduction of the energy intensity of GDP by 2013 and a 50% reduction by 2020; increased renewables' share of the total energy consumption to 12% by 2013 and to a minimum of 16% by 2020; and competitive energy market through promoting new generation entry, security of supply, and sustainable development. A key milestone would be a 30% increase of bilateral contracts in the electricity market by 2013.

A key law that sets the stage for the above priorities is the Bulgarian Energy Act developed in 2004 (the "BEA") with a view to a transparent and predictable regulatory environment to promote further liberalization through an independent regulatory authority. The BEA creates a framework for viable commercial companies in the sector through more investment, greater autonomy of SERWC and more effective commercial restructuring. The BEA is structured so that the market can shift away from the single-buyer model into a more market-oriented third-party network access model that allows for trading at regulated or freely negotiated prices, as well as at a free market exchange. To be in full compliance with the EU Third Energy Package, the BEA is being amended in order for the electricity market to be fully liberalized under clear regulatory rules and sustainable market mechanisms. Recent amendments to the BEA are making clear the commitment of the government to honoring long-term contracts for power purchasing with generators whose investments have helped upgrade the national asset base.

To help further develop the energy market, the SERWC developed new Trading Rules, adopted in 2010, where generators, consumers and grid operators are organized in balancing groups for the most cost-effective balance between energy supply and consumption. An underlying principle of the Trading Rules will be the presence of a "Day-ahead" market (a departure from the existing practice of weekly notification schedules). Importantly, the Trading Rules will also establish the principles for the Bulgarian power exchange, all in line with the EU's Third Energy Liberalization legislation.

Environmental Regulations. The main environmental regulations reflect the implementation of EU environmental directives. In January 2007, Bulgaria introduced EU Emissions Trading Scheme ("ETS") as the main mechanism for meeting Kyoto Protocol GHG reduction commitments. The Bulgarian Environmental Protection Act, amended on September 27, 2005, and all secondary legislation promulgated pursuant to it, have incorporated all EU and Kyoto emission reduction commitments. The Bulgarian National Allocation Plan ("NAP") allows a total of 42.3 million tonnes of CO_2 for the entire volume of fossil fuel-based generation in the country. The AES Galabovo coal-based power plant is permitted by the NAP to generate 80% of its projected generation for 2011 and 2012. The portion of CO_2 generation that is not covered by NAP will be billed directly to NEK.

AES-3C Maritza East 1 EOOD ("AES-3C") expects to receive, in accordance with the NAP its allocation of free emission quota which AES-3C was assured to receive by the Bulgarian Government in 2011. To date, AES-3C has not yet received its free allocations for the emitted volumes. AES-3C believes it is entitled to the allocation or that costs for the allocations if not provided would be borne by contractual third parties. However, if AES-3C does not receive such allocations within its reporting deadline of March 31, 2012, AES-3C may be held responsible for compliance costs in the form of penalties, in addition to the responsibility to purchase, on a free market basis, European Union Allowances for the said volumes, which may be material to the results of its operation. AES-3C is continuing to work with the relevant Bulgarian authorities towards opening its account at the National Registry of Carbon Quota and having free allocations deposited into it.

Bulgaria is also subject to the Large Combustion Plant Directive (2001/80/EC) ("LCPD"), which aims to reduce particulate emission by controlling SO_2, NO_X and dust from large combustion plants. The LCPD allows for existing plants to opt for exemption from the emission level values, as long as the operator undertakes not to operate for more than 20,000 hours starting from January 1, 2008 and ending no later than December 31, 2015. Major rehabilitation work has been taking place across units of various Bulgarian thermal power plants in the last decade. The rehabilitated Maritza East 2 complex is now fitted with electrical filters for capturing dust and Flue Gas Desulphurisation ("FGD") units (more than 94% efficiency). The AES Galabovo power plant is equipped with a state-of-the-art wet FGD system that ensures up to 98% of SO_2 removal.

Bulgaria is dependent on foreign imports for 70% of its primary fuel sources, which makes exploration of renewable energy sources of paramount importance for the country's achievement of energy independence and environmental objectives. Bulgaria's EU-mandated renewable targets have been met mostly by hydroelectric power plants with limited contribution to the fuel mix by wind energy and even less from biomass. The main goal of the Renewable and Alternative Energy Sources and Biofuels Act of 2007 is to encourage generation from and grid interconnection of installations utilizing renewable energy sources.

Material Regulatory Actions. In connection with Bulgaria's accession into the EU, the European Commission (the "Commission") has opened an investigation into alleged anticompetitive behavior and possible restrictions of competition in the Bulgarian electricity markets. The current focus of the Commission's investigation is NEK. As part of its investigation, the Commission is attempting to determine whether NEK's long-term contracts are anticompetitive, including its long-term PPAs with AES' Bulgarian entities, AES Maritza and AES Geo Energy. Accordingly, the Commission has issued separate information requests to AES Maritza and AES Geo Energy about their respective PPAs with NEK. While these particular requests were voluntary, both AES Maritza and AES Geo Energy have cooperated in good faith with the Commission, have provided the requested information and have met with the Commission in order to provide background and any further required information about the projects. The Commission has clearly specified that neither AES Maritza nor AES Geo Energy were the target of the investigation. We believe the Commission is partly concerned that long-term PPAs could pose a problem with respect to the liberalization of Bulgaria's electricity markets but we believe that the projects and their respective PPAs did not tie up capacity but created capacity that would not otherwise exist. However, if the Commission determined that PPAs are anticompetitive, they could take actions up to and including termination of the AES Maritza PPA, which could have a material adverse impact on AES Maritza and our results of operations and financial condition.

Potential or Proposed Regulations. The AESB Act referred to above is currently being amended in order to better incorporate the EU principles set forth in Directive 2009/29/EC. Recent draft amendments to the AESB Act ensure predictability for off-take tariffs for wind project investments that have been undertaken in the last several years (including the AES-owned Saint Nikola Wind Farm) as well as create new development opportunities for solar power, including the new solar power projects in the Bulgaria pipeline of AES Solar.

Hungary

Structure of Electricity Market. The Hungarian market has one main interconnected system. The state-owned electricity wholesaler, MVM, is the dominant exporter, importer and wholesaler of electricity. MVM's affiliated company, MAVIR, is the Hungarian transmission system operator. Currently, Hungary is dependent on energy imports (mainly from Russia) since domestic production only partially covers consumption. The wholesale market is legally liberalized, although it remains dominated by MVM owing to MVM's access to and control over a significant portion of the Hungarian generating facilities. The spot market is relatively illiquid with trading dominated by over-the-counter or bilateral contracts. Relative to more western parts of Europe, the volumes traded are smaller and typically for shorter durations, although contracts with a duration that is greater than one year are available.

Principal regulators. Magyar Energia Hivatal ("MEH") is the government entity responsible for regulation of the electricity industry in Hungary. The Ministry of National Development oversees the activities of the MEH.

Principal Regulations. The main regulations in Hungary are those being implemented under EU directives; the adoption of the Hungarian Electricity Act in 2007, which became effective January 1, 2008, was the final legislative step to implement a fully liberalized electricity market. By virtue of the Hungarian Electricity Act, all customers are eligible to choose their electricity supplier. In the competitive market, generators sell capacity to wholesale traders, distribution companies, other generators, electricity traders and eligible customers at an unregulated price.

Environmental Regulations. The main environmental permitting regulation is the Integrated Pollution Prevention Control ("IPPC"). The IPPC Directive is based on several principles, namely (i) an integrated approach to permitting, (ii) Best Available Techniques ("BAT"), (iii) flexibility and (iv) public participation. The integrated approach requires permits to take into account the whole environmental performance of the plant, including, emission to air, water and land, generation of waste, use of raw materials, energy efficiency, noise, prevention of accidents and restoration of the site upon closure. The purpose of the IPPC Directive is to ensure a high level of protection of the environment taken as a whole. The permit conditions including emission limit values must be based on BAT as defined in the IPPC IPPC Directive. To assist the licensing authorities and companies to determine BAT, the Commission organizes an exchange of information between experts from the EU Member States, industry and environmental organizations. This work is coordinated by the European IPPC Bureau of the Institute for Prospective Technology Studies at the EU Joint Research Centre in Seville, Spain. This results in the adoption and publication by the Commission of the BAT Reference Documents (the "BREFs"). The IPPC Directive contains elements of flexibility by allowing the licensing authorities, in determining permit conditions, to take into account the technical characteristics of the installation, its geographical location and the local environmental conditions. Finally, the Directive ensures that the public has a right to participate in the decision-making process, and to be informed of its consequences, by giving the public access to permit applications in order to provide their opinions, permits, results of the monitoring of releases and the European Pollutant Release and Transfer Register ("E-PRTR"). E-PRTR provides emission data reported by Member States accessible in a public register, which is intended to provide environmental information on major industrial activities. E-PRTR has replaced the previous EU-wide pollutant inventory, the so-called European Pollutant Emission Register.

Material Regulatory Actions. Shortly before its accession to the EU, the Hungarian government notified the Commission of arrangements concerning compensation to the state-owned electricity wholesaler MVM. The Commission decided to open a formal investigation in 2005 to determine whether any government subsidies were provided by MVM to its suppliers which were incompatible with the EU's market. In June 2008, the Commission reached its decision that these PPAs, including AES Tisza's PPA, contain elements of illegal state aid. The decision required MVM to terminate the PPAs within six months of the June 2008 decision, and to recover the alleged illegal state aid from the generators by April 2009. AES Tisza is challenging the Commission's decision in the Court of First Instance of the European Communities. Referring to the Commission's decision, Hungary adopted act number LXX of 2008 which terminates all long-term PPAs in Hungary, including AES Tisza's PPA, as of December 31, 2008, and requires generators to repay the alleged illegal state aid that was allegedly received by the generators through the PPAs, and provides for the possibility to offset the generators stranded costs from the repayable state aid. The MEH issued its Resolution No. 342/2010 pursuant to which it stated AES Tisza did not receive illegal state aid.

At the end of 2006 and for all of 2007, the Hungarian government reintroduced administrative pricing for all electricity generators, overriding PPA pricing, including the pricing in AES Tisza's PPA. In January 2007, AES Summit Generation Limited ("AES Summit"), a holding company associated with AES Tisza's operations in Hungary, and AES Tisza notified the Hungarian government of a dispute concerning its acts and omissions related to AES' substantial investments in Hungary in connection with the reintroduction of the administrative pricing for Hungarian electricity generators. In conjunction with this, AES Summit and AES Tisza have commenced International Centre for Settlement of Investment Disputes ("ICSID") arbitration proceedings against Hungary under the Energy Charter Treaty in connection with Hungary's reintroduction of the administrative pricing for Hungarian electricity generators. In the meantime, pursuant to the new Electricity Act in force from January 1, 2008, administrative pricing for electricity generators was subsequently abolished. The ICSID arbitration panel issued the final determination on September 23, 2010, pursuant to which AES' claim was dismissed. AES challenged the panel's decision and requested the annulment thereof.

In 2008, Hungary introduced a special tax to be levied on energy companies including companies such as AES Tisza. The rate of the special tax was 8% and, in 2010, was extended until 2013. Hungary also introduced a further tax on certain industries, including energy companies (the "Crisis Tax"). The rate of the Crisis Tax for energy companies is 1.05% of the net sales revenues.

Kazakhstan

Structure of Electricity Market. In Kazakhstan, the electricity sector is divided into wholesale and retail markets. The wholesale electricity market of Kazakhstan is based on bilateral contracts conducted through an over-the-counter market and KOREM's centralized trading system. In the retail market, the power distribution and supply functions are unbundled and retail customers with consumption of one MW or more have a right to buy the electricity directly from power plants or retail supply companies.

Principal Regulators. The government of Kazakhstan approves subordinate acts in the power sector (licensing requirement, technical regulations, market rules, tariff methodologies for natural monopolies, etc.) and determines the level of price caps for groups of power plants.

The Ministry of Industry and New Technologies (the "Ministry") is the central executive body responsible for developing state policy in the power sector and conducting technical regulation. As a part of price cap regulation, the Ministry is responsible for determining groups of power companies for each price cap, annual adjustments of price caps and signing agreements on investment obligations with power plants.

The Agency for Regulation of Natural Monopolies (the "Regulator") acts as a regulator of industries considered to be "natural monopolies" (transmission and distribution of oil, gas, electricity and heat, railroads, airports, etc.). In the power industry, the Regulator is responsible for the approval of tariffs for heat generation, distribution and supply, electricity transmission and distribution, as well as end-user tariffs for dominant companies in the retail power market. The Regulator grants different licenses in the power sector such as licenses for generation, distribution and retail activities.

The Agency for Protection of Competition (the "AZK") monitors power market participants to determine entities with a dominant position and detect violations of antimonopoly legislation.

The Ministry of Environmental Protection (the "Environmental Ministry") is responsible for environmental policy, grants emission permits and evaluates the environmental impact of new projects.

JSC KEGOC is a state-owned electricity transmission company, which also acts as the system operator with a central dispatch management function and as the operator of the balancing market.

Principal Regulations. The following major laws and regulations govern the electricity industry:

- Law "On the Power Industry" (the "Kazakhstan Electricity law");
- Law "On Natural Monopolies and Regulated Markets";
- Law "On Competition";
- Law "On Supporting the Use of Renewable Energy Sources";
- Environmental Code;
- Law "On Licensing";
- Resolution of the Government of the Republic of Kazakhstan "On Approval of the Price Caps"; and
- The state program of power industry development in 2010-2014.

Continuous changes in the law and regulations result in contradictions between different laws and regulations. This in turn results in an uncertain regulatory environment in the power sector.

The key elements of price cap regulation of power plants are as follows: (i) the Ministry has determined the power plant grouping based on the plant type, equipment, fuel and distance from coal mines (thirteen groups of power plants were defined); (ii) the Ministry has proposed to the government the price cap for each group based on actual prices in 2008 and the level of investment required, and the government has approved price caps for each group of power plants for the seven-year period from 2009-2015; (iii) the Ministry may propose to the government additional annual adjustments to price caps to reflect inflation and investment requirements within any group or a power plant may apply for an individual investment tariff to the Ministry and the Regulator; (iv) a power plant determines its investment obligations at its own discretion and signs an agreement with the Ministry on investment obligations; and (v) the price cap and individual investment tariff regime do not constitute a price guarantee and power plants should sell to consumers at the competitive market price but not higher than their group price cap or an individual investment tariff. Only exports of power and sale of ten percent of generation through a centralized trading system are exempt from this restriction. Power trading activities are restricted and power plants are allowed to conduct trading activities to provide electricity supply to their consumers during emergency shutdowns.

The Regulator approves and regulates all tariffs for heat generation, transmission and supply, as well as electricity transmission and distribution tariffs on a cost-based methodology. Power trading companies, which the AZK considers dominant entities, must notify the Regulator of any proposed increase in their tariffs and the Regulator has the right to veto such proposed tariff increases. Furthermore, the Regulator has the right to request a decrease in the applicable tariffs.

The AZK determines the borders of electricity markets at its own discretion, which does not correspond with the provisions of the Kazakhstan Electricity Law, and designates entities with dominant market power. The AZK may consider the tariff of a power plant which is in compliance with price cap regulation to be an excessive monopolistic price of a dominant entity and impose sanctions, as happens from time to time to AES' generating companies.

Environmental regulations. The Environmental Ministry is responsible for environmental policy and environmental regulations. The Environmental Ministry issues environmental permits, sets emission limits and organizes ecological control in the forms of state environmental impact assessments and independent ecological audits. The Environmental Ministry reviews permit applications for power plants and, after conducting the environmental impact assessment, grants environmental permits for industrial waste, air and water discharges for a period of not more than three years. In December 2011, Kazakhstan adopted amendments to the Ecological Code to introduce carbon regulation starting in 2013 to comply with the Kyoto Protocol, which was ratified by Kazakhstan. Carbon regulation will likely impose allocation of carbon quotas and a carbon trading system. In addition, a violation of environmental requirements may lead to criminal liability and fines.

Material Regulatory Actions. In December 2010, the Environmental Ministry refused to sign agreements on investment obligations with AES UK HPP and AES UK CHP for 2011 and has requested to amend the existing agreement on investment obligation from AES Shulbinsk HPP in 2011. The Environmental Ministry has demanded that AES power plants in Kazakhstan undertake an additional obligation to spend all profits in new investment projects. The financial police have started criminal investigations against AES employees on alleged violations of competition law for the use of price caps in the first part of 2009 and during 2011 without signed agreements on investment obligations.

In December 2011, the Environmental Ministry refused to sign agreements on investment obligations for 2012 with AES UK HPP, AES UK CHP and AES Shulbinsk HPP. In addition, the Environmental Ministry proposed to all Kazakhstan power plants and coal mines to consider freezing prices during the first quarter of 2012 due to the upcoming parliament elections. The use of 2012 price caps without signed agreements on investment obligations may lead to further sanctions by the AZK and other state authorities against our businesses.

In November 2011, AES sent notification to the Kazakhstan government regarding the early termination of the management agreement for the power distribution company EK Disco and its affiliate retail company Shygysenergotrade. Transfer of management rights to the Kazakhstan government should be completed within 180 days. AREM has refused to grant the necessary tariff increase to EK Disco and Shygysenergotrade for 2012 owing to the parliamentary election. Both of these companies are major customers of AES power plants, and the change of management control and AREM refusal on tariffs may have a negative effect on our financial results.

The AZK has designated all AES power plants in Kazakhstan as dominant entities in the eastern Kazakhstan and Pavlodar regions. Shygysenergotrade LLP has also been designated by the AZK as a dominant entity in the eastern Kazakhstan retail market. AES has challenged these designations but so far has been unsuccessful in having the designations overturned. The AZK is conducting other investigations into alleged violations by AES businesses in Kazakhstan of antimonopoly legislation such as excessive monopolistic prices and ungrounded refusal to supply power to certain customers. AES believes that the investigations per se and allegations made by the AZK in the course of investigations are without merits, and AES is vigorously challenging the unfounded actions of the AZK. However, if AES Kazakhstan does not prevail in these proceedings, there could be a material impact on these businesses and our results of operations in 2012. AES has started an arbitration case in the ISCID against Kazakhstan, where fines and sanctions imposed on AES businesses by AZK in previous years are challenged.

Potential or Proposed Regulations. The Ministry plans to introduce a capacity market starting in 2015 to support new investments in generating assets and the draft of the law is under review by the Kazakhstan parliament. The capacity market should replace price cap regulation. The details of the capacity market regulations will be determined by government subordinate acts and may have a material impact on our financial results.

The Ministry and the Regulator have drafted amendments to the Kazakhstan Electricity Law to increase sanctions for any failure to implement the investment program or comply with the price cap regulation. The absence of a signed agreement on investment obligations will limit a power plant's right to apply tariffs up to the price cap, such that the electricity tariff of a power plant cannot not exceed its 2008 level. It is expected that this regulation will come into force in January 2012. As a result, we may be required to make significant capital investments and to incur other expenses in order to obtain the benefits of the price caps and avoid sanctions.

Turkey

Structure of Electricity Market. The wholesale generation and distribution market in Turkey is primarily a bilateral market dominated by state-owned entities. The state-owned Electricity Generation Company ("EUAS") and its subsidiaries constitute approximately 24 GW of generation capacity and represent approximately 47% of the market. Private producers (with public offtake) account for another 18%, and auto producers and merchant power plants the remaining 35%. There is an hourly balancing spot market, with prices typically differing from hour to hour, which is growing and has a capacity of 150 Gigawatt hours ("GWh") of daily trade on average. The automatic price mechanism, which is meant to halt the government subsidization, has been approved and implementation commenced in July 2008. With this mechanism, all major cost items (foreign exchange, gas price increases, and inflation, among others) are expected to be reflected in the tariff. As a result, midterm market wholesale prices are expected to converge to the current spot market prices. Distribution companies can procure 855% of their needs from TETAS and EUAS but can also source up to 15% from other sources. Additionally, eligible customers, using greater than 30 MWh annually, can contract with the private wholesale companies and private power plants. In 2007, Turkey introduced a "renewable feed-in tariff that sets a floor for renewable generation (solar, biomass, geothermal, wind and small-scale hydroelectricity) for the first ten years of operating. The floor is between $73/MWh to $133/MWh depending on the technology and decreed by EMRA each year. AES' Turkey hydro assets fall under the renewable feed-in tariffs. The Turkish government has also announced plans to privatize all the state-owned generation assets, other than certain large hydroelectric plants.

Principal Regulators. The transmission network is owned and controlled by TEIAS, the State Transmission Company. TETAS, the Wholesale Trading Company, sets wholesale prices based on average procurement costs from EUAS, auto-producers and Build Operate/Build Operate Transfer/Transfer of Operating Rights producers. This wholesale price represents the buying price for 21 distribution companies under the current Transition Period Contracts ("TPC") which are expected to expire by 2013. Under TEDAS, there were 20 regional distribution companies. In 2006, four of them were privatized and transferred to the new owners in 2008. Another five of them were privatized in 2009 and transferred to the new owners in 2010. In 2010, the remaining ones were tendered and three of them were transferred to new owners in 2011, while the remaining distribution companies are awaiting approval for handover. In 2010, the Turkish Privatization Administration finished the bidding process of all regional distribution companies. Retail electricity prices are calculated and proposed by the distribution companies and then approved by the electricity market regulatory authority, EMRA.

Principal Regulations. Turkish Electricity Market is governed by the following laws: Electricity Market Law—EML (2001), Renewable Energy Law—REL (2005), Energy Efficiency Law—EEL (2007), Nuclear Power Plant Law—NPPL (2007), and Geothermal Law—GL (2007).

Environmental Regulations. Turkey is listed in Annex-I to the United Nations Framework Convention on Climate Change ("UNFCCC") with special circumstances that place Turkey in a position that is different from other Annex-I Parties. On February 16, 2009, the Turkish President ratified the law concerning Turkey's accession to the Kyoto Protocol. In parallel to the EU accession process, Turkey enacted Large Combustion Plants Directive in June 2010 which is similar to the EU legislation.

Ukraine

Structure of Electricity Market. The electricity sector in Ukraine is regulated by the National Energy Regulatory Commission ("NERC"). Electricity costs to end-users in Ukraine consist of three main components: (1) the wholesale market tariff is the price at which the distributor purchases energy on the wholesale market, (2) the distribution tariff covers the cost of transporting electricity over the distribution network, and (3) the supply tariff covers the cost of supplying electricity to an end-user. The total cost permitted by the regulator under the distribution and supply tariff each year is referred to as the DVA. The distribution and supply tariffs for all distribution companies in Ukraine are established by the NERC on an annual basis, at which time DVA and electricity distribution volumes in the tariff are adjusted. A change in the DVA methodology was effected at the end of 2007 with respect to the treatment of wages and salaries such that the adjustment for inflation was replaced by an allowance based on the average industrial wage in the country and normative quantity of personnel.

Principal Regulations. In 2006, NERC authorized two 25% increases in end-user tariffs for residential customers. From 2006 through 2011 there have been no further changes in residential end-user tariffs and the tariff covered approximately 30% of real energy costs. In 2011 there were two tariff increases for residential customers with the introduction of two tariff blocks based on consumption level, resulting in 28-30% of real energy cost coverage by residential customers. The wholesale electricity market price increased by 49% in 2008, by 8.5% in 2009, by 18% in 2010, and by 23% in 2011. In the course of 2010-2011, a simultaneous increase in wholesale market price and pressure on the nonresidential end-user tariff growth resulted in the debt to distribution companies by NERC on compensation of losses for supplying energy to residential customers at privileged tariffs.

A comprehensive review of the distribution tariff methodology addressing issues of revaluation of the rate base, operational expenses coverage on tariffs, the rate of return and introduction of regulatory incentives to increase the quality of service was initially expected to take place at the end of 2008. However, since late 2008 and then on an annual basis, NERC has been introducing minimal changes into the tariff methodology to be valid for just one year, including for 2011, setting the rate of return on initial investment at the level of 15% after tax, wages and salaries treatment remaining as per the mechanism introduced in 2007, and material operational expenses subject to indexation by inflation. A similar extension of provisions for 2012 is expected to be approved. Development and approval of a comprehensive methodology are expected to take place during 2012 to be introduced in 2013.

In 2010, the President of Ukraine announced the list of reforms for implementation up through 2014 in all sectors of the economy, including the electric industry. According to such reforms, there are plans to (i) develop new tariff methodology in 2011; (ii) increase tariffs for residential customers; (iii) commence elimination of cross subsidies; (iv) make changes to legislation to improve customers' payment discipline; (v) privatize state-owned distribution companies and generation companies; and (vi) introduce a new market structure based on bilateral agreements and balancing market, etc. The declared plan of reforms is delayed in implementation.

In 2009, the Supreme Court of Ukraine took a preliminary position affecting distribution companies in the Ukraine, including AES Kievoblenergo and AES Rivneoblenergo, where under it required that certain network commercial losses of power that were previously treated as tax deductible could no longer be treated as such. This position, if maintained, may have a material effect on AES Kievoblenergo and AES Rivneoblenergo. The Company expects that the Supreme Court of Ukraine may clarify its position in the future, and the proceedings in respect to AES Kievoblenergo and AES Rivneoblenergo are not likely to be finally resolved for another several years.

United Kingdom

Structure of Electricity Market. On March 21, 2007, the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 was enacted, which provided for the introduction and regulation of a single wholesale electricity market (the "SEM") for Northern Ireland and the Republic of Ireland that began operation in November of 2007. Revenue from the SEM includes a regulated capacity and an energy payment based on the system marginal price. Bidding principles insist bids are cost-reflective and are based on short run marginal cost. Total annual capacity payments are calculated as the product of the annualized fixed cost of a best new entrant peaking plant multiplied by the capacity required to meet the security standard. This accumulated capacity is then distributed on the basis of plant availability throughout the year on a per trading period basis.

Certain generating units (Kilroot GTs 1 and 2 and Ballylumford units 4, CCGT units 10 & 20 and GTs 1 and 2) are contracted under long-term PPAs to NIE Energy Limited terminating on various dates. The CCGT units are subject to extension by NIEE between March 2012 and 2024. All of the PPAs can be cancelled under direction from NIAUR from November 1, 2010 with six months' notice other than the Ballylumford 10 and 20 units which can be cancelled from April 1, 2012. All other units (Kilroot units K1 and K2 whose PPAs terminated in November 2010, GTs 3 and 4 and Ballylumford units 5 and 6) participate as merchant units in the SEM as described above.

The effect of this on the Northern Ireland units operated as merchant plants in the SEM depends largely on the relative costs of coal and gas. The relevant units receive capacity payments under the SEM.

For the units with PPAs in place, Kilroot and Ballylumford are neutral with respect to the cost of fuel as this is passed through to its PPA counterparty as an element of the payments made to the respective units based on their availability.

Principal Regulators. Kilroot and Ballylumford are located in Northern Ireland, which is part of the United Kingdom, and are subject to regulation by the Northern Ireland Authority for Utility Regulation ("NIAUR").

Principal Regulations. The principal legislation is The Electricity (Northern Ireland) Order 1992 under which the Generation Licenses of Kilroot and Ballylumford are granted.

Environmental Regulations. The Kilroot and Ballylumford plants operate under permits granted under the Pollution Prevention Control Regulations (NI) 2003.

The Industrial Emissions Directive was approved by the European Parliament on July 7, 2010 and is expected to become law by 2014. This Directive sets stricter limits on the emissions of pollutants such as NO_X, SO_2 and particulate matter and requires further reductions in such emissions by January 2016. The combined package of the Industrial Emission Directive, National Emissions Ceiling Directive and Best Available Technique requirements forms a Regulatory Framework for all electricity generation from Large Combustion Plants for the period from 2016 onwards, principally comprising coal-fired, gas-fired, oil-fired and biomass-fired plants. The following steps may be required in respect of Kilroot: (i) fit selective catalytic reduction and comply with the new limits by 2023, at which time there may be another review; (ii) opt out and run under a limited life derogation for a maximum of 17,500 hours; and (iii) opt into a Transitional National Plan which shall apply from January 1, 2016 until June 30, 2020, after which point there will be an option to comply with Emission Limit Values or Closure or run for 1500 hours per year.

Currently, the Ballylumford units 4, 5 and 6 (the B Station) are scheduled to close by the end of 2015 under the Large Combustion Plant Directive; however, there is the possibility that these units may be adapted to be compliant under the Industrial Emissions Directive. The exact details will not be known until the Industrial Emissions Directive is implemented.

With regard to the C Station at Ballylumford, gas turbines using light oils and middle distillates as liquid fuels are subject to an emission limit value for NO_X of 90mg/Nm3. GT10 (part of the CCGT plant) is currently permitted to 120mg/m3 on distillate. This could mean that possible modifications are required to be able to continue to run distillate as a dual fuel.

There are transitionary arrangements within the Industrial Emissions Directive to allow plants to manage the introduction of the new limits; large combustion plants may have until July 2020 to meet the requirements. Such arrangements appear attractive to AES and would allow the units to operate without substantial capital investment on a restricted load factor until the end of 2020. After 2020, AES would be required to comply with the new emissions limits in order to continue operations.

The Environmental Liability Directive came into force in Northern Ireland on June 24, 2009 and is aimed at the prevention and remedying of environmental damage. An operator will be held financially liable if it carries out certain activities which cause environmental damage, or where there is an imminent threat of such damage, regardless of whether it intended to cause the damage or was negligent. This includes IPPC permitted installations. In practice there should be no change to AES' operations as a result of the coming into force of the Environmental Liability Directive.

Material Regulatory Actions. NIAUR published two consultation papers in 2011 regarding the cancellation of Generating Unit Agreements ("GUAs") in place between PPB and certain generators which could impact various long-term PPAs in Northern Ireland including those at Kilroot and Ballylumford The recommendation from these consultation papers was that NIAUR would not cancel any of the remaining GUAs but keep them under review.

Potential or Proposed Regulations. In November 2010, the Council of the EU approved a revised directive on industrial emissions so as to reduce emissions of pollutants that are harmful to the environment and associated with cancer, asthma and acid rain. The industrial emissions directive seeks to prevent and control air, water and soil pollution by industrial installations. It regulates emissions of a wide range of pollutants, including sulfur and nitrogen compounds, dust particles, asbestos and heavy metals. The directive is aimed at improving local air, water and soil quality, not at mitigating the global warming effects of some of these substances. The review integrates seven directives into a single legal framework and provides for a more harmonized and rigorous implementation of emissions limits associated with the best available technology, so-called BAT. Deviations from this standard are only permitted where local and technical characteristics would make compliance disproportionately costly. The recast also tightens emission limits for NO_X, SO_2 and dust from power plants and large combustion installations in oil refineries and the metal industry. New plants must apply the BAT beginning in 2012, four years earlier than initially proposed. Existing plants have to comply with this standard from 2016, though a transition period is foreseen. Until June 30, 2020, member states may define transitional plans with declining annual caps for NO_X, SO_2 or dust emissions. Where installations are already scheduled to close by the end of 2023 or operate less than 17,500 hours after 2016, they may not need to upgrade. Member States have two years to explain this Directive.

Middle East & Asia

China

In 2005, the National Development and Reform Commission ("NDRC") released interim regulations governing on-grid tariffs, along with two other regulations governing transmission and retail tariffs. The On-Grid Tariff Measures specify different rules for the determination of on-grid tariffs before and after the implementation of competitive pricing. Before the implementation of competitive pricing, the on-grid tariffs shall be appraised and ratified by the pricing authorities by reference to the economic life of power generation projects and determined in accordance with the principle of allowing power generators to cover reasonable costs and to obtain reasonable returns. Such costs were defined to be the average costs in the industry and reasonable returns will be calculated on the basis of the interest rate of China's long-term Treasury bond plus certain percentage points. After the establishment of competitive regional power markets, the on-grid tariffs of electricity generation companies which participate in the competitive market shall principally consist of two components: the capacity charge, which is to be determined by the tariff regulatory authority, and the energy charge, which is to be determined by market competition. However, no implementation rules have been issued to introduce the competitive pricing which is still pending as of now. The Retail Tariff Measures aim to reform the various classes of tariff for end-users into three categories: residential electricity, electricity used in agricultural production and electricity used in industry, commerce or for other purposes. The tariff for each category is fixed per voltage class. The tariffs shall be determined with consideration to the fair sharing of the burden, the efficient adjustment of the demand for electricity and the public policy objectives.

In addition to the foregoing tariff-setting mechanism, China's central government also issued a tariff adjustment policy allowing the on-grid tariffs to be pegged to the fuel price in the case of significant fluctuations in fuel price. Seventy percent of the increase in fuel costs may be passed through in the tariff. The tariffs of coal-fired facilities in China were increased in 2005, 2006, 2008, 2009 and 2011 pursuant to this policy to alleviate the escalation of fuel price; however, such adjustments were obtained from the regulatory authorities only after a time lag and fell short of compensating all businesses for coal price increases in recent years. There was no catch-up tariff adjustment in 2010 pursuant to the foregoing policy.

Pursuant to the "Renewable Energy Law of China," which came into effect on January 1, 2006, and was amended on December 26, 2009, renewable resources such as wind, solar, biomass, geothermal and hydroelectric power enjoy complete and unrestricted generation and dispatch, and local grid interconnection is mandated to such plants. To implement the Renewable Energy Law, on August 2, 2007, various central government agencies jointly issued the "Temporary Measures for Dispatching Electricity Generated by Energy Conservation Projects". Under this regulation, power plants are categorized into groups and assigned priority relative to other groups of power plants. The first group is renewable energy power plants, namely wind, hydroelectric, solar, biomass, tidal-wave, geothermal and landfill gas power plants that satisfy certain environmental standards. The second group is nuclear power plants. The third group is power plants using "modern coal" which includes cogeneration power plants, and power plants utilizing residual heat, residual gas, coal-gangue (or waste coal) and coal mine methane. The last three groups are natural gas, conventional coal and oil-fired power plants. As a result, power plants using renewable resources will enjoy priority dispatch over power plants using fossil fuels. The amendment to the Renewable Energy Law requires that the local grid companies (i) abide by the periodic targets developed by the government for the proportion of power to be generated by renewable energy sources as compared to the total electricity generation and (ii) to purchase all electricity generated by renewable resources. This is in line with the requirement that renewable energy power plants enjoy unrestricted generation and dispatch under the Renewable Energy Law, as well as the Chinese government's policy objective to encourage comprehensive utilization of resources in an energy efficient and environmentally friendly manner.

In 2007, the Chinese government issued a number of rules and procedures that govern the shutdown of small coal or oil-fired power plants. The types of plants to be shut down include: (i) power plants with a capacity under 50 MW, (ii) power plants with a capacity of up to 100 MW which are more than 20 years old, (iii) power plants with a capacity of up to 200 MW whose equipment has reached the end of its useful life, and (iv) power plants that have coal consumption rates that are higher than either 10% above the applicable provincial average or 15% above the national average. The shutdown procedures have been set in place to ensure that certain smaller power plants are appropriately shut down and replaced by larger and more efficient power plants. The purpose of such rules and regulations is in accordance with China's policy to achieve energy conservation and emissions reductions. China Power International Holdings Ltd., our joint venture partner in Wuhu IV, intended to construct a 2x600 MW coal-fired power plant. According to this policy, and for the ratification, Wuhu V needs to obtain the corresponding closing and shut-down capacity. After consultation among all shareholders of Wuhu IV, the shareholders, including AES, agreed to transfer their respective shares to the owner of Wuhu V and to shut down Wuhu IV. The consideration for the sale of our 25% share in Wuhu IV is RMB 50 million ($7.6 million). The deal achieved financial closing in March 2011. Also per such policy, AES sold our 71% interest in Aixi JV (51

MW coal-fired with CFB boiler) to our local Chinese party at a price of RMB 5.5 million and such transaction financially closed in June 2011.

On July 20, 2009, NDRC issued the "Circular on Refining the Policy for On-Grid Pricing of Wind Power" ("NDRC Price 2009 No. 1906"), which introduces a benchmark system for on-grid tariffs for wind power replacing the existing public bidding and concession model for wind projects. The circular provides that on-grid tariffs for onshore wind power projects approved from August 1, 2009, onward are fixed using a centrally controlled price determination mechanism, while on-grid tariffs for offshore wind projects will be determined separately. Under the circular, China's onshore area is divided into four different types of wind-power resource regions, and different prices are set for each of these regions ranging from 0.51 yuan/kWh (US cent 7.5/kWh) for wind power in regions with the best wind resources, such as Inner Mongolia, to 0.61 yuan/kWh (US cent 8.9/kWh) for regions with the worst wind resources. According to NDRC, the legislation's intent is to standardize the wind power price regulation and promote healthy and sustainable development of the wind-power industry. Currently, we do not expect that this newly issued circular will have a material adverse impact on our wind power businesses in China.

India

Structure of Electricity Market. Pursuant to electricity reforms by the Government of India, including enactment of the Electricity Act of India ("EAI"), the electricity market in India is moving toward a multi-buyer, multi-seller system as opposed to the past structure which permitted a single buyer to purchase power from power generators. This legal and regulatory framework provides flexibility in granting electricity regulatory commissions freedom in determining tariffs as well as encouraging competition in the electricity market, albeit with regulatory intervention. Transmission, distribution and trade of electricity remain regulated activities which require licenses from an electricity regulatory commission, unless exempted. Through the new EAI, generation of electricity has been de-licensed to invite more private participation. The Central Government, through the Ministry of Power, is involved in the power sector planning, policy formulation and appointment of central regulators. State governments also have powers to appoint or remove members of the State Regulatory Commissions, in addition to formulation of policy guidelines applicable to state power sector entities. The state governments set up and notify the state load dispatch center, which controls the physical operation of the grid constituents. Under the EAI, the state governments are required to unbundle the State Electricity Boards into separate generation, distribution and transmission companies.

Principal Regulators. India's power sector is regulated by a two-level regulatory system: at the national level, the Central Electricity Regulatory Commission ("CERC"); and at the state level, the State Electricity Regulatory Commissions ("SERC") (together the "Regulatory Commissions"). CERC regulates tariffs of generating stations owned by the central government, or those involved in generating in more than one state, and regulating interstate transmission of electricity. SERC regulates intra-state transmission and supply of electricity within each state. While discharging functions under the EAI, regulatory commissions are guided by the National Electricity Policy, the Tariff Policy and the National Electricity Plan and directions on any policy involving public interest issued by the Central Government or state government from time to time. Regulatory Commissions are quasi-judicial authorities entrusted with various functions including determining tariffs, granting licensees and settling disputes between the generating companies and the licensees, and between licensees. An Appellate Tribunal has been set up for appeal against orders of Regulatory Commissions. The Appellate Tribunal has quasi-judicial powers to summon, enforce attendance, require discovery, receive evidence and review decisions. The orders of the Appellate Tribunal are executable as decrees of a civil court and can be challenged in the Supreme Court.

Principal Regulations. In 2003, the government of India enacted the EAI to establish a framework for a multi-seller/multi-buyer model for the electricity industry, introducing significant changes to India's electricity sector. The EAI is a central unified legislation relating to generation, transmission, distribution, trading and use of electricity that replaced multiple legislations. Pursuant to the EAI, the government of India ratified the

National Electricity Policy in 2005 and the National Tariff Policy in 2006. The policies established deadlines to implement different provisions of the EAI. However, the pace of actual implementation of the reform process is contingent on the respective state governments and SERCs, as electricity is a "concurrent" subject in India's constitution which has both central and state jurisdictions. There is no license required to set up generation plants under the EAI (except hydroelectric power plants), and generators are allowed to sell to state distribution utilities, traders and open-access consumers. The access to consumers is subject to regulatory provisions on transmission corridor availability and payment of cross-subsidy surcharge.

The Central Government ratified the National Electricity Policy in 2005, which includes the following objectives: access to electricity for all households; availability of power demand to be met by 2012; energy and peaking shortages to be overcome and adequate spinning reserve to be available; supply of reliable and quality power of specified standards, in an efficient, manner and at reasonable rates; per capita availability of electricity to be increased to more than 1,000 units by 2012; financial turnaround and the commercial viability of electricity sector; and the protection of consumers' interests. The "Policy for Setting up of Mega Power Projects" was ratified by the Ministry of Power in 1995 and has been revised from time to time. Conditions required to be fulfilled by a developer for the grant of Mega Power Project status include a thermal power plant with a capacity of 700 MW or more located in the States of Jammu & Kashmir, the northeastern states of India; a thermal power plant of a capacity of 1,000 MW or more located in States other than those specified above; a hydroelectricity power plant of a capacity of 350 MW or more located in the States of Jammu & Kashmir, the northeastern states of India; or a hydroelectricity power plant of a capacity of 500 MW or more located in states other than those specified above. Mega Power Projects would be required to secure long-term PPAs with distribution companies in accordance with the National Electricity Policy 2005 and the National Tariff Policy 2006, as amended from time to time. Fiscal concessions available to the Mega Power Projects include the import of capital equipment free of customs duty and export benefits are available to domestic bidders for projects under both public and private sectors after meeting certain requirements. Capital goods required for setting up any Mega Power Project qualify for the above fiscal benefits after it is certified that: (i) the power-purchasing states have granted to the Regulatory Commissions full powers to fix tariffs; (ii) the power-purchasing states undertake, in principle, to privatize distribution in all cities in that state which has a population of more than one million, within a period to be fixed by the Ministry of Power; and (iii) the income tax holiday regime as per Section 80-IA of the Income Tax Act, 1961 is also available.

The EAI specifies trading in electricity as a distinct and licensed activity. The license for electricity trading is required to be obtained from the relevant regulatory commission. In 2009, CERC issued regulations for the grant of trading licenses to regulate the interstate trading of electricity. Trading license regulations set out qualifications for the grant of the license including technical and professional qualifications and net worth requirements. Licensees are subject to conditions specifying, among other things, the extent of trading margin, maintenance of records and a requirement to pay a license fee, as specified by CERC. The State Regulatory Commissions have the right to fix a ceiling on trading margins in intrastate trading. Two power exchanges have received licenses from CERC and have started operations. The volume of power trading on the power exchanges is growing but is low as the bulk of power is still traded through long-term bilateral contracts.

Environmental Regulations. Compliance with relevant environmental laws is the responsibility of the occupier or operator of subject facilities. Principal regulations include the "Environment (Protection) Act, 1986" ("EPAct"), an umbrella law under which environmental protection laws are promulgated. The EPAct vests the Government of India with the power to take measures it deems necessary for protecting and improving the quality of the environment and preventing and controlling environmental pollution. This includes rules for the quality of the environment, standards for emission or discharge of environmental pollutants from various sources and inspection of any premises, plant, equipment, machinery, and materials likely to cause pollution. Penalties for violation of the EPAct include fines or imprisonment. "Environment Impact Assessment Notification S.O. 1533(E), 2006" issued under the EPAct and the Environment (Protection) Rules, 1986, mandate prior approval by the Ministry of Environment & Forests or State Environment Impact Assessment Authority for establishing a new project or expansion or modernization of existing projects. Projects that require preparation of an environment impact assessment report involve public consultation and hearings. Pursuant thereto, the appropriate authority makes an appraisal of the project after a final environment impact assessment report is submitted addressing the questions raised in the public consultation process. The environmental clearance process is comprehensive, involving assessment of pollution indices, impact on wildlife and biodiversity, and socio-cultural impact and impact on surface and ground water conditions. "The Water (Prevention and Control of Pollution) Cess Act, 1977" (the "Water Cess Act") mandates levy and collection of a tax on water consumed by industries calculated on the basis of the amount of water consumed for any of the purposes specified under the Water Cess Act. "The Air (Prevention and Control of Pollution) Act, 1981" (the "Air Act") requires an industrial plant to obtain consent of the State Pollution Control Board ("Board"). Similarly, "The Water (Prevention and Control of Pollution) Act, *1974*" (the "Water Act") provides provisions for making an application to the Board for establishing an industry which may cause effluent discharge into water bodies. The Board may impose conditions relating to pollution control equipment to be installed at the facilities. Industrial plants in any air pollution control area are not permitted to discharge emissions/air pollutants in excess of the standards set by the Board. Under the Air Act and the Water Act, the Central Pollution Control Board has powers to specify standards for quality of air, while State Boards have powers to inspect any control equipment, industrial plant or manufacturing process.

Material Regulatory Actions. The Electricity Regulatory Commission ("ERC") is empowered to determine tariffs for supply of electricity by a generating company to a distribution licensee, transmission of electricity, wheeling of electricity and retail sale of electricity. In case of a shortage of supply of electricity, the ERC may fix the minimum and maximum tariff ceiling for sale or purchase of electricity for a period not exceeding one year to ensure reasonable prices of electricity. While determining tariffs, the ERC follows principles and methodologies specified by the CERC for determination of tariffs, including the principle that generation, transmission, distribution and supply of electricity should be conducted on commercial principles and takes into account factors which encourage competition, efficiency and economical use of resources.

The EAI provides that the ERC will adopt such tariffs determined through a transparent process of bidding in accordance with guidelines issued by the Central Government. The Central Government, through the Ministry of Power, has issued guidelines for competitive bidding and draft documentation (Standard PPAs) for competitively bid projects. Utilities have to obtain approval from regulatory commissions for the quantum of electricity to be procured competitively and for any deviation in the standard documents before initiating the bidding process. The determination of tariffs for a power project depends on the mode of participation in the project. Tariffs may be determined in two ways: (i) based on tariff principles prescribed by CERC, i.e., cost-plus basis consisting of a capacity charge, an energy charge, an unscheduled interchange charge and incentive payments; or (ii) a competitive bidding process where the tariff is purely market based.

The ERC is required to adopt a bid-based tariff, although the "Guidelines for Determination of Tariff by Bidding Process for Procurement of Power by Distribution Licensees, 2005" ("Bidding Guidelines") permit the bidding authority to accept or reject all price bids received. The Bidding Guidelines recommend bid evaluation on the basis of levelized tariff and include two types of bids: Case I bids, where the location, technology and fuel is not specified by the procurers, i.e., the generating company has the freedom to choose the site, fuel and technology for the power plant; and Case II bids, where the projects are location-specific and fuel-specific. Tariff rates for procurement of electricity by distribution licensees can be for long-term procurement of electricity for a period of seven years and above; or medium-term procurement for a period of up to seven years but exceeding one year. For long-term procurement under tariff bidding guidelines, a two-stage process is adopted for the Case-II bid process including a request for qualification ("RFQ") and request for proposal ("RFP") and a single stage process is allowed to be adopted for Case-I bid process combining the RFQ and RFP process. The Case-I bidding process is a "PPA auction" where the procurer seeks to source power competitively, irrespective of the technology or fuel type adopted by the supplier (traders and generators). The Case-II bidding process is a "project auction" where the state or federal government seeks to source a developer through competitive tariff bid by providing basic requirements like land, fuel, water and other permits. The procurer may adopt a single-stage tender process for medium-term procurement, combining the RFQ and RFP processes. Under this route, IPPs can bid at two parameters, i.e., the fixed or capacity charge or the variable or energy charge, which constitute the fuel cost for the electricity generated. Both the capacity and energy parameters can be bid with non-scalable components. The escalation factors are notified by CERC from time to time. Bidding guidelines include a two-step process—pre-qualification and final bid. Bidders are required to submit a technical and financial bid at the RFP stage. Power purchase and distribution licenses are increasing through the competitive bid route. The Tariff Policy requires all procurement of power after January 6, 2006 (except for PPAs approved or submitted for approval before January 6, 2006 or projects which have obtained financing prior to January 6, 2006) by distribution licensees to be through competitive bidding. However a subsequent notification by the Ministry of Power has extended this deadline up to January 6, 2011. Some state regulators have ratified the purchase of power under memorandums of understanding, on the ground that the tariff policy discussed above is merely indicative and not binding.

Philippines

Structure of Electricity Market. From a vertically integrated industry, the Philippines has unbundled its power sector into generation, transmission, distribution and supply. The enabling law for this restructuring is Republic Act No. 9136, otherwise known as the Electric Power Industry Reform Act of 2001 ("EPIRA"). The EPIRA primarily aims to increase private sector participation in the power sector and to privatize the Government's generation and transmission assets. Generation and supply are open and competitive sectors, while transmission and distribution are regulated sectors. Sale of power is done primarily thorough medium-term contracts between generation companies and customers specifying the volume, price and conditions for the sale of energy and capacity. The Energy Regulatory Commission ("ERC") approves the said contracts for supply of energy. Power is also traded in the Wholesale Electricity Spot Market ("WESM") from which at least 10% of the distribution companies or electricity cooperatives power requirement must be sourced.

A market optimization model determines the price and dispatch by processing the bids from trading participants and the system condition from the system operator. The market operator then comes out with a schedule of both price and energy which maximizes economic gains for participants subject to certain constraints. The dispatch schedule is then coordinated with the system operator for implementation. The market is operating under a gross pool, net settlement system, whereby each generator submits energy offers regardless of their contracted energy. However, the generator should declare their contracted quantities, since the market will not include contracted energy in its settlement.

New contracts assigned by distribution companies for consumption after expiration are awarded to generation companies either through the lowest supply price offered in public bid processes or through a negotiated contract. The ERC then approves the said contract benchmarked against, among others, the prices of the best new entrant generation company.

AES Masinloc has secured a seven year Power Supply Agreement ("PSA") contract with MERALCO, with a three-year option to extend, MERALCO is the largest distribution company in the Philippines. The contract with MERALCO requires approval by the ERC.

The existing supply contract with MERALCO, under the NPC Transition Supply Contract, was extended for another year and will cease by December 25, 2012. The extension will automatically terminate once the PSA is approved by the ERC or three months after commencement of the Retail Competition and Open Access expected by fourth quarter of 2012.

Except one, the other supply contracts with the Electric Cooperatives were renegotiated and extended for another ten years. The Contract for Supply of Electric Energy ("CSEE") extensions was already filed with the ERC for approval.

Principal Regulators. The ERC, created under the EPIRA, is mandated to protect long-term consumer interest in terms of quality, reliability and reasonable pricing of sustainable supply of electricity. It is a quasi-judicial body that promulgates and enforces rules, regulations, guidelines and policies. The Department of

Energy is mandated to prepare, integrate, coordinate, supervise and control all plans, programs, projects and activities of the government relative to energy exploration, development, utilization, distribution and conservation. The DOE endorses new or existing generators. The Department of Environment and Natural Resources administers the system for evaluating the environmental impact of new or existing generating plants.

Principal Regulations. The distinct electricity sector activities are regulated by the EPIRA. Sector activities are also governed by the corresponding technical regulations and standards, namely, the Philippine Grid Code, Philippine Distribution Code, Open Access Transmission Service Rules, WESM Rules, and Distribution System Open Access Rules ("DSOAR").The keystones of the electricity regulation are: (i) performance based on revenue cap and non-discriminatory access to transmission lines; (ii) a contract-based supply and spot electricity trading for generation; (iii) performance based on maximum average price and non-discriminatory access for DUs and ECs under the performance base rate regime; and (iv) electricity supply by distribution companies in their respective franchise areas.

Section 31 of EPIRA establishes the Retail Competition and Open Access ("RC&OA") under which Retail Electricity Suppliers, who are duly licensed by the ERC, may supply directly to Contestable Customers (end-users with an average demand of at least 1,000 kW) with DUs and ECs providing non-discriminatory wires services. ERC concluded that the pre-conditions for RC&OA had already been satisfied and declared December 26, 2011 as the commencement date under ERC Resolution No. 10 on June 6, 2011. MERALCO, Private Electric Power Operators Association and Philippine Rural Electric Cooperatives Association, Inc., petitioned the ERC to postpone the RC&OA implementation because systems required for RC&OA such as B2B and Accounting, Billing and Settlement will take a longer time to complete. As a result, ERC deferred the implementation of the RC&OA. The new target commencement date is the fourth quarter of 2012.

Environmental Regulations. The Renewable Energy Act of 2008 ("R.A. 9513") was enacted in December 2008 to promote non-conventional renewable energy sources, such as solar, wind, small hydroelectric and biomass energies. The law requires electric power participants to initially source 10% of their supply from eligible renewable energy resources. The initial requirement of 10% is preliminary, as the National Renewable Energy Board ("NREB") has not set the final figure. It is unknown at this time if the definition of electric power participant applies to entities that are power producers or to power consumers. If and once the regulations are implemented, our businesses in the Philippines could be adversely impacted by requirements to source a portion of their generation from renewable energy resources to supply its customers' contracts, which could in turn affect our results of operations. Under Section 6 R.A. 9513, consumers are also given a green energy option which provides end-users the option to choose renewable energy sources as their sources of energy.

Water rights are given by the National Water Resources Board under the Department of Environment and Natural Resource for extraction and discharge of water used in the operation of the Masinloc Plant.

Material Regulatory Actions. Final approval of power contracts signed with MERALCO and the Electric Cooperatives is pending and expected by 2012.

Potential or Proposed Regulations. Section 72 of the EPIRA requires a mandated rate reduction from NPC rates. With the assignment of the Transition Supply Contracts to successor generating companies, such as AES Masinloc, NPC's position is that the mandated rate reduction shall be for the account of the successor generating companies. AES Masinloc filed a petition with ERC to initiate rule making and clarify the MRR implementation in light of the ongoing privatization of NPC plants. In its decision, the ERC ruled in favor of AES Masinloc, saying that the EPIRA mandated rate reduction shall be implemented by the successor generating company subject to the execution of a written instrument between NPC and the new generator specifically containing the assumption by the latter of such obligation. The ERC ruled in favor of AES Masinloc since there was no such written instrument. NPC filed a petition for review with the Court asking for a reversal of the said ERC decision. The case is pending with the Court of Appeals. If AES Masinloc loses this matter on appeal, it may be subject to the rate reduction described above, which could have a material impact on its business and our results of operations.

A similar mandated rate reduction case is pending with the ERC. MERALCO alleges that AES Masinloc failed to account for the rate reduction in MERALCO's favor amounting to Php179,611,458.98 ($4.1 million). It is assumed that the ERC will wait for the decision of the first matter described in the preceding paragraph before ruling on the MERALCO case since the latter is particularly dependent on the outcome of the pending petition with the Court of Appeals.

Environmental and Land Use Regulations

Overview. The Company faces certain risks and uncertainties related to numerous 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, mercury and other hazardous air pollutants. 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 United States 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*" in this Form 10-K.

Many of the countries in which the Company does business also have laws and regulations relating to the siting, construction, permitting, ownership, operation, modification, repair and decommissioning of, and power sales from electric power generation or distribution assets. In addition, international projects funded by the International Finance Corporation, the private sector lending arm of the World Bank, or many other international lenders are subject to World Bank environmental standards or similar standards, which tend to be more stringent than local country standards. The Company often has used advanced environmental technologies in order to minimize environmental impacts, including circulating fluidized bed ("CFB") coal technologies, flue gas desulphurization technologies, selective catalytic reduction technologies and advanced gas turbines.

Environmental laws and regulations affecting electric power generation and distribution facilities are complex, change frequently and have become more stringent over time. The Company has incurred and will continue to incur capital costs and other expenditures to comply with these environmental laws and regulations. See Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations—*Capital Expenditures* in this Form 10-K for more detail. The Company and its subsidiaries may be required to make significant capital or other expenditures to comply with these regulations. There can be no assurance that the businesses operated by the subsidiaries of the Company will be able to recover any of these compliance costs from their counterparties or customers such that the Company's consolidated results of operations, financial condition and cash flows would not be materially affected.

Various licenses, permits and approvals are required for our operations. Failure to comply with permits or approvals, or with environmental laws, can result in fines, penalties, capital expenditures, interruptions or changes to our operations. Certain subsidiaries of the Company are subject to litigation or regulatory action relating to environmental permits or approvals. See Item 3.—Legal Proceedings in this Form 10-K for more detail with respect to environmental litigation and regulatory action, including a Notice of Violation ("NOV") issued by the United States Environmental Protection Agency against IPL concerning new source review and prevention of significant deterioration issues under the United States Clean Air Act.

Greenhouse Gas Laws, Protocols and Regulations. In 2011, the Company's subsidiaries operated electric power generation businesses which had total approximate direct CO_2 emissions of 74 million metric tonnes, approximately 37.5 million metric tonnes of which were emitted in the United States (both figures ownership adjusted). The Company uses CO_2 emission estimation methodologies supported by the "The Greenhouse Gas Protocol" reporting standard on GHG emissions. For existing power generation plants, CO_2 emissions are either obtained directly from plant continuous emission monitoring systems or calculated from actual fuel heat inputs and fuel type CO_2 emission factors. The following is an overview of both the regulations and laws that currently apply to our businesses and those that may be imposed over the next few years. Such regulations and laws could have a material effect on the electric power generation and distribution businesses of the Company's subsidiaries and on the Company's consolidated results of operations, financial condition and cash flows.

International

On February 16, 2005, the Kyoto Protocol became effective. The Kyoto Protocol requires the industrialized countries that have ratified it to significantly reduce their GHG emissions, including CO_2. The vast majority of developing countries which have ratified the Kyoto Protocol have no GHG reduction requirements, including many of the countries in which the Company's subsidiaries operate. Of the 27 countries in which the Company's subsidiaries currently operate, all but one—the United States (including Puerto Rico)—have ratified the Kyoto Protocol. To date, compliance with the Kyoto Protocol and the European Union Emissions Trading System has not had a material effect on the Company's consolidated results of operations, financial condition and cash flows. The first commitment period under the Kyoto Protocol is currently expected to expire at the end of 2012. In December 2011, the annual United Nations conference of the parties to the Kyoto Protocol ("COP 17") was held in Durban, South Africa to focus on establishing a second commitment period under the Kyoto Protocol or an international agreement or framework to succeed the Kyoto Protocol. COP 17 did not result in any legally binding second commitment period or successor agreement to the Kyoto Protocol, but most of the original signatories to the Kyoto Protocol agreed to extend their GHG emissions reduction commitments under the Kyoto Protocol by at least five years and countries agreed to continue to work toward a successor international agreement on GHG emissions reductions by 2015. At present, the Company cannot predict whether compliance with any successor commitment period under the Kyoto Protocol or any successor agreements will have a material effect on the Company's consolidated results of operations, financial condition and cash flows in future periods.

In July 2003, the European Community "Directive 2003/87/EC on Greenhouse Gas Emission Allowance Trading" was created, which requires Member States to limit emissions of CO_2 from large industrial sources within their countries. During the first and second trading periods of EU ETS, which commenced in January 2005 and terminates at the end of 2012, Member States were required to implement EC-approved national allocation plans ("NAPs"). Under the NAPs, Member States were responsible for allocating limited CO_2 allowances within their borders through 2012. Directive 2003/87/EC did not dictate how these allocations were to be made, and the NAPs that were submitted varied in their allocation methodologies. The current NAPs in each Member State will apply until the end of 2012.

Pursuant to "Directive 2009/29/EC amending European Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading scheme of the Community," (the "2009 Amending Directive"), the European Union has announced that it intends to keep the EU ETS in place through the third trading period, which ends in 2020, even if the Kyoto Protocol is not replaced by another agreement. NAPs were required during the first and second trading periods. However, for the third trading period, which begins in 2013, there will no longer be any national allocation plans. Instead, the allocations will be determined directly by the EU.

The Company's subsidiaries operate seven electric power generation facilities within five member states which have adopted NAPs to implement Directive 2003/87/EC. During the first and second trading periods, achieving and maintaining compliance with the NAPs did not have a material impact on consolidated operations or results of the Company.

The risk and benefit associated with achieving compliance with applicable NAPs at several facilities of the Company's subsidiaries are not the responsibility of the Company's subsidiaries, as they are subject to contractual provisions that transfer the costs associated with compliance to contract counterparties. In connection with any potential dispute that might arise with contract counterparties over these provisions, there can be no assurance that the Company and/or the relevant subsidiary would prevail, or that the failure to prevail in any such dispute will not have a material effect on the Company and its financial condition or consolidated results of operations. Certain of the Company's subsidiaries will bear some or all of the risk and benefit associated with compliance with applicable NAPs at certain facilities.

The 2009 Amending Directive was adopted by the EU in April 2009 as part of the EU's "Climate Change Package," which also included a Carbon Capture & Storage Directive and a revised Renewables Directive. The 2009 Amending Directive provides for the third trading period of the EU ETS, which will apply from the beginning of 2013 until 2020. The key characteristics of the third trading period relevant to the Company are as follows:

- The EU is aiming to reduce EU-wide CO_2 emissions by 21% from 2005 levels by 2020.
- A single, EU-wide cap on annual CO_2 allowances will be imposed by the European Commission, rather than Member States. This cap will decrease annually.
- Significantly fewer free CO_2 allowances will be allocated than during the first and second trading periods, with an increasing number being made available for purchase by auction (50% of all allowances will be auctioned in 2013, compared to 3% in the second trading period).
- Free allocations will be set using a benchmark based on the most efficient installations for each type of product, with very limited allocations for electricity production. In 2013, each installation will receive free allowances equivalent to 80 percent of the benchmark, with the proportion decreasing each year, to 0% by 2027.
- NAPs will be replaced by National Implementing Measures ("NIMs"), which set out the levels of free allocation of allowances to installations in accordance with harmonized EU rules. Member States are required to submit proposed NIMs to the EU, and they will be assessed and approved during 2012.

In addition to the 2009 Amending Directive for the EU ETS, the Renewables Directive was also adopted by the EU in April 2009, and will enter into force in each individual EU Member State upon the adoption by each country of implementing legislation or regulations. The key requirement of the Renewables Directive is a minimum target of 20 percent of all energy generation in the EU to be from renewable sources by 2020.

AES generation businesses in each Member State will be required to comply with the relevant measures taken to implement the directives, including each of the relevant NIMs.

Even though the 2009 Amending Directive means that the EU ETS will remain in place even if the Kyoto Protocol expires at the end of 2012 without any successor commitment period or agreement or other international commitment on GHG emissions reductions, there remains significant uncertainty with respect to the third trading period and the implementation of NIMs post-2012. Although many Member States have submitted draft NIMs to the EU for approval, these NIMs could undergo changes and there is no certainty as to their final form. At this time, the Company cannot determine whether achieving and maintaining compliance with the EU allocation plan for the third trading period, to which its subsidiaries are subject, will have a material impact on its consolidated operations or financial results.

Countries in Latin America, Asia and Africa in which subsidiaries of the Company operate may also choose to adopt regulations that directly or indirectly regulate GHG emissions from power plants. For a discussion of regulations in individual countries where our subsidiaries operate, see Item 1. Business—Regulatory Matters in this Form 10-K. Although the Company does not currently believe that the laws and regulations pertaining to GHG emissions that have been adopted to date in countries in Latin America, Asia and Africa in which subsidiaries of the Company operate will have a material impact on the Company, the Company cannot predict with any certainty if future laws and regulations in these countries regarding CO_2 emissions will have a material effect on the Company's consolidated financial condition or results of operations.

United States—Federal Legislation and Regulation

Currently, in the United States there is no Federal legislation establishing mandatory GHG emissions reduction programs (including for 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 United States Federal GHG Legislation. Federal legislation passed the United States 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. Although it is unlikely that any legislation pertaining to GHG emissions will be voted on and passed by the U.S. Senate and House of Representatives in 2012, it is uncertain if any such legislation will be voted on and passed by the U.S. Congress in subsequent years. If any such legislation is enacted into law, the impact could be material to the Company.

EPA GHG Regulation. The EPA made a finding that GHG emissions from mobile sources represent an "endangerment" to human health and the environment (the "Endangerment Finding") following the Supreme Court's decision in Massachusetts v. EPA, that the EPA has the authority under the CAA to regulate GHG emissions. The EPA then subsequently promulgated regulations governing GHG emissions from automobiles under the CAA ("Motor Vehicle Rule"). The effect of the 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 United States power plants. In particular, since January 2, 2011, owners or operators who plan construction of new stationary sources and/or modifications to existing stationary sources, which would result in increased GHG emissions, are required to obtain prevention of significant deterioration ("PSD") permits prior to commencement of construction. 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 committed to propose GHG emissions standards for EUSGUs by July 26, 2011. The EPA subsequently announced that it was delaying the proposal further, without specifying a deadline for the proposal but has committed to finalize GHG NSPS for EUSGUs by May 26, 2012. The NSPS is expected to establish GHG emission standards for newly constructed and reconstructed EUSGUs. The NSPS also may establish guidelines regarding the best system for achieving further GHG emissions reductions from existing EUSGUs. Based on such guidelines, individual states will be required to develop regulations establishing GHG performance standards for existing EUSGUs within their state. 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 impact on our consolidated financial condition or results of operations.

A consortium of industry petitioners has challenged the Endangerment Finding, Tailoring Rule and the Motor Vehicle Rule in the United States Court of Appeals for the District of Columbia Circuit. These challenges have been consolidated, briefed and set for oral argument on February 28 and 29, 2012. We cannot predict the outcome of this litigation.

United States—State Legislation and Regulation

Regional Greenhouse Gas Initiative. The primary regulation of GHG emissions affecting the United States plants of the Company's subsidiaries has previously 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. Maryland is now the only state currently participating in RGGI in which our subsidiaries have a relevant generating facility. Under RGGI, power plants must acquire one carbon allowance through auction or in the emission trading markets for each ton of CO_2 emitted. We have estimated the costs to the Company of compliance with RGGI could be approximately \$2.8 million for 2012, and this represents a significant reduction in estimated compliance costs from prior years largely due to the deconsolidation of subsidiaries that owned plants in Connecticut and New York and filed for bankruptcy in 2011. The initial three-year compliance period for RGGI expired at the end of 2011. Under the subsequent three-year compliance period (2012 through 2014), the cap on aggregate CO_2 emissions per year for RGGI states is 165 million short tons of CO_2, and the affected states are conducting a program wide review that could result in changes to the 2012 through 2014 compliance period, including a lower emissions cap. While these estimated compliance costs are not material to the Company, changes in the regulations or price of allowances under RGGI could have a material impact on our operations and financial performance.

The Company's Warrior Run business is located in Maryland. In April 2006, the Maryland General Assembly passed the Maryland Healthy Air Act which, among other things, required the State of Maryland to join RGGI. The Maryland Department of Environment ("MDE") adopted regulations that require 100% of the allowances the State receives to be auctioned except for several small allowance set-aside accounts. The MDE regulations include a safety valve to control the economic impact of the CO_2 cap-and-trade program. If the auction closing price reaches \$7, up to 50% of a year's allowances will be reserved for purchase by electric power generation facilities located within Maryland at \$7 per allowance, regardless of auction prices. Warrior Run continues to secure its allowance requirements through the RGGI allowance auction.

In 2011, of the approximately 37.5 million metric tonnes of CO_2 emitted in the United States by the businesses operated by our subsidiaries (ownership adjusted), approximately 8.3 million metric tonnes were emitted in states participating in RGGI. Over the past three years, such emissions have averaged approximately 9.8 million metric tonnes. The reduction in aggregate emissions by subsidiaries operating in RGGI states from prior years is largely due to lower dispatch at AES Thames and Eastern Energy. While CO_2 emissions from businesses operated by subsidiaries of the Company are calculated globally in metric tonnes, RGGI allowances are denominated in short tons. (1 metric tonne equals 2,200 pounds and 1 short ton equals 2,000 pounds.) For forecasting purposes, the Company has modeled the impact of CO_2 compliance based on a three-year average of CO_2 emissions for its businesses that are subject to RGGI and that may not be able to pass through compliance costs. The model includes a conversion from metric tonnes to short tons, as well as the impact of some market recovery by merchant plants and contractual and regulatory provisions. The model also utilizes a price of $1.89 per allowance under RGGI. The source of this allowance price estimate was the clearing price in the most recent RGGI allowance auction held in December 2011. Based on these assumptions, the Company estimates that the RGGI compliance costs could be approximately $2.8 million for 2012. Given the fact that the assumptions utilized in the model may prove to be incorrect, there is a risk that our actual compliance costs under RGGI will differ from our estimates and that our model could underestimate our costs of compliance.

California. The Company's Southland business is located in California. On September 27, 2006, the Governor of California signed the Global Warming Solutions Act of 2006, also called Assembly Bill 32 ("A.B. 32"). A.B. 32 directs the California Air Resources Board ("CARB") to promulgate regulations that will require the reduction of CO_2 and other GHG emissions to 1990 levels by 2020. On October 20, 2011, CARB approved a set of regulations to implement a state-wide cap-and-trade program to regulate GHG emissions. The first compliance period is scheduled to begin on January 1, 2013, and initially covers emissions from electricity generating facilities, large industrial sources with annual emissions greater than 25,000 tons, and imported electricity. Emitters will be required to hold enough allowances or offsets to match their GHG emissions, and can comply by reducing their emissions or by purchasing tradable allowances from other emitters or at state-run auctions. Companies that reduce their emissions below the allowances they hold have the opportunity to sell unused allowances. Initially, retail utilities will be issued free allowances and merchant facilities will be required to bid for allowances at auctions. There is a floor price of $10 for all allowances purchased at auctions. The percentage of free allowances will decline in Phase II and will further decline when Phase III begins in 2018. The program will continue through 2020. Offset credits may be issued for certain verified reductions of GHG emissions or sequestration projects not required by these regulations. The offset credits may be used to satisfy up to eight percent of an entity's compliance obligation or they may be sold. CARB will continue to refine certain elements of the cap-and-trade program through further rulemakings over the next year via CARB's "15 day notice" procedure, whereby changes to adopted regulations are recommended by CARB staff and subject to a 15-day public comment period.

California is also a member of the Western Climate Initiative ("WCI"), an organization that includes California as well as four Canadian provinces (British Columbia, Manitoba, Ontario, and Quebec). The WCI has developed a separate program to reduce GHG emissions through a cap-and-trade program that also affects California. As a member of WCI, California has agreed to cut GHG emissions to 15% below 2005 levels by 2020. WCI, Inc., a non-profit corporation, was incorporated in November 2011 to provide administrative and technical services to support the implementation of state and provincial greenhouse gas emissions trading programs and in 2012 it intends to focus on harmonizing the cap-and-trade programs between California and Quebec, the only two WCI members to have adopted cap-and-trade programs to date. WCI, Inc. expects to have two allowance auctions held by the end of 2012. The Company believes that any compliance costs arising from A.B. 32 and the WCI cap-and-trade program for the thermal power plants of its subsidiaries operating in California will be borne by the power offtaker under the terms of existing tolling agreements with the offtaker and under the terms of the programs. However, after the expiration of such tolling agreements, if the Company's subsidiaries were to sell power on a merchant basis then such compliance costs would likely be borne by the subsidiaries. Also, if following the expiration of such tolling agreements the Company's subsidiaries entered into new, long-term power purchase agreements that did not provide for compliance costs to be borne by the offtakers then the compliance costs would likely be borne by the Company's subsidiaries.

Midwestern Greenhouse Gas Reduction Accord (MGGRA). The Company owns the utility IPL, located in Indiana, and the utility DP&L, located in Ohio. On November 15, 2007, six Midwestern state governors and the premier of Manitoba signed the Midwestern Greenhouse Gas Reduction Accord ("MGGRA"), committing the participating states and province to reduce GHG emissions through the implementation of a cap-and-trade program. Three states (including Indiana and Ohio) and the province of Ontario have signed as observers. In May of 2010, the MGGRA Advisory Group finalized a set of recommendations for the establishment of targets for emissions reductions in the region and for the design of a regional cap-and-trade program. These include a recommended reduction in GHG emissions of 20% below 2005 emission levels by 2025. The recommendations are from the advisory group only, and have not been endorsed or approved by individual governors, including the Governors of Indiana and Ohio. Though MGGRA has not been formally suspended, participating states are no longer pursuing it. If Indiana or Ohio were to implement the recommended reduction targets, the impact on the Company's consolidated results of operations, financial condition, and cash flows could be material.

Hawaii. The Company owns a power generation facility in Hawaii. On June 30, 2007, the Governor of Hawaii signed Act 234 which sets a goal of reducing GHG emissions to at or below 1990 levels by January 1, 2020. Act 234 also established the Greenhouse Gas Emissions Reduction Task Force, which is tasked with developing measures to meet Hawaii's GHG emissions reduction goal. The Task Force filed a report to the Hawaii Legislature on December 30, 2009, strongly supporting the Hawaii Clean Energy Initiative, which calls for additional renewable energy development, increased energy efficiency, and incorporates already-enacted renewable portfolio standards. The Task Force also evaluated other mechanisms and concluded that a state-level cap-and-trade program is inappropriate due to the small size of Hawaii's economy.

At this time, other than the estimated impact of CO_2 compliance noted above for certain of its businesses that are subject to RGGI, the Company has not estimated the costs of compliance with other potential United States federal, state or regional CO_2 emissions reduction legislation or initiatives, such as A.B. 32, WCI, MGGRA and potential Hawaii regulations, due to the fact that most of these proposals are not being actively pursued or are in the early stages of development and any final regulations or laws, if adopted, could vary drastically from current proposals, or, in the case of A.B. 32, due to the fact that we anticipate such costs to be passed through to our offtakers under the terms of existing tolling agreements. Although complete specific implementation measures for any federal regulations, WCI, MGGRA and the Hawaiian regulations have yet to be finalized, if these GHG-related initiatives are finalized they may affect a number of the Company's United States subsidiaries unless they are preempted by federal GHG legislation. Any federal, state or regional legislation or regulations adopted in the United States that would require the reduction of GHG emissions could have a material effect on the Company's consolidated results of operations, financial condition and cash flows.

The possible impact of any future federal GHG legislation or regulations or any regional or state proposal will depend on various factors, including but not limited to:

- the geographic scope of legislation and/or regulation (e.g., federal, regional, state), which entities are subject to the legislation and/or regulation (e.g., electricity generators, load-serving entities, electricity deliverers, etc.), the enactment date of the legislation and/or regulation and the compliance deadlines set forth therein;
- the level of reductions of CO_2 being sought by the regulation and/or legislation (e.g., 10%, 20%, 50%, etc.) and the year selected as a baseline for determining the amount or percentage of mandated CO_2 reduction (e.g., 10% reduction from 1990 CO_2 emission levels, 20% reduction from 2000 CO_2 emission levels, etc.);
- the legislative and/or regulatory structure (e.g., a CO_2 cap-and-trade program, a carbon tax, CO_2 emission limits, etc.);
- in any cap-and-trade program, the mechanism used to determine the price of emission allowances or offsets to be auctioned by designated governmental authorities or representatives;
- the price of offsets and emission allowances in the secondary market, including any price floors or price caps on the costs of offsets and emission allowances;
- the operation of and emissions from regulated units;
- the permissibility of using offsets to meet reduction requirements and the requirements of such offsets (e.g., type of offset projects allowed, the amount of offsets that can be used for compliance purposes,

any geographic limitations regarding the origin or location of creditable offset projects), as well as the methods required to determine whether the offsets have resulted in reductions in GHG emissions and that those reductions are permanent (i.e., the verification method);

- whether the use of proceeds of any auction conducted by responsible governmental authorities is reinvested in developing new energy technologies, is used to offset any cost impact on certain energy consumers or is used to address issues unrelated to power;
- how the price of electricity is determined at the affected businesses, including whether the price includes any costs resulting from any new CO_2 legislation and the potential to transfer compliance costs pursuant to legislation, market or contract, to other parties;
- any impact on fuel demand and volatility that may affect the market clearing price for power;
- the effects of any legislation or regulation on the operation of power generation facilities that may in turn affect reliability;
- the availability and cost of carbon control technology;
- the extent to which existing contractual arrangements transfer compliance costs to power offtakers or other contractual counterparties of our subsidiaries;
- whether legislation regulating GHG emissions will preclude the EPA from regulating GHG emissions under the Clean Air Act or preempt private nuisance suits or other litigation by third parties; and
- any opportunities to change the use of fuel at the generation facilities of our subsidiaries or opportunities to increase efficiency.

Other United States Air Emissions Regulations and Legislation. In the United States the CAA and various state laws and regulations regulate emissions of air pollutants, including SO_2, NO_X, particulate matter ("PM"), mercury and other hazardous air pollutants ("HAPs"). The applicable rules and the steps taken by the Company to comply with the rules are discussed in further detail below.

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 contemplated two implementation phases. The first phase was to begin in 2009 and 2010 for NO_X and SO_2, respectively. A second phase with additional allowance surrender obligations for both air emissions was to begin in 2015. To implement the required emission reductions for this rule, the states were to establish emission allowance based "cap-and-trade" programs. 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 7, 2011, the EPA issued a final rule titled "Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States," which is now referred to as the Cross-State Air Pollution Rule ("CSAPR"). Starting in 2012, the CSAPR requires significant reductions in SO_2 and NO_X emissions from covered sources, such as power plants, in many states in which subsidiaries of the Company operate. Once fully implemented in 2014, the rule requires additional SO_2 emission reductions of 73% and additional NO_X reductions of 54% from 2005 levels. The CSAPR will be implemented, in part, through a market-based program under which compliance may be achievable through the acquisition and use of new emissions allowances that the EPA will create. The CSAPR contemplates limited interstate and intra-state trading of emissions allowances by covered sources. Initially, at least through 2012, the EPA will issue emissions allowances to affected power plants based on state emissions budgets established by the EPA under the CSAPR. The future availability of and cost to purchase allowances to meet the emission reduction requirements is uncertain at this time. The CSAPR was published in the Federal Register on August 8, 2011, and on October 6, 2011, the EPA proposed some technical revisions to the CSAPR, including allowing for additional allowances for certain states.

Many states, utilities and other affected parties filed petitions for review, challenging the CSAPR before the U.S. Court of Appeals for the District of Columbia. A large subset of the Petitioners also sought a stay of the CSAPR. On December 30, 2011, the court granted a temporary stay of the CSAPR and directed the EPA to continue administering CAIR. The court set forth a schedule of briefings to allow for the case to be heard by April of 2012. We cannot predict the outcome of this litigation, including whether the stay will be lifted and whether the CSAPR will be ultimately implemented in its current form or a modified form. To comply with the CSAPR as currently proposed, 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 Company. Additionally, compliance with the CSAPR could require the purchase of newly issued allowances, the switch to higher priced, lower sulfur coal, and changes in the dispatch of our facilities or the retirement of existing generating units. While the capital costs, other expenditures or operational restrictions necessary to comply with the CSAPR cannot be specified at this time, and the ultimate outcome of litigation pertaining to the CSAPR is uncertain, the Company anticipates that the CSAPR may have a material impact on the Company's business, financial condition and results of operations.

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. In connection with such rule, the CAA requires the EPA to establish Maximum Achievable Control Technology ("MACT"). MACT is defined as the emission limitation achieved by the "best performing 12%" of sources in the source category. Pursuant to Section 112 of the CAA, the EPA promulgated a final rule on December 16, 2011, called the Mercury Air Toxics Standards ("MATS" or the "Utility MACT") establishing national emissions standards for hazardous air pollutants ("NESHAP") from coal and oil-fired electric utility steam generating units. These emission standards reflect the EPA's application of Utility MACT standards for each pollutant regulated under the rule. The rule requires all coal-fired power plants to comply with the applicable Utility MACT standards within three years, with the possibility of obtaining an additional year, if needed, to complete the installation of necessary controls. To comply with the rule, many coal-fired power plants may need to install additional control technology to control acid gases, mercury or particulate matter, or they may need to repower with an alternate fuel or retire operations. Most of the Company's United States coal-fired plants operated by the Company's subsidiaries have acid gas scrubbers or comparable control technologies, but there are other improvements to such control technologies that may be needed at some of the Company's plants to assure compliance with the Utility MACT standards. Older coal-fired facilities that do not currently have a SO_2 scrubber installed are particularly at risk. On July 15, 2011, Duke Energy, co-owner with DP&L at the Beckjord Unit 6 facility, a 414 MW power plant, filed their Long-term Forecast Report with the Public Utilities Commission of Ohio ("PUCO"). The report indicated that Duke Energy plans to cease production at the Beckjord Station, including the jointly-owned Unit 6, in December 2014. DP&L is considering options for its Hutchings Station, a six unit power plant with 365MW of total capacity, to comply with the Utility MACT standards, including the possibility of converting two or more of the units to natural gas or retiring some or all of the units. DP&L has not yet made a final decision. The combination of existing and expected environmental regulations, including the Utility MACT, make it likely that IPL will temporarily or permanently retire several of its existing, primarily coal-fired, smaller and older generating units within the next several years. These units are not equipped with the advanced environmental control technologies needed to comply with existing and expected regulations, and collectively make up less than 15% of IPL's net electricity generation over the past five years. IPL is continuing to evaluate options for replacing this generation. IPL is currently reviewing the impact of the new Utility MACT rule and estimates total additional expenditures for IPL related to this rule to be approximately $500 million to $900 million through approximately 2016. IPL would seek recovery of any operating or capital expenditures related to air pollution control technology to reduce regulated air emissions; however, there can be no assurances that IPL would be successful in that regard. The EPA is encouraging state permitting authorities to allow for an additional year to comply with the rule. While the capital costs, other expenditures or operational restrictions necessary to comply with the rule cannot be specified at this time, the Company anticipates that the rule may have a material impact on the Company's business, financial condition and results of operations.

New Source Review

The new source review ("NSR") requirements under the CAA impose certain requirements on major emission sources, such as electric generating stations, if changes are made to the sources that result in a significant increase in air emissions. Certain projects, including power plant modifications, are excluded from these NSR requirements, if they meet the routine maintenance, repair and replacement ("RMRR") exclusion of the CAA. There is ongoing uncertainty, and significant litigation, regarding which projects fall within the RMRR exclusion. The EPA has pursued a coordinated compliance and enforcement strategy to address NSR compliance issues at the nation's coal-fired power plants. The strategy has included both the filing of suits against power plant owners and the issuance of Notices of Violation ("NOVs") to a number of power plant owners alleging NSR violations. See Item 3.—Legal Proceedings in this Form 10-K for more detail with respect to environmental litigation and regulatory action, including a NOV issued by the EPA against IPL concerning NSR and prevention of significant deterioration issues under the United States Clean Air Act.

During the last decade, DP&L's Stuart Station and Hutching Station have received NOVs from the EPA alleging that certain activities undertaken in the past are outside the scope of the RMRR exclusion. Additionally, generation units partially owned by DP&L but operated by other utilities have received such NOVs relating to equipment repairs or replacements alleged to be outside the RMRR exclusion. The NOVs issued to DP&L-operated plants have not been pursued through litigation by the EPA.

If NSR requirements were imposed on any of the power plants owned by subsidiaries of the Company, the results could have a material impact on the Company's business, financial condition and results of operations. In connection with the imposition of any such NSR requirements on our U.S. utilities, DP&L and IPL, the utilities would seek recovery of any operating or capital expenditures related to air pollution control technology to reduce regulated air emissions; however, there can be no assurances that they would be successful in that regard.

Regional Haze Rule

In July 1999, the EPA published the "Regional Haze Rule" to reduce haze and protect visibility in designated federal areas. On June 15, 2005, the EPA proposed amendments to the Regional Haze Rule that, among other things, set guidelines for determining when to require the installation of "best available retrofit technology" ("BART") at older plants. The amendment to the Regional Haze Rule required states to consider the visibility impacts of the haze produced by an individual facility, in addition to other factors, when determining whether that facility must install potentially costly emissions controls. States were required to submit their regional haze state implementation plans ("SIPs") to the EPA by December 2007, but only 13 states met this deadline. The EPA has yet to approve any state's Regional Haze state implementation plan. The statute requires compliance within five years after the EPA approves the relevant SIP, although individual states may impose more stringent compliance schedules. On December 2, 2011, the EPA published a notice that it entered a consent decree with several environmental groups. The consent decree requires the EPA to review and take final action on regional haze requirements for more than 40 states and territories. The EPA had previously determined that any EGU that is subject to the CAIR rule is deemed to meet the BART requirement. On December 30, 2011, the EPA proposed regulatory language that would similarly establish that compliance with the CSAPR would constitute compliance with BART requirements. The EPA will take comments on this proposal until February 25, 2012.

Other International Air Emissions Regulations and Legislation. In Europe, the Company is, and will continue to be, required to reduce air emissions from our facilities to comply with applicable EUC Directives, including Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from large combustion plants (the "LCPD"), which sets emission limit values for NO_X, SO_2 and particulate matter for large-scale industrial combustion plants for all Member States. Until June 2004, existing coal, gas and oil plants could "opt-in" or "opt-out" of the LCPD emissions standards. Those plants that opted out will be required to cease all operations by 2015 and may not operate for more than 20,000 hours after 2008. Those that opted-in, like the Company's Kilroot facility in the United Kingdom, must invest in abatement technology to achieve specific SO_2 reductions. Kilroot installed a new flue gas desulphurization system in the second quarter of 2009 in order to satisfy SO_2 reduction requirements. The Company's other coal plants in Europe are either exempt from the Directive due to their size or have opted-in but will not require any additional abatement technology to comply with the LCPD, or, in the case of AES Ballylumford 'B Station,' have opted out of the LCPD and will have to retire from operations by 2015.

Over the next four years, the Company's obligations under the LCPD with respect to our existing facilities will be replaced by obligations under Directive 2010/75/EU on industrial emissions (integrated pollution prevention and control) (the "IED"), which came into force on January 6, 2011 and has to be transposed into national legislation by Member States by January 7, 2013. Progress in implementation of the directive referred to above varies from Member State to Member State. The scope of the IED is wider than the LCPD. It aims to reduce emissions of pollutants that are alleged to be harmful to the environment and associated with cancer, asthma and acid rain, and it seeks to prevent and control air, water and soil pollution by industrial installations. It regulates emissions of a wide range of pollutants, including sulfur and nitrogen compounds, dust particles, asbestos and heavy metals.

The IED provides for a more harmonized and rigorous implementation of permit requirements for large industrial plants, seeking to optimize environmental performance by requiring adoption of the cleanest available technology, so-called Best Available Techniques ("BAT"). Guidance as to BATs applicable to various types of installations will be set out in BAT reference documents ("BREFs"), which the EU will publish based on information and emerging practices from across the EU. Regulators in all Member States will be required to take the BREFs into consideration when assessing permit requirements at each facility. Deviations from these standards will only be permitted where local and technical characteristics would make it disproportionately costly to comply.

In addition to general BAT requirements, the IED also imposes tighter, prescribed minimum emission limits for NO_X, SO_2 and dust from power plants. Some of these limits are significantly lower than under the LCPD. Existing power plants have to comply with these standards from January 1, 2016 subject to the provisions of "Transitional National Plans," which Member States may adopt to allow for existing plants to emit above the prescribed limits, in accordance with declining annual caps on NO_X, SO_2 and/or dust emissions. The annual caps for NO_X, SO_2 and/or dust emissions must align with the prescribed limits by June 30, 2020. These transitional arrangements are only available to plants which:

- received their first permit (or submitted a permit application) before November 27, 2002; and
- started operating before November 27, 2003.

Where installations are already scheduled to close by the end of 2023 or operate less than 17,500 hours after 2016, they may be permitted to operate without an upgrade, provided that they are not already exempt, pursuant to a "lifetime derogation plan," and must be agreed to by 2016 by the relevant regulator. AES generation businesses in each Member State will be required to comply with the relevant measures taken to implement the directives. At this time, the Company cannot yet determine the costs associated with the implementation of the IED in Member States that regulate the Company's subsidiaries, but it could have a material impact on the Company's consolidated operations or results.

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 became effective on June 23, 2011. The regulation will require AES Gener, the Company's Chilean subsidiary, to install emissions reduction equipment at its existing thermal plants. For further information see Item 1.Business—Regulatory Matters—Chile—*Environmental Regulations* in this Form 10-K.

Water Discharges. The Company's facilities are subject to a variety of rules governing water discharges. In particular, 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" ("BTA") 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 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 bodies of water 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 public comment period for this proposed rule has expired, and the EPA will consider the public comments with a view to issuing a final rule by July of 2012. 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 have been delegated authority and are moving forward to issue National Pollutant Discharge Elimination System ("NPDES") permits 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 State Water Resources Control Board with respect to power plant cooling water intake structures that withdraw from coastal and estuarine waters. 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 in NPDES permits that withdraw from coastal and estuarine waters in California. At this time, it is contemplated that the Company's Redondo Beach, Huntington Beach and Alamitos power plants in California (collectively, "AES Southland") will need to have in place best technology available by December 31, 2020, or repower the facilities. On April 1, 2011, AES Southland filed an Implementation Plan with the State Water Resources Control Board that indicated its intent to repower the facilities in a phased approach, with the final units being in compliance by 2024. It is anticipated that the State Water Resources Board will respond to the request by April 2012. Power plants will be required to comply with the more stringent of state or federal requirements. At present, the Company cannot predict the final requirements under the EPA Section 316(b) regulation, but the Company anticipates compliance costs could have a material impact on our consolidated financial condition or results of operations.

DP&L is in ongoing negotiations with the EPA and Ohio EPA regarding a National Pollutant Discharge Elimination System permit (the Permit) for J.M. Stuart Station. The primary issue involves the thermal discharges from the Station including the applicability of water quality standards measured either at the point of discharge into a canal that is downstream of Little Three Mile Creek or measured at the point at which the canal discharges into the Ohio River. The EPA is taking the position that the canal is a part of Little Three Mile Creek and that water quality standards should be complied with at the point of discharge into the canal. Two public hearings have been held, one by the EPA in 2011 as part of their review process for draft permits prepared by the Ohio EPA, and one by Ohio EPA in February 2012. The timing of an issuance of a final Permit is uncertain but could occur within 2012 and could impose a future deadline for compliance and compliance requirements could have a material financial effect on DP&L in the future. DP&L is attempting to resolve this issue with both the EPA and Ohio EPA.

Waste Management. In the course of operations, the Company's facilities generate solid and liquid waste materials requiring eventual disposal or processing. With the exception of coal combustion byproducts ("CCB"), the wastes are not usually physically disposed of on our property, but are shipped off site for final disposal, treatment or recycling. CCB, which consists of bottom ash, fly ash and air pollution control wastes, is disposed of at some of our coal-fired power generation plant sites using engineered, permitted landfills. Waste materials generated at our electric power and distribution facilities include CCB, oil, scrap metal, rubbish, small quantities of industrial hazardous wastes such as spent solvents, tree and land clearing wastes and polychlorinated biphenyl ("PCB") contaminated liquids and solids. The Company endeavors to ensure that all of its solid and liquid wastes are disposed of in accordance with applicable national, regional, state and local regulations. 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.

Although the public comment period for this proposed regulation has expired, the EPA issued a Notice of Data Availability ("NODA") on October 12, 2011, which allowed the public to submit additional information until November 14, 2011, which the EPA is considering prior to promulgating a final rule. The EPA is also conducting a coal ash reuse risk analysis that the EPA has stated it will complete before issuing a final rule in late 2012. The EPA is likely to retain its five-year deadline for meeting the final rule's surface impoundment requirements. 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.

Senate Bill 251

In May 2011, Senate Bill 251 became a law in the State of Indiana. Senate Bill 251 is a comprehensive bill which, among other things, provides Indiana utilities, including IPL, with a means for recovering 80% of costs incurred to comply with federal mandates through a periodic retail rate adjustment mechanism. This includes costs to comply with regulations from the EPA, FERC, NERC, Department of Energy, etc., including capital intensive requirements and/or proposals described herein, such as cooling water intake regulations, waste management and coal combustion byproducts, wastewater effluent, MISO transmission expansion costs and polychlorinated biphenyls. It does not change existing legislation that allows for 100% recovery of clean coal technology designed to reduce air pollutants ("Indiana Senate Bill 29").

Some of the most important features of Senate Bill 251 to IPL are as follows. Any energy utility in Indiana seeking to recover federally mandated costs incurred in connection with a compliance project shall apply to the Indiana Utility Regulatory Commission ("IURC") for a certificate of public convenience and necessity ("CPCN") for the compliance project. It sets forth certain factors that the IURC must consider in determining whether to grant a CPCN. It further specifies that if the IURC approves a proposed compliance project and the projected federally mandated costs associated with the project, the following apply: (i) 80% of the approved costs shall be recovered by the energy utility through a periodic retail rate adjustment mechanism, (ii) 20% of the approved costs shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the IURC, and (iii) actual costs exceeding the projected federally mandated costs of the approved compliance project by more than 25% shall require specific justification and approval before being authorized in the energy utility's next general rate case. Senate Bill 251 also requires the IURC to adopt rules to establish a voluntary clean energy portfolio standard program. Such program will provide incentives to participating electricity suppliers to obtain specified percentages of electricity from clean energy sources in accordance with clean portfolio standard goals, including requiring at least 50% of the clean energy to originate from Indiana suppliers. The goals can also be met by purchasing clean energy credits.

CERCLA. The Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA" aka "Superfund") may be the source of claims against certain of the Company's U.S. subsidiaries from time to time. There is ongoing litigation at a site known as the South Dayton Landfill where a group of companies already recognized as Potentially Responsible Parties ("PRP") have sued DP&L and other unrelated entities seeking a contribution towards the costs of assessment and remediation. DP&L is actively opposing such claims. In 2003, DP&L received notice that the EPA considers DP&L to be a PRP at the Tremont City landfill Superfund site. No actions have taken place since 2003 regarding the Tremont City landfill. The Company is unable to determine whether there will be any liability, or the size of any liability that may ultimately be assessed against DP&L at these two sites, but any such liability could be material to DP&L.

ITEM 1A. RISK FACTORS

You should consider carefully the following risks, along with the other information contained in or incorporated by reference in this Form 10-K. Additional risks and uncertainties also may adversely affect our business and operations including those discussed in Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations in this Form 10-K. If any of the following events actually occur, our business, financial results and financial condition could be materially adversely affected.

Risks Associated with our Disclosure Controls and Internal Control over Financial Reporting

We completed the remediation of our material weaknesses in internal control over financial reporting in 2008. However, our disclosure controls and procedures may not be effective in future periods if our judgments prove incorrect or new material weaknesses are identified.

For each of the fiscal quarters between December 31, 2004 and September 30, 2008, our management reported material weaknesses in our internal control over financial reporting. A material weakness is a deficiency (within the meaning of the Public Company Accounting Oversight Board ("PCAOB") Auditing Standard No. 5), or a combination of deficiencies, that adversely affects a company's ability to initiate, authorize, record, process, or report external financial data reliably in accordance with generally accepted accounting principles such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected. As a result of these material weaknesses, our management concluded that for each of the fiscal quarters from December 31, 2004 through September 30, 2008, we did not maintain effective internal control over financial reporting and concluded that our disclosure controls and procedures were not effective to provide reasonable assurance that financial information that we are required to disclose in our reports under the Exchange Act was recorded, processed, summarized and reported accurately.

To address these material weaknesses in our internal control over financial reporting, each time we prepared our annual and quarterly reports, we performed additional analyses and other post-closing procedures. These additional procedures were costly, time consuming and required us to dedicate a significant amount of our resources, including the time and attention of our senior management, toward the correction of these problems. Nevertheless, even with these additional procedures, the material weaknesses in our internal control over financial reporting caused us to have errors in our financial statements and from 2003 to 2008 we had to restate our annual financial statements six times to correct these errors.

Since December 31, 2008, our management has reported that all of our previously identified material weaknesses have been remediated and that our internal control over financial reporting and our disclosure controls have been effective. For a discussion of our internal control over financial reporting and our disclosure controls, see Item 9A.—Controls and Procedures in this Form 10-K. In making its assessment about the effectiveness of our internal control over financial reporting and our disclosure controls and procedures, management had to make certain judgments and it is possible that any number of their judgments could prove to be incorrect and that our remediation efforts did not fully and completely cure the previously identified material weaknesses. There is also the possibility that there are other material weaknesses in our internal control that are unknown to us or that new material weaknesses may develop in the future. The existence of any material weakness in our internal control over financial reporting would subject us to certain risks, including the following:

- litigation or an expansion of the SEC's informal inquiry into our restatements or the commencement of formal proceedings by the SEC or other regulatory authorities, which could require us to incur significant legal expenses and other costs or to pay damages, fines or other penalties;
- inability to file timely financial statements with the SEC, which would:
    - prevent us from offering and selling our securities pursuant to our shelf registration statement on Form S-3, which in turn would impair our ability to access the capital markets through the public sale of registered securities in a timely manner, and/or
    - depending on the length of such delay, result in covenant defaults under our senior secured credit facility and the indenture governing certain of our outstanding debt securities.
- negative publicity;
- ratings downgrades;
- inability to raise capital in the public markets and/or private markets when desired or necessary; or
- the loss or impairment of investor confidence in the Company.

Furthermore, any evaluation of the effectiveness of controls is subject to risks that those internal controls may become inadequate in future periods because of changes in business conditions, changes in accounting practice or policy, or that the degree of compliance with the revised policies or procedures deteriorates over time. Management, including our CEO and CFO, does not expect that our internal controls will prevent or detect all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs.

Our ability to timely file our financial statements and/or the effectiveness of our internal control over financial reporting may be adversely impacted in future periods due to the efforts required to adopt new accounting standards issued by the FASB as a result of the convergence of accounting standards project between the FASB and IASB.

The U.S. Financial Accounting Standards Board (the "FASB"), which establishes accounting principles generally accepted in the United States ("GAAP") guidelines that companies follow in the United States, and the International Accounting Standards Board ("IASB"), which is an international accounting standards setter outside of the United States, are presently engaged in a project to converge several accounting standards. The convergence project may result in the issuance of several new accounting standards in the future that revise existing GAAP accounting standards and which the Company may be required to adopt under GAAP.

Based on the present timeline released by the FASB, several pronouncements could be issued in final form starting in 2012. Although the release of final pronouncements is not assured and the proposed adoption dates of these standards have not been set, each new standard that the Company must comply with may require significant effort to adopt. For each new standard, the Company will be required to evaluate the impact of any accounting changes necessitated by a new standard which will include, but not be limited to, an evaluation of a new standard's impact on its financial statements and contractual arrangements; planning for and implementation of any changes to accounting systems; processes and procedures to ensure the Company properly complies with a new standard; and training personnel. To the extent that multiple standards are effective as of one date or in close proximity to one another, the Company may require considerable resources to achieve compliance with these new standards. An inability to complete these efforts prior to their effective date could have an adverse effect on our ability to timely file our financial statements with the SEC and/or the effectiveness of our internal controls over financial reporting.

Risks Related to our High Level of Indebtedness

We have a significant amount of debt, a large percentage of which is secured, which could adversely affect our business and the ability to fulfill our obligations.

As of December 31, 2011, we had approximately $22.6 billion of outstanding indebtedness on a consolidated basis. All outstanding borrowings under The AES Corporation's senior secured credit facility and certain other indebtedness are secured by certain of our assets, including the pledge of capital stock of many of The AES Corporation's directly held subsidiaries. Most of the debt of The AES Corporation's subsidiaries is secured by substantially all of the assets of those subsidiaries. Since we have such a high level of debt, a substantial portion of cash flow from operations must be used to make payments on this debt. Furthermore, since a significant percentage of our assets are used to secure this debt, this reduces the amount of collateral that is available for future secured debt or credit support and reduces our flexibility in dealing with these secured assets. This high level of indebtedness and related security could have other important consequences to us and our investors, including:

- making it more difficult to satisfy debt service and other obligations at the holding company and/or individual subsidiaries;
- increasing the likelihood of a downgrade of our debt, which could cause future debt costs and/or payments to increase under our debt and related hedging instruments and consume an even greater portion of cash flow;
- increasing our vulnerability to general adverse industry conditions and economic conditions, including but not limited to adverse changes in foreign exchange rates and commodity prices;
- reducing the availability of cash flow to fund other corporate purposes and grow our business;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry;
- placing us at a competitive disadvantage to our competitors that are not as highly leveraged; and
- limiting, along with the financial and other restrictive covenants relating to such indebtedness, among other things, our ability to borrow additional funds as needed or take advantage of business opportunities as they arise, pay cash dividends or repurchase common stock.

The agreements governing our indebtedness, including the indebtedness of our subsidiaries, limit, but do not prohibit the incurrence of additional indebtedness. To the extent we become more leveraged, the risks described above would increase. Further, our actual cash requirements in the future may be greater than expected. Accordingly, our cash flows may not be sufficient to repay at maturity all of the outstanding debt as it becomes due and, in that event, we may not be able to borrow money, sell assets, raise equity or otherwise raise funds on acceptable terms or at all to refinance our debt as it becomes due. See Note 11—*Debt* included in Item 8. of this Form 10-K for a schedule of our debt maturities.

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.

The AES Corporation is a holding company with no material assets other than the stock of its subsidiaries. All of The AES Corporation's revenue is generated through its subsidiaries. Accordingly, almost all of The AES

Corporation's cash flow is generated by the operating activities of its subsidiaries. Therefore, The AES Corporation's ability to make payments on its indebtedness and to fund its other obligations is dependent not only on the ability of its subsidiaries to generate cash, but also on the ability of the subsidiaries to distribute cash to it in the form of dividends, fees, interest, loans or otherwise.

However, our subsidiaries face various restrictions in their ability to distribute cash to The AES Corporation. Most of the subsidiaries are obligated, pursuant to loan agreements, indentures or project financing arrangements, to satisfy certain restricted payment covenants or other conditions before they may make distributions to The AES Corporation. In addition, the payment of dividends or the making of loans, advances or other payments to The AES Corporation may be subject to other contractual, legal or regulatory restrictions. Business performance and local accounting and tax rules may limit the amount of retained earnings that may be distributed to us as a dividend. Subsidiaries in foreign countries may also be prevented from distributing funds to The AES Corporation as a result of foreign governments restricting the repatriation of funds or the conversion of currencies. Any right that The AES Corporation has to receive any assets of any of its subsidiaries upon any liquidation, dissolution, winding up, receivership, reorganization, bankruptcy, insolvency or similar proceedings (and the consequent right of the holders of The AES Corporation's indebtedness to participate in the distribution of, or to realize proceeds from, those assets) will be effectively subordinated to the claims of any such subsidiary's creditors (including trade creditors and holders of debt issued by such subsidiary).

The AES Corporation could receive less funds than it expects as a result of the current challenges facing the global and local economies, which could impact the performance of our businesses and their ability to distribute cash to The AES Corporation. For further discussion of the macroeconomic environment and its impact on our business, see Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations—*Global Economic Conditions*.

The AES Corporation's subsidiaries are separate and distinct legal entities and, unless they have expressly guaranteed any of The AES Corporation's indebtedness, have no obligation, contingent or otherwise, to pay any amounts due pursuant to such debt or to make any funds available whether by dividends, fees, loans or other payments. While some of The AES Corporation's subsidiaries guarantee the Parent's indebtedness under the Parent's senior secured credit facility, none of its subsidiaries guarantee, or are otherwise obligated with respect to, its outstanding public debt securities.

Even though The AES Corporation is a holding company, existing and potential future defaults by subsidiaries or affiliates could adversely affect The AES Corporation.

We attempt to finance our domestic and foreign projects primarily under loan agreements and related documents which, except as noted below, require the loans to be repaid solely from the project's revenues and provide that the repayment of the loans (and interest thereon) is secured solely by the capital stock, physical assets, contracts and cash flow of that project subsidiary or affiliate. This type of financing is usually referred to as non-recourse debt or "project financing." In some project financings, The AES Corporation has explicitly agreed to undertake certain limited obligations and contingent liabilities, most of which by their terms will only be effective or will be terminated upon the occurrence of future events. These obligations and liabilities take the form of guarantees, indemnities, letter of credit reimbursement agreements and agreements to pay, in certain circumstances, the project lenders or other parties.

As of December 31, 2011, we had approximately $22.6 billion of outstanding indebtedness on a consolidated basis, of which approximately $6.5 billion was recourse debt of The AES Corporation and approximately $16.1 billion was non-recourse debt. In addition, we have outstanding guarantees, letters of credit, and other credit support commitments which are further described in this Form 10-K in Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations—*Capital Resources and Liquidity—Parent Company Liquidity*.

Some of our subsidiaries are currently in default with respect to all or a portion of their outstanding indebtedness. The total debt classified as current in our consolidated balance sheets related to such defaults was $1.3 billion at December 31, 2011. While the lenders under our non-recourse project financings generally do not have direct recourse to The AES Corporation (other than to the extent of any credit support given by The AES Corporation), defaults there under can still have important consequences for The AES Corporation, including, without limitation:

- reducing The AES Corporation's receipt of subsidiary dividends, fees, interest payments, loans and other sources of cash since the project subsidiary will typically be prohibited from distributing cash to The AES Corporation during the pendency of any default;
- triggering The AES Corporation's obligation to make payments under any financial guarantee, letter of credit or other credit support which The AES Corporation has provided to or on behalf of such subsidiary;
- causing The AES Corporation to record a loss in the event the lender forecloses on the assets;
- triggering defaults in The AES Corporation's outstanding debt and trust preferred securities. For example, The AES Corporation's senior secured credit facility and outstanding senior notes include events of default for certain bankruptcy related events involving material subsidiaries. In addition, The AES Corporation's senior secured credit facility includes certain events of default relating to accelerations of outstanding debt of material subsidiaries;
- the loss or impairment of investor confidence in the Company; or
- foreclosure on the assets that are pledged under the nonrecourse loans, therefore eliminating any and all potential future benefits derived from those assets.

None of the projects that are currently in default are owned by subsidiaries that meet the applicable definition of materiality in The AES Corporation's senior secured credit facility or other debt agreements in order for such defaults to trigger an event of default or permit acceleration under such indebtedness. However, as a result of future mix of distributions, write-down of assets, dispositions and other matters that affect our financial position and results of operations, it is possible that one or more of these subsidiaries could fall within the applicable definition of materiality and thereby upon an acceleration of such subsidiary's debt, trigger an event of default and possible acceleration of the indebtedness under The AES Corporation's senior secured credit facility. The risk of such defaults may have increased as a result of the deteriorating global economy. For further discussion of these conditions, see Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations—*Global Economic Conditions* of this Form 10-K.

Risks Associated with our Ability to Raise Needed Capital

The AES Corporation has significant cash requirements and limited sources of liquidity.

The AES Corporation requires cash primarily to fund:

- principal repayments of debt;
- interest and preferred dividends;
- acquisitions;
- construction and other project commitments;
- other equity commitments, including business development investments;
- equity repurchases and/or cash dividends on our common stock that we may declare in the future;
- taxes; and
- Parent Company overhead costs.

The AES Corporation's principal sources of liquidity are:

- dividends and other distributions from its subsidiaries;
- proceeds from debt and equity financings at the Parent Company level; and
- proceeds from asset sales.

For a more detailed discussion of The AES Corporation's cash requirements and sources of liquidity, please see Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations—*Capital Resources and Liquidity* of this Form 10-K.

While we believe that these sources will be adequate to meet our obligations at the Parent Company level 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 or commercial lending markets, the operating and financial performance of our subsidiaries, exchange rates, our ability to sell assets, and the ability of our subsidiaries to pay dividends. Any number of assumptions could prove to be incorrect and therefore there can be no assurance that these sources will be available when needed or that our actual cash requirements will not be greater than expected. For example, in recent years, certain financial institutions have gone bankrupt. In the event that a bank who is party to our senior secured credit facility or other facilities goes bankrupt or is otherwise unable to fund its commitments, we would need to replace that bank in our syndicate or risk a reduction in the size of the facility, which would reduce our liquidity. In addition, our cash flow may not be sufficient to repay at maturity the entire principal outstanding under our credit facilities and our debt securities and we may have to refinance such obligations. There can be no assurance that we will be successful in obtaining such refinancing on terms acceptable to us or at all and any of these events could have a material effect on us.

Our ability to grow our business could be materially adversely affected if we were unable to raise capital on favorable terms.

From time to time, we rely on access to capital markets as a source of liquidity for capital requirements not satisfied by operating cash flows. Our ability to arrange for financing on either a recourse or non-recourse basis and the costs of such capital are dependent on numerous factors, some of which are beyond our control, including:

- general economic and capital market conditions;
- the availability of bank credit;
- investor confidence;
- the financial condition, performance and prospects of The AES Corporation in general and/or that of any subsidiary requiring the financing as well as companies in our industry or similar financial circumstances; and
- changes in tax and securities laws which are conducive to raising capital.

Should future access to capital not be available to us, we may have to sell assets or decide not to build new plants or expand or improve existing facilities, either of which would affect our future growth, results of operations or financial condition.

A downgrade in the credit ratings of The AES Corporation or its subsidiaries could adversely affect our ability to access the capital markets which could increase our interest costs or adversely affect our liquidity and cash flow.

If any of the credit ratings of The AES Corporation or its subsidiaries were to be downgraded, our ability to raise capital on favorable terms could be impaired and our borrowing costs would increase. Furthermore, depending on The AES Corporation's credit ratings and the trading prices of its equity and debt securities, counterparties may no longer be as willing to accept general unsecured commitments by The AES Corporation to provide credit support. Accordingly, with respect to both new and existing commitments, The AES Corporation may be required to provide some other form of assurance, such as a letter of credit and/or collateral, to backstop or replace any credit support by The AES Corporation. There can be no assurance that such counterparties will accept such guarantees or that AES could arrange such further assurances in the future. In addition, to the extent The AES Corporation is required and able to provide letters of credit or other collateral to such counterparties, it will limit the amount of credit available to The AES Corporation to meet its other liquidity needs.

We may not be able to raise sufficient capital to fund "greenfield" projects in certain less developed economies which could change or in some cases adversely affect our growth strategy.

Part of our strategy is to grow our business by developing Generation and Utility businesses in less developed economies where the return on our investment may be greater than projects in more developed economies. Commercial lending institutions sometimes refuse to provide non-recourse project financing in certain less developed economies, and in these situations we have sought and will continue to seek direct or indirect (through credit support or guarantees) project financing from a limited number of multilateral or bilateral international financial institutions or agencies. As a precondition to making such project financing available, the lending institutions may also require governmental guarantees of certain project and sovereign related risks. There can be no assurance, however, that project financing from the international financial agencies or that governmental guarantees will be available when needed, and if they are not, we may have to abandon the project or invest more of our own funds which may not be in line with our investment objectives and would leave less funds for other projects. These risks have increased as a result of the recent credit crisis and the deteriorating global economy. For further discussion of these global economic conditions and their potential impact on the Company, see Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations—*Global Economic Conditions*.

External Risks Associated with Revenue and Earnings Volatility

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.

Some of our businesses sell electricity in the wholesale spot markets in cases where they operate wholly or partially without long-term power sales agreements. Our Generation and Utility businesses may also buy electricity in the wholesale spot markets. As a result, we are exposed to the risks of rising and falling prices in those markets. The open market wholesale prices for electricity are very volatile and often reflect the fluctuating cost of coal, natural gas or oil. Consequently, any changes in the supply and cost of coal, natural gas, or oil may impact the open market wholesale price of electricity.

Volatility in market prices for fuel and electricity may result from among other things:

- plant availability in the markets generally;
- availability and effectiveness of transmission facilities owned and operated by third parties;
- competition;
- demand for energy commodities;
- electricity usage;
- seasonality;
- interest rate and foreign exchange rate fluctuation;
- availability and price of emission credits;
- input prices;

- hydrology and other weather conditions;
- illiquid markets;
- transmission or transportation constraints or inefficiencies;
- availability of competitively priced renewables sources;
- available supplies of natural gas, crude oil and refined products, and coal;
- generating unit performance;
- natural disasters, terrorism, wars, embargoes, and other catastrophic events;
- energy, market and environmental regulation, legislation and policies;
- geopolitical concerns affecting global supply of oil and natural gas; and
- general economic conditions in areas where we operate which impact energy consumption.

Our financial position and results of operations may fluctuate significantly due to fluctuations in currency exchange rates experienced at our foreign operations.

Our exposure to currency exchange rate fluctuations results primarily from the translation exposure associated with the preparation of the Consolidated Financial Statements, as well as from transaction exposure associated with transactions in currencies other than an entity's functional currency. While the Consolidated Financial Statements are reported in U.S. Dollars, the financial statements of many of our subsidiaries outside the United States are prepared using the local currency as the functional currency and translated into U.S. Dollars by applying appropriate exchange rates. As a result, fluctuations in the exchange rate of the U.S. Dollar relative to the local currencies where our subsidiaries outside the United States report could cause significant fluctuations in our results. In addition, while our expenses with respect to foreign operations are generally denominated in the same currency as corresponding sales, we have transaction exposure to the extent receipts and expenditures are not denominated in the subsidiary's functional currency.

We also experience foreign transaction exposure to the extent monetary assets and liabilities, including debt, are in a different currency than the subsidiary's functional currency. Moreover, the costs of doing business abroad may increase as a result of adverse exchange rate fluctuations. Our financial position and results of operations have been affected by fluctuations in the value of a number of currencies, primarily the Euro, Brazilian real, Argentine peso, Chilean peso, Colombian peso and Philippine peso.

We may not be adequately hedged against our exposure to changes in commodity prices or interest rates.

We routinely enter into contracts to hedge a portion of our purchase and sale commitments for electricity, fuel requirements and other commodities to lower our financial exposure related to commodity price fluctuations. As part of this strategy, we routinely utilize fixed price forward physical purchase and sales contracts, futures, financial swaps, and option contracts traded in the over-the-counter markets or on exchanges. We also enter into contracts which help us hedge our interest rate exposure on variable rate debt. However, we may not cover the entire exposure of our assets or positions to market price or interest rate volatility, and the coverage will vary over time. Furthermore, the risk management practices we have in place may not always perform as planned. In particular, if prices of commodities or interest rates significantly deviate from historical prices or interest rates or if the price or interest rate volatility or distribution of these changes deviates from historical norms, our risk management practices may not protect us from significant losses. As a result, fluctuating commodity prices or interest rates may negatively impact our financial results to the extent we have unhedged or inadequately hedged positions. In addition, certain types of economic hedging activities may not qualify for hedge accounting under GAAP, resulting in increased volatility in our net income. The Company may also suffer losses associated with "basis risk" which is the assumed relative correlation of performance between the intended hedge instrument and the targeted underlying exposure. Furthermore, there is a risk that the current counterparties to these arrangements may fail or are unable to perform their obligations under these arrangements.

In the past few years, we have faced substantial challenges in North America as a result of high coal prices relative to natural gas, which has affected the results of certain of our coal plants in the region, particularly those which are merchant plants that are exposed to market risk and those that have hybrid merchant risk, meaning those businesses that have a PPA in place but purchase fuel at market prices or under short term contracts. For our businesses with PPA pricing that does not perfectly pass through our fuel costs, the businesses attempt to manage the exposure through flexible fuel purchasing and timing of entry and terms of our fuel supply agreements; however, these risk management efforts may not be successful and the resulting commodity exposure could have a material impact on these businesses and/or our results of operations. In recent years, our coal-fired plants in New York and our petroleum coke-fired plant in Texas have been affected by market conditions, including the commodity price risks noted above. As a result of these and other challenges, AES Thames, our 208 MW coal-fired generation business in Connecticut, filed for bankruptcy protection in January 2011 and is in the process of liquidation and AES Eastern Energy filed for bankruptcy protection in December 2011.

In our North America Utility Businesses, DPL and IPL, there may be a portion of their generating facilities output that is sold into the merchant markets and subject to variability in dark spreads. The level of generation subject to dark spread exposure is dependent upon retail demand obligations and hedge levels in place, which, as noted above, can adversely impact the performance of these businesses and our results of operations.

Supplier and/or customer concentration may expose the Company to significant financial credit or performance risks.

We often rely on a single contracted supplier or a small number of suppliers for the provision of fuel, transportation of fuel and other services required for the operation of certain of our facilities. If these suppliers cannot perform, we would seek to meet our fuel requirements by purchasing fuel at market prices, exposing us to market price volatility and the risk that fuel and transportation may not be available during certain periods at any price, which could be lower than contracted prices and would expose these businesses to considerable price volatility.

At times, we rely on a single customer or a few customers to purchase all or a significant portion of a facility’s output, in some cases under long-term agreements that account for a substantial percentage of the anticipated revenue from a given facility. We have also hedged a portion of our exposure to power price fluctuations through forward fixed price power sales. Counterparties to these agreements may breach or may be unable to perform their obligations. We may not be able to enter into replacement agreements on terms as favorable as our existing agreements, or at all. If we were unable to enter into replacement PPAs, these businesses may have to sell power at market prices.

The failure of any supplier or customer to fulfill its contractual obligations to The AES Corporation or our subsidiaries could have a material adverse effect on our financial results. Consequently, the financial performance of our facilities is dependent on the credit quality of, and continued performance by, suppliers and customers.

The market pricing of our common stock has been volatile and may continue to be volatile in future periods.

The market price for our common stock has been volatile in the past, and the price of our common stock could fluctuate substantially in the future. Stock price movements on a quarter by quarter basis for the past two years are set forth in Item 5.—Market—Market Information of this Form 10-K. Factors that could affect the price of our common stock in the future include general conditions in our industry, in the power markets in which we participate and in the world, including environmental and economic developments, over which we have no control, as well as developments specific to us, including, risks that could result in revenue and earnings volatility as well as other risk factors described in this Item 1A.—Risk Factors and those matters described in Item 7.—Management's Discussion and Analysis of Financial Conditions and Results of Operations.

Risks Associated with our Operations

We do a significant amount of business outside the United States, including in developing countries, which presents significant risks.

A significant amount of our revenue is generated outside the United States and a significant portion of our international operations is conducted in developing countries. Part of our growth strategy is to expand our business in developing countries because the growth rates and the opportunity to implement operating improvements and achieve higher operating margins may be greater than those typically achievable in more developed countries. International operations, particularly the operation, financing and development of projects in developing countries, entail significant risks and uncertainties, including, without limitation:

- economic, social and political instability in any particular country or region;
- adverse changes in currency exchange rates;
- government restrictions on converting currencies or repatriating funds;
- unexpected changes in foreign laws and regulations or in trade, monetary or fiscal policies;
- high inflation and monetary fluctuations;
- restrictions on imports of coal, oil, gas or other raw materials required by our generation businesses to operate;
- threatened or consummated expropriation or nationalization of our assets by foreign governments;
- difficulties in hiring, training and retaining qualified personnel, particularly finance and accounting personnel with GAAP expertise;
- unwillingness of governments, government agencies, similar organizations or other counterparties to honor their contracts;
- unwillingness of governments, government agencies, courts or similar bodies to enforce contracts that are economically advantageous to subsidiaries of the Company and economically unfavorable to counterparties, against such counterparties, whether such counterparties are governments or private parties;
- inability to obtain access to fair and equitable political, regulatory, administrative and legal systems;
- adverse changes in government tax policy;
- difficulties in enforcing our contractual rights or enforcing judgments or obtaining a favorable result in local jurisdictions; and
- potentially adverse tax consequences of operating in multiple jurisdictions.

Any of these factors, by itself or in combination with others, could materially and adversely affect our business, results of operations and financial condition. For example, partly in response to challenging business and political conditions in Kazakhstan, in 2008, we sold certain businesses in that country. As another example, in the second quarter of 2007, we sold our stake in EDC to Petróleos de Venezuela, S.A., the state-owned energy company in Venezuela after Venezuelan President Hugo Chávez threatened to expropriate the electricity business in Venezuela. In connection with the sale, we recognized an impairment charge of approximately $680 million. In addition, our Latin American operations experience volatility in revenues and gross margin which have caused and are expected to cause significant volatility in our results of operations and cash flows. The volatility is caused by regulatory and economic difficulties, political instability and currency devaluations being experienced in many of these countries. This volatility reduces the predictability and enhances the uncertainty associated with cash flows from these businesses.

The operation of power generation and distribution facilities involves significant risks that could adversely affect our financial results. We and/or our subsidiaries may not have adequate insurance coverage for liabilities.

We are in the business of generating and distributing electricity, which involves certain risks that can adversely affect financial and operating performance, including:

- changes in the availability of our generation facilities or distribution systems due to increases in scheduled and unscheduled plant outages, equipment failure, failure of transmission systems, labor disputes, disruptions in fuel supply, inability to comply with regulatory or permit requirements or catastrophic events such as fires, floods, storms, hurricanes, earthquakes, explosions, terrorist acts or other similar occurrences; and
- changes in our operating cost structure including, but not limited to, increases in costs relating to: gas, coal, oil and other fuel; fuel transportation; purchased electricity; operations, maintenance and repair; environmental compliance, including the cost of purchasing emissions offsets and capital expenditures to install environmental emission equipment; transmission access; and insurance.

Our businesses require reliable transportation sources (including related infrastructure such as roads, ports and rail), power sources and water sources to access and conduct operations. The availability and cost of this infrastructure affects capital and operating costs and levels of production and sales. Limitations, or interruptions in transportation including as a result of third parties intentionally or unintentionally disrupting the facilities of our subsidiaries, could impede their ability to produce electricity. This could have a material adverse effect on our businesses' results of operations, financial condition and prospects.

In addition, a portion of our generation facilities were constructed many years ago. Older generating equipment may require significant capital expenditures for maintenance. The equipment at our plants, whether old or new, is also likely to require periodic upgrading, improvement or repair, and replacement equipment or parts may be difficult to obtain in circumstances where we rely on a single supplier or a small number of suppliers. The inability to obtain replacement equipment or parts may impact the ability of our plants to perform and could therefore have a material impact on our business and results of operations. Breakdown or failure of one of our operating facilities may prevent the facility from performing under applicable power sales agreements which, in certain situations, could result in termination of a power purchase or other agreement or incurrence of a liability for liquidated damages and/or other penalties.

As a result of the above risks and other potential hazards associated with the power generation and distribution industries, we may from time to time become exposed to significant liabilities for which we may not have adequate insurance coverage. Power generation involves hazardous activities, including acquiring, transporting and unloading fuel, operating large pieces of rotating equipment and delivering electricity to transmission and distribution systems. In addition to natural risks, such as earthquakes, floods, lightning, hurricanes and wind, hazards, such as fire, explosion, collapse and machinery failure, are inherent risks in our operations which may occur as a result of inadequate internal processes, technological flaws, human error or certain external events. The control and management of these risks depend upon adequate development and training of personnel and on the existence of operational procedures, preventative maintenance plans and specific programs supported by quality control systems which reduce, but do not eliminate the possibility of the occurrence and impact of these risks.

The hazards described above can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, contamination of, or damage to, the environment and suspension of operations. The occurrence of any one of these events may result in our being named as a defendant in lawsuits asserting claims for substantial damages, environmental cleanup costs, personal injury and fines and/or penalties. We maintain an amount of insurance protection that we believe is customary, but there can be no assurance that our insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject. A claim for which we are not fully insured or insured at all could hurt our financial results and materially harm our financial condition. Further, due to rising insurance costs and changes in the insurance markets, we cannot provide assurance that insurance coverage will continue to be available on terms similar to those presently available to us or at all. Any losses not covered by insurance could have a material adverse effect on our financial condition, results of operations or cash flows.

Our businesses' insurance does not cover every potential risk associated with its operations. Adequate coverage at reasonable rates is not always obtainable. In addition, insurance may not fully cover the liability or the consequences of any business interruptions such as equipment failure or labor dispute. The occurrence of a significant adverse event not fully or partially covered by insurance could have a material adverse effect on the Company's business, results or operations, financial condition and prospects.

Any of the above risks could have a material adverse effect on our business and results of operations.

Our inability to attract and retain skilled people could have a material adverse effect on our operations.

Our operating success and ability to carry out growth initiatives depends in part on our ability to retain executives and to attract and retain additional qualified personnel who have experience in our industry and in operating a company of our size and complexity, including people in our foreign businesses. The inability to attract and retain qualified personnel could have a material adverse effect on our business, because of the difficulty of promptly finding qualified replacements. In particular, we routinely are required to assess the financial and tax impacts of complicated business transactions which occur on a worldwide basis. These assessments are dependent on hiring personnel on a worldwide basis with sufficient expertise in U.S. GAAP to timely and accurately comply with United States reporting obligations. An inability to maintain adequate internal accounting and managerial controls and hire and retain qualified personnel could have an adverse effect on our financial and tax reporting.

We have contractual obligations to certain customers to provide full requirements service, which makes it difficult to predict and plan for load requirements and may result in increased operating costs to certain of our businesses.

We have contractual obligations to certain customers to supply power to satisfy all or a portion of their energy requirements. The uncertainty regarding the amount of power that our power generation and distribution facilities must be prepared to supply to customers may increase our operating costs. A significant under- or over-estimation of load requirements could result in our facilities not having enough or having too much power to cover their obligations, in which case we would be required to buy or sell power from or to third parties at prevailing market prices. Those prices may not be favorable and thus could increase our operating costs.

We may not be able to enter into long-term contracts, which reduce volatility in our results of operations. Even when we successfully enter into long-term contracts, our generation businesses are often dependent on one or a limited number of customers and a limited number of fuel suppliers.

Many of our generation plants conduct business under long-term contracts. In these instances, we rely on power sales contracts with one or a limited number of customers for the majority of, and in some cases all of, the relevant plant's output and revenues over the term of the power sales contract. The remaining terms of the power sales contracts range from 1 to 25 years. In many cases, we also limit our exposure to fluctuations in fuel prices by entering into long-term contracts for fuel with a limited number of suppliers. In these instances, the cash flows and results of operations are dependent on the continued ability of customers and suppliers to meet their obligations under the relevant power sales contract or fuel supply contract, respectively. Some of our long-term power sales agreements are at prices above current spot market prices and some of our long-term fuel supply contracts are at prices below current market prices. The loss of significant power sales contracts or fuel supply contracts, or the failure by any of the parties to such contracts that prevents us from fulfilling our obligations there under, could have a material adverse impact on our business, results of operations and financial condition. In addition, depending on market conditions and regulatory regimes, it may be difficult for us to secure long-term contracts, either where our current contracts are expiring or for new development projects. The inability to enter into long-term contracts could require many of our businesses to purchase inputs at market prices and sell electricity into spot markets, which may not be favorable. For example, during the past several years, various governmental authorities in Europe have terminated or declined to fulfill their obligations under long-term contracts with our subsidiaries. In 2008, as part of the accession to the European Union, the Hungarian government terminated all long-term PPAs, including AES Tisza's PPA, as of December 31, 2008. Partly as a result of the termination, AES Tisza's results of operations declined and we were required to record an $85 million asset impairment charge for AES Tisza in the third quarter of 2010 and another impairment charge of $52 million in 2011. Pursuant to the terms of its PPA, Kilroot in Northern Ireland received notice from the Utility Regulator directing Kilroot and NIE Energy to terminate the Generating Unit Agreements for the two coal fired units effective November 1, 2010 and, as a result, the performance (and contributions to income and cash flow) from Kilroot will decline in the future when compared to prior years. Furthermore, these businesses (and any other businesses whose long-term contracts may be challenged) may have to sell electricity into the spot markets. In addition, in connection with Bulgaria's ascension into the EU, the EC has opened an investigation into alleged anticompetitive behavior in the Bulgarian electricity market, which could have a material impact on our results of operations. Further information on the EC investigation is set forth in Item 1. Business— Regulatory Matters—*Bulgaria* in this Form 10-K. Because of the volatile nature of inputs and power prices, the inability to secure long-term contracts could generate increased volatility in our earnings and cash flows and could generate substantial losses (or result in a write-down of assets), which could have a material impact on our business and results of operations.

We have sought to reduce counterparty credit risk under our long-term contracts in part by entering into power sales contracts with utilities or other customers of strong credit quality and by obtaining guarantees from certain sovereign governments of the customer's obligations. However, many of our customers do not have, or have failed to maintain, an investment-grade credit rating, and our Generation business cannot always obtain government guarantees and if they do, the government does not always have an investment grade credit rating. We have also sought to reduce our credit risk by locating our plants in different geographic areas in order to mitigate the effects of regional economic downturns. However, there can be no assurance that our efforts to mitigate this risk will be successful. These risks have increased as a result of the deteriorating and volatile global economy. For further discussion of these global economic conditions and their potential impact on the Company, see Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations—*Global Economic Conditions* in this Form 10-K.

Competition is increasing and could adversely affect us.

The power production markets in which we operate are characterized by numerous strong and capable competitors, many of whom may have extensive and diversified developmental or operating experience (including both domestic and international) and financial resources similar to or greater than ours. Further, in recent years, the power production industry has been characterized by strong and increasing competition with respect to both obtaining power sales agreements and acquiring existing power generation assets. In certain markets, these factors have caused reductions in prices contained in new power sales agreements and, in many cases, have caused higher acquisition prices for existing assets through competitive bidding practices. The evolution of competitive electricity markets and the development of highly efficient gas-fired power plants have also caused, or are anticipated to cause, price pressure in certain power markets where we sell or intend to sell power. These competitive factors could have a material adverse effect on us.

Some of our subsidiaries participate in defined benefit pension plans and their net pension plan obligations may require additional significant contributions.

Certain of our subsidiaries have defined benefit pension plans covering substantially all of their respective employees. Of the twenty-six defined benefit plans, four are at United States subsidiaries and the remaining plans are at foreign subsidiaries. Pension costs are based upon a number of actuarial assumptions, including an expected long-term rate of return on pension plan assets, the expected life span of pension plan beneficiaries and the discount rate used to determine the present value of future pension obligations. Any of these assumptions could prove to be wrong, resulting in a shortfall of pension plan assets compared to pension obligations under the pension plan. The Company periodically evaluates the value of the pension plan assets to ensure that they will be sufficient to fund the respective pension obligations. The Company's exposure to market volatility is mitigated to some extent due to the fact that the asset allocations in our largest plans are more heavily weighted to investments in fixed income securities that have not been as severely impacted by the global recession. Future downturns in the debt and/or equity markets, or the inaccuracy of any of our significant assumptions underlying the estimates of our subsidiaries' pension plan obligations, could result in an increase in pension expense and future funding requirements, which may be material. Our subsidiaries who participate in these plans are responsible for satisfying the funding requirements required by law in their respective jurisdiction for any shortfall of pension plan assets compared to pension obligations under the pension plan. This may necessitate additional cash contributions to the pension plans that could adversely affect the Parent Company and our subsidiaries' liquidity.

For additional information regarding the funding position of the Company's pension plans, see Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations—*Critical Accounting—Estimates—Pension and Postretirement Obligations* and Note 14 to our Consolidated Financial Statements included in this Form 10-K.

Our business is subject to substantial development uncertainties.

Certain of our subsidiaries and affiliates are in various stages of developing and constructing "greenfield" power plants, some but not all of which have signed long-term contracts or made similar arrangements for the sale of electricity. Successful completion depends upon overcoming substantial risks, including, but not limited to, risks relating to failures of siting, financing, construction, permitting, governmental approvals, commissioning delays, or the potential for termination of the power sales contract as a result of a failure to meet certain milestones. Timing of equipment purchases can also pose financial risks to the Company. As part of our development process, we attempt to make purchases of equipment and/or materials as needed. However, from time to time, there may be excess demand for certain types of equipment with substantial delays between the time we place orders and receive delivery. In those instances, to avoid construction delays and costs associated with the inability to own and place such equipment and/or materials into service when needed in the construction process, we may place orders well in advance of deployment. In some cases, we may order such equipment and/or materials without yet having a specific project where the equipment and/or materials will be deployed, in anticipation that equipment and materials will be needed at the time of delivery. However, there is a risk that at the time of delivery, we are required to accept delivery and pay for such equipment and/or materials, even though no project has materialized where these items will be used. This can result in our having to incur material equipment and/or material costs, with no deployment plan at delivery. Financing risk has also increased as a result of the deterioration of the global economy and the crisis in the financial markets and, as a result, we may forgo certain development opportunities. We believe that capitalized costs for projects under development are recoverable; however, there can be no assurance that any individual project will be completed and reach commercial operation. If these development efforts are not successful, we may abandon a project under development and write off the costs incurred in connection with such project. At the time of abandonment, we would expense all capitalized development costs incurred in connection therewith and could incur additional losses associated with any related contingent liabilities.

In some of our joint venture projects and businesses, we have granted protective rights to minority holders or we own less than a majority of the equity in the project or business and do not manage or otherwise control the project or business, which entails certain risks.

We have invested in some joint ventures where we own less than a majority of the voting equity in the venture. Very often, one of our subsidiaries seeks to exert a degree of influence with respect to the management and operation of projects or businesses in which we have less than a majority of the ownership interests by operating the project or business pursuant to a management contract, negotiating to obtain positions on management committees or to receive certain limited governance rights, such as rights to veto significant actions. However, we do not always have this type of control over the project or business in every instance and we may be dependent on our co-venturers to operate such projects or businesses. Our co-venturers may not have the level of experience, technical expertise, human resources, management and other attributes necessary to operate these projects or businesses optimally. The approval of co-venturers also may be required for us to receive distributions of funds from projects or to transfer our interest in projects or businesses.

In some joint venture agreements where we do have majority control of the voting securities, we have entered into shareholder agreements granting protective minority rights to the other shareholders. For example, Companhia Brasiliana de Energia ("Brasiliana") is a holding company in which we have a controlling equity interest and through which we own three of our four Brazilian businesses: Eletropaulo, Tietê and Uruguaiana. We entered into a shareholders' agreement with an affiliate of the Brazilian National Development Bank ("BNDES") which owns more than 49 % of the voting equity of Brasiliana. Among other things, the shareholders' agreement requires the consent of both parties before taking certain corporate actions, grants both parties rights of first refusal in connection with the sale of interests in Brasiliana and grants certain drag-along rights to BNDES. In May 2007, BNDES notified us that it intends to sell all of its interest in Brasiliana pursuant to a public auction (the "Brasiliana Sale"). BNDES also informed us that if we fail to exercise our right of first refusal to purchase all of its interest in Brasiliana, then BNDES intends to exercise its drag-along rights under the shareholders' agreement and cause us to sell all of our interests in Brasiliana in the Brasiliana Sale as well. BNDES has since suspended the auction; however, BNDES may determine to recommence a sale process in the future. In that event, after the auction, if a third party offer has been received in the Brasiliana Sale, we will have 30 days to exercise our right of first refusal to purchase all of BNDES's interest in Brasiliana on the same terms as the third-party offer. If we do not exercise this right and BNDES proceeds to exercise its drag-along rights, then we may be forced to sell all of our interest in Brasiliana. Due to the uncertainty in the sale price at this point in time, we are uncertain whether we will exercise our right of first refusal should BNDES receive a valid third-party offer in the Brasiliana Sale and, if we do, whether we would do it alone or with joint venture partners. Even if we desire to exercise our right of first refusal, we cannot assure that we will have the cash on hand or that debt or equity financing will be available at acceptable terms in order to purchase BNDES's interest in Brasiliana. If we do not exercise our right of first refusal, we cannot be assured that we will not have to record a loss if the sale price is below the book value of our investment in Brasiliana.

Our renewable energy projects and other initiatives face considerable uncertainties including, development, operational and regulatory challenges.

Wind Generation, AES Solar, our greenhouse gas emissions reductions projects ("GHG Emissions Reduction Projects"), and our investments in projects such as energy storage are subject to substantial risks. Projects of this nature have been developed through advancement in technologies which may not be proven or whose commercial application is limited, and which are unrelated to our core business. Some of these business lines are dependent upon favorable regulatory incentives to support continued investment, and there is significant uncertainty about the extent to which such favorable regulatory incentives will be available in the future. For example, several European countries have recently faced a debt crisis, which has or may result in government austerity measures, including, repeal or reduction of certain subsidies. If additional subsidies or other incentives are repealed or reduced, or sovereign governments are unable or unwilling to fulfill their commitments or maintain favorable regulatory incentives for renewables, this could materially impact our renewable businesses, results of operations and financial condition, and impact the ability of the affected businesses to continue or grow their operations. 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, which could also have a material impact on our results of operations.

Furthermore, production levels for our wind, solar, and GHG Emissions Reduction Projects may be dependent upon adequate wind, sunlight, or biogas production which can vary significantly from period to period, resulting in volatility in production levels and profitability. For example, for our wind projects, wind resource estimates are based on historical experience when available and on wind resource studies conducted by an independent engineer, and are not expected to reflect actual wind energy production in any given year. With regard to GHG Emissions Reduction Projects, there is particular uncertainty about whether agreements providing incentives for reductions in greenhouse gas emissions, such as the Kyoto Protocol, will continue and whether countries around the world will enact or maintain legislation that provides incentives for reductions in greenhouse gas emissions, without which such projects may not be economical or financing for such projects may become unavailable.

As a result, renewable energy projects face considerable risk relative to our core business, including the risk that favorable regulatory regimes expire or are adversely modified. In addition, because certain of these projects depend on technology outside of our expertise in Generation and Utility businesses, there are risks associated with our ability to develop and manage such projects profitably. Furthermore, at the development or acquisition stage, because of the nascent nature of these industries or the limited experience with the relevant technologies, our ability to predict actual performance results may be hindered and the projects may not perform as predicted. There are also risks associated with the fact that some of these projects exist in new or emerging markets, where long-term fixed price contracts for the major cost and revenue components may be unavailable, which in turn may result in these projects having relatively high levels of volatility.

These projects can be capital-intensive and generally are designed with a view to obtaining third party financing, which may be difficult to obtain. As a result, these capital constraints may reduce our ability to develop these projects or obtain third party financing for these projects. These risks may be exacerbated by the current global economic crisis, including our management's increased focus on liquidity, which may also result in slower growth in the number of projects we can pursue. The economic downturn could also impact the value of our assets in these countries and our ability to develop these projects. If the value of these assets decline, this could result in a material impairment or a series of impairments which are material in the aggregate, which would adversely affect our financial statements.

Impairment of goodwill or long-lived assets would negatively impact our consolidated results of operations and net worth.

Goodwill represents the future economic benefits arising from assets acquired in a business combination (acquisition) that are not individually identified and separately recognized. Goodwill is not amortized, but is evaluated for impairment at least annually, or more frequently if impairment indicators are present. In evaluating the potential impairment of goodwill, we make estimates and assumptions about revenue, operating cash flows, capital expenditures, growth rates and discount rates based on our budgets and long term forecasts, macroeconomic projections, and current market expectations of returns on similar assets. There are inherent uncertainties related to these factors and management's judgment in applying these factors. Generally, the fair value of a reporting unit is determined using a discounted cash flow valuation model. We could be required to evaluate the potential impairment of goodwill outside of the required annual assessment process if we experience situations, including but not limited to: deterioration in general economic conditions, or our operating or regulatory environment; increased competitive environment; increase in fuel costs, particularly when we are unable to pass through the impact to customers; negative or declining cash flows; loss of a key contract or customer particularly when we are unable to replace it on equally favorable terms; divestiture of a significant component of our business; or adverse actions or assessments by a regulator. Additionally, goodwill may be impaired if our acquisitions do not perform as expected. See further discussion in *"Our Acquisitions May Not Perform as Expected."* These types of events and the resulting analyses could result in goodwill impairment expense, which could substantially affect our results of operations for those periods. As of December 31, 2011, we had $3.7 billion of goodwill, which represented approximately 8% of our total assets. If current global economic conditions deteriorate, as further described in Item 7.—*Management's*

Discussion and Analysis of Financial Condition and Results of Operations—Global Economic Conditions, it could increase the risk that we will have to recognize and record goodwill impairment charges.

Long-lived assets are initially recorded at fair value and are amortized or depreciated over their estimated useful lives. Long-lived assets are evaluated for impairment only when impairment indicators are present whereas goodwill is evaluated for impairment on an annual basis or more frequently if potential impairment indicators are present. Otherwise, the recoverability assessment of long-lived assets is similar to the potential impairment evaluation of goodwill particularly as it relates to the identification of potential impairment indicators, and making estimates and assumptions to determine fair value, as described above.

Certain of our businesses are sensitive to variations in weather.

Our businesses are affected by variations in general weather conditions and unusually severe weather. Our businesses forecast electric sales on the basis of normal weather, which represents a long-term historical average. While we also consider possible variations in normal weather patterns and potential impacts on our facilities and our businesses, there can be no assurance that such planning can prevent these impacts, which can adversely affect our business. Generally, demand for electricity peaks in winter and summer. Typically, when winters are warmer than expected and summers are cooler than expected, demand for energy is lower, resulting in less demand for electricity than forecasted. Significant variations from normal weather where our businesses are located could have a material impact on our results of operations.

In addition, we are dependent upon hydrological conditions prevailing from time to time in the broad geographic regions in which our hydroelectric generation facilities are located. If hydrological conditions result in droughts or other conditions that negatively affect our hydroelectric generation business, our results of operations could be materially adversely affected. In the past, our businesses in Latin America have been negatively impacted by lower than normal rainfall. Similarly, our wind businesses are dependent on adequate wind conditions while the solar projects at AES Solar are dependent on sufficient sunlight. In each case, inadequate wind or sunlight could have a material adverse impact on these businesses.

Information security breaches could harm our business.

A security breach of our information systems could impact the reliability of our generation fleets and/or the reliability of our transmission and distribution systems. A security breach that impairs our information technology infrastructure could disrupt normal business operations and affect our ability to control our transmission and distribution assets, access customer information and limit our communications with third parties. Our security measures may not prevent such security breaches. Any loss of confidential or proprietary data through a breach could impair our reputation, expose us to legal claims and materially adversely affect our business and results of operations.

Our acquisitions may not perform as expected.

Historically, acquisitions have been a significant part of our growth strategy. We may continue to grow our business through acquisitions. Although acquired businesses may have significant operating histories, we will have a limited or no history of owning and operating many of these businesses and possibly limited or no experience operating in the country or region where these businesses are located. Some of these businesses may have been government owned and some may be operated as part of a larger integrated utility prior to their acquisition. If we were to acquire any of these types of businesses, there can be no assurance that:

- we will be successful in transitioning them to private ownership;
- such businesses will perform as expected;
- integration or other one-time costs will not be greater than expected;

- we will not incur unforeseen obligations or liabilities;
- such businesses will generate sufficient cash flow to support the indebtedness incurred to acquire them or the capital expenditures needed to develop them; or
- the rate of return from such businesses will justify our decision to invest capital to acquire them.

In November 2011, we acquired DPL Inc., owner of DP&L. Risks associated with the acquisition of DPL are further discussed below.

We 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 or result in goodwill impairment.

The success of our recent acquisition of DPL will depend, in part, on our ability to realize the anticipated benefits and cost savings from integrating DPL into our portfolio of businesses. Our ability 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, including DPL's ability to achieve a successful outcome on its ESP or MRO proceeding and to manage customers' ability to select alternative electric generation providers (in each case, as described below);
- the possibility that the Company paid more than the value it will derive from the acquisition, which may lead to future impairments;
- 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 previously 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, which is moving towards a market-based pricing mechanism (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. In addition, under Ohio law, DPL will be required to provide a standard service officer ("SSO") through either an Electric Service Plan or Market Rate Offer which will be effective by January 1, 2013, the terms of which could have a material impact on our results of operations. Further information regarding these requirements is disclosed in Item 1. Business—Regulatory Matters—*United States*.

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. Under this legislation, customers can elect to buy transmission and generation service from a PUCO-certified Competitive Retail Electric Service Provider ("CRES Provider") offering services to customers in DP&L's service territory. Increased competition by unaffiliated CRES Providers in DP&L's service territory for retail generation service could result in the loss of existing customers and reduced revenues and increased costs to retain or attract customers. The following are a few of the factors that could result in increased switching by customers to PUCO-certified CRES Providers in the future:

- Low wholesale price levels may lead to existing CRES Providers becoming more active in our service territory, and additional CRES providers entering our territory.

- We could also experience customer switching through governmental aggregation, where a municipality may contract with a CRES Provider to provide generation service to the customers located within the municipal boundaries. Greater than expected customers switching would decrease DPL's margins 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, including goodwill impairment, and stock price.

The Company and DPL have operated and will continue to operate, independently. It is possible that the ongoing 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 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 ongoing integration of the businesses of the two companies and diverted from day-to-day business operations, which may disrupt each of the companies' ongoing businesses and the business of the combined company.

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

The Company has incurred and 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 has incurred and 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 ongoing 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 DPL acquisition 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.

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 earnings dilution. In addition, in connection with the acquisition, we recorded $2.5 billion in provisional goodwill. If we do not take actions that successfully mitigate and reduce the impacts of adverse changes in market conditions and if we do not realize the anticipated benefits of the transaction, it is possible that we may have to impair all or a portion of the goodwill, which could have a material impact in the periods in which the impairment occurs. 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. If incremental cash flow and dividends from operating subsidiaries of DPL are not sufficient to service the $3.3 billion of debt we incurred to fund the acquisition, 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.

Risks associated with Governmental Regulation and Laws

Our operations are subject to significant government regulation and our business and results of operations could be adversely affected by changes in the law or regulatory schemes.

Our inability to predict, influence or respond appropriately to changes in law or regulatory schemes, including any inability to obtain expected or contracted increases in electricity tariff rates or tariff adjustments for increased expenses, could adversely impact our results of operations or our ability to meet publicly announced projections or analysts' expectations. Furthermore, changes in laws or regulations or changes in the application or interpretation of regulatory provisions in jurisdictions where we operate, particularly our Utilities where electricity tariffs are subject to regulatory review or approval, could adversely affect our business, including, but not limited to:

- changes in the determination, definition or classification of costs to be included as reimbursable or pass-through costs to be included in the rates we charge our customers, including but not limited to costs incurred to upgrade our power plants to comply with more stringent environmental regulations;
- changes in the determination of what is an appropriate rate of return on invested capital or a determination that a utility's operating income or the rates it charges customers is too high, resulting in a reduction of rates or consumer rebates;
- changes in the definition or determination of controllable or non-controllable costs;
- adverse changes in tax law;
- changes in the definition of events which may or may not qualify as changes in economic equilibrium;
- changes in the timing of tariff increases;
- other changes in the regulatory determinations under the relevant concessions; or
- other changes related to licensing or permitting which affect our ability to conduct business.

Any of the above events may result in lower margins for the affected businesses, which can adversely affect our business.

In many countries where we conduct business, the regulatory environment is constantly changing or the regulations can be difficult to interpret. As a result, there is risk that we may not properly interpret certain regulations and may not understand the impact of certain regulations on our business. For example, in October 2006, ANEEL, which regulates our utility operations at Sul and Eletropaulo in Brazil, issued Normative Resolution 234 requiring that utilities begin amortizing a liability called "Special Obligations" beginning with their second tariff reset cycle in 2007 or a later year as an offset to depreciation expense. As of May 23, 2007, the date of the filing of our 2006 Form 10-K, no industry positions or any other consensus had been reached regarding how ANEEL guidance should be applied at that date and accordingly, no adjustments to the financial statements were made relating to Special Obligations in Brazil. Subsequent to May 23, 2007, industry discussions occurred and other Brazilian companies filed Forms 20-F with the SEC reflecting the impact of Resolution 234 in their December 31, 2006 financial statements differently from how the Company accounted for Resolution 234. In the absence of any significant regulatory developments between May 23, 2007 and the date of these other filings, the Company determined that Resolution 234 required us to record an adjustment to our Special Obligations liability as of December 31, 2006. In part, the decision to record the adjustment led to the restatement of our financial statements in the third quarter of 2007. If we face additional challenges interpreting regulations or changes in regulations, it could have a material adverse impact on our business.

On July 21, 2010, President Obama signed the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"). While the bulk of regulations contained in the Dodd-Frank Act regulate financial institutions and their products, there are several provisions related to corporate governance, executive compensation, disclosure and other matters which relate to public companies generally. The types of provisions described above are currently not expected to have a material impact on the Company or its results of operations. Furthermore, while the Dodd-Frank Act substantially expands the regulation regarding the trading, clearing and reporting of derivative transactions, the Dodd-Frank Act provides for commercial end-user exemptions which may apply to our derivative transactions, though this is not certain since the Act directs the SEC, CFTC and listed companies to enact rules that will clarify the Dodd-Frank Act, and such rulemaking could impact the availability of the commercial end-user exemption. Even if the exemption is available, the Dodd-Frank Act could still have a material adverse impact on the Company, as the regulation of derivatives (which includes capital and margin requirements for non-exempt companies), could limit the availability of derivative transactions that we use to reduce interest rate, commodity and currency risks, which would increase our exposure to these risks. Even if derivative transactions remain available, the costs to enter into these transactions may increase, which could adversely affect the operating results of certain projects; cause us to default on certain types of contracts where we are contractually obligated to hedge certain risks, such as project financing agreements; prevent us from developing new projects where interest rate hedging is required; cause the Company to abandon certain of its hedging strategies and transactions, thereby increasing our exposure to interest rate, commodity and currency risk; and/or consume substantial liquidity by forcing the Company to post cash and/or other permitted collateral in support of these derivatives. Any of these outcomes could have a material adverse effect on the Company.

On June 12, 2009 AES Kelanitissa received a letter and an invoice from the Director General, Public Utilities Commission of Sri Lanka (“PUC”) seeking payment of an Annual Regulatory Fee and pursuant to PUC assurances on an application for renewal of the AES Kelanitissa generation license. The application is pursuant to an April 2009 revision of the Sri Lanka Electricity Act (“Electricity Act”), which came into force in April 2009, notwithstanding that in March 29, 2001, AES Kelanitissa had been granted, and pre-paid fees for, a 21 year generation license with effect from September 25, 2000 under the Electricity Act, 1950. AES Kelanitissa submitted an application to be licensed under the revised legislation and, on August 26, 2009, PUC published its intention to issue a generation license under the revised legislation to AES Kelanitissa and other Independent Power Producers (“IPPs”) in Sri Lanka. This was consistent with assurances received from relevant authorities that the revised legislation was to be amended to grandfather IPPs with existing generation licenses. In a letter dated June 21, 2010 from the PUC, AES Kelanitissa was informed that under the new regulations, as amended in 2009, AES Kelanitissa (Pvt) Ltd no longer fulfilled the eligibility criteria to apply for a generation license. The “eligibility criteria” to which the letter refers is a provision requiring an element of state ownership. Representatives of AES Kelanitissa have been informed that an amendment to the Electricity Act to grandfather existing IPPs remains in the legislative pipeline, although it is not possible to predict with certainty when or whether such an amendment will be passed. In addition, AES Kelanitissa believes that under Sri Lankan law, it may continue operations under the 21 year license issued in 2001. No step has been taken to date to prohibit AES Kelanitissa from generating power and conducting its operations. However, in the event that it is determined that AES Kelanitissa may not operate under its current license or the revised legislation is not amended (and PUC maintains that AES Kelanitissa is ineligible for a generation license or extension of the Generating License), AES Kelanitissa may not be able to continue operations on grounds that it has no license under the revised legislation. In that event, AES Kelanitissa and/or the Company could face a number of adverse consequences, including potential litigation with counterparties mitigating a write down in the value of the assets of the business, continued default status under its debt documents and/or other consequences which could have a material impact on the Company or its results of operations.

Our Generation business in the United States is subject to the provisions of various laws and regulations administered in whole or in part by the FERC, including the Public Utility Regulatory Policies Act of 1978 (“PURPA”), the Federal Power Act, and the EPAct 2005. Actions by the FERC and by state utility commissions can have a material effect on our operations.

EPAct 2005 authorizes the FERC to remove the obligation of electric utilities under Section 210 of PURPA to enter into new contracts for the purchase or sale of electricity from or to QFs if certain market conditions are met. Pursuant to this authority, the FERC has instituted a rebuttable presumption that utilities located within the control areas of the Midwest Transmission System Operator, Inc., PJM ("Pennsylvania, New Jersey and Maryland") Interconnection, L.L.C., ISO New England, Inc., the New York Independent System Operator ("NYISO") and the Electric Reliability Council of Texas, Inc. are not required to purchase or sell power from or to QFs above a certain size. In addition, the FERC is authorized under the new law to remove the purchase/sale obligations of individual utilities on a case-by-case basis. While the new law does not affect existing contracts, as a result of the changes to PURPA, our QFs may face a more difficult market environment when their current long-term contracts expire.

EPAct 2005 repealed PUHCA 1935 and enacted PUHCA 2005 in its place. PUHCA 1935 had the effect of requiring utility holding companies to operate in geographically proximate regions and therefore limited the range of potential combinations and mergers among utilities. By comparison, PUHCA 2005 has no such restrictions and simply provides the FERC and state utility commissions with enhanced access to the books and records of certain utility holding companies. The repeal of PUHCA 1935 removed barriers to mergers and other potential combinations which could result in the creation of large, geographically dispersed utility holding companies. These entities may have enhanced financial strength and therefore an increased ability to compete with us in the United States generation market.

In accordance with Congressional mandates in the EPAct 1992 and now in EPAct 2005, the FERC has strongly encouraged competition in wholesale electric markets. Increased competition may have the effect of lowering our operating margins. Among other steps, the FERC has encouraged RTOs and ISOs to develop demand response bidding programs as a mechanism for responding to peak electric demand. These programs may reduce the value of our peaking assets which rely on very high prices during a relatively small number of hours to recover their costs. Similarly, the FERC is encouraging the construction of new transmission infrastructure in accordance with provisions of EPAct 2005. Although new transmission lines may increase market opportunities, they may also increase the competition in our existing markets.

While the FERC continues to promote competition, some state utility commissions have reversed course and begun to encourage the construction of generation facilities by traditional utilities to be paid for on a cost-of-service basis by retail ratepayers. Such actions have the effect of reducing sale opportunities in the competitive wholesale generating markets in which we operate.

Our businesses are subject to stringent environmental laws and regulations.

Our activities are subject to stringent environmental laws and regulations by many federal, regional, state and local authorities, international treaties and foreign governmental authorities. These laws and regulations generally concern emissions into the air, effluents into the water, use of water, wetlands preservation, remediation of contamination, waste disposal, endangered species and noise regulation, among others. Failure to comply with such laws and regulations or to obtain or comply with any necessary environmental permits pursuant to such laws and regulations could result in fines or other sanctions. Environmental laws and regulations affecting power generation and distribution are complex and have tended to become more stringent over time. Congress and other domestic and foreign governmental authorities have either considered or implemented various laws and regulations to restrict or tax certain emissions, particularly those involving air emissions and water discharges. See the various descriptions of these laws and regulations contained in Item 1.—Business—*Regulatory Matters* of this Form 10-K. These laws and regulations have imposed, and proposed laws and regulations could impose in the future, additional costs on the operation of our power plants. We have incurred and will continue to incur significant capital and other expenditures to comply with these and other environmental laws and regulations. Changes in, or new, environmental restrictions may force the Company to incur significant expenses or expenses that may exceed our estimates. There can be no assurance that we would be able to recover all or any increased environmental costs from our customers or that our business, financial condition, including recorded asset values or results of operations would not be materially and adversely affected by such expenditures or any changes in domestic or foreign environmental laws and regulations.

Our businesses are subject to enforcement initiatives from environmental regulatory agencies.

The EPA has pursued an enforcement initiative against coal-fired generating plants alleging wide-spread violations of the new source review and prevention of significant deterioration provisions of the CAA. The EPA has brought suit against a number of companies and has obtained settlements with approximately 23 companies over such allegations. The allegations typically involve claims that a company made major modifications to a coal-fired generating unit without proper permit approval and without installing best available control technology. The principal, but not exclusive, focus of this EPA enforcement initiative is emissions of SO_2 and NO_X. In connection with this enforcement initiative, the EPA has imposed fines and required companies to install improved pollution control technologies to reduce emissions of SO_2 and NO_X. One of our U.S. utility businesses, IPL, is currently the subject of such EPA enforcement action. See Item 3.—Legal Proceedings of this Form 10-K for more detail with respect to these EPA enforcement actions. There can be no assurance that foreign environmental regulatory agencies in countries in which our subsidiaries operate will not pursue similar enforcement initiatives under relevant laws and regulations.

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.

As discussed in Item 1.—Business—Regulatory Matters—*Environmental and Land Use Regulations*, at the international, federal and various regional and state levels, rules are in effect or policies are under development to regulate GHG emissions, thereby effectively putting a cost on such emissions in order to create financial incentives to reduce them. In 2011, the Company's subsidiaries operated businesses which had total CO_2 emissions of approximately 74 million metric tonnes, approximately 37.5 million of which were emitted by businesses located in the United States (both figures ownership adjusted). The Company uses CO_2 emission estimation methodologies supported by "The Greenhouse Gas Protocol" reporting standard on GHG emissions. For existing power generation plants, CO_2 emissions are either obtained directly from plant continuous emission monitoring systems or calculated from actual fuel heat inputs and fuel type CO_2 emission factors. The estimated annual CO_2 emissions from fossil fuel electric power generation facilities of the Company's subsidiaries that are in construction or development and have received the necessary air permits for commercial operations are approximately 15.5 million metric tonnes (ownership adjusted). This overall estimate is based on a number of projections and assumptions which may prove to be incorrect, such as the forecasted dispatch, anticipated plant efficiency, fuel type, CO_2 emissions rates and our subsidiaries' achieving completion of such construction and development projects. However, it is certain that the projects under construction or development when completed will increase emissions of our portfolio and therefore could increase the risks associated with emissions described below. Because there is significant uncertainty regarding these estimates, actual emissions from these projects under construction or development may vary substantially from these estimates.

The non-utility, generation subsidiaries of the Company often seek to pass on any costs arising from CO_2 emissions to contract counterparties, but there can be no assurance that such subsidiaries of the Company will effectively pass such costs onto the contract counterparties or that the cost and burden associated with any dispute over which party bears such costs would not be burdensome and costly to the relevant subsidiaries of the Company. The utility subsidiaries of the Company may seek to pass on any costs arising from CO_2 emissions to customers, but there can be no assurance that such subsidiaries of the Company will effectively pass such costs to the customers, or that they will be able to fully or timely recover such costs.

Foreign, federal, state or regional regulation of GHG emissions could have a material adverse impact on the Company's financial performance. The actual impact on the Company's financial performance and the financial performance of the Company's subsidiaries will depend on a number of factors, including among others, the degree and timing of GHG emissions reductions required under any such legislation or regulations, the cost of emissions reduction equipment and the price and availability of offsets, the extent to which market based compliance options are available, the extent to which our subsidiaries would be entitled to receive GHG emissions allowances without having to purchase them in an auction or on the open market and the impact of such legislation or regulation on the ability of our subsidiaries to recover costs incurred through rate increases or otherwise. As a result of these factors, our cost of compliance could be substantial and could have a material impact on our results of operations.

In January 2005, based on European Community "Directive 2003/87/EC on Greenhouse Gas Emission Allowance Trading," the European Union Greenhouse Gas Emission Trading Scheme ("EU ETS") commenced operation as the largest multi-country GHG emission trading scheme in the world. On February 16, 2005, the Kyoto Protocol became effective. The Kyoto Protocol requires all developed countries that have ratified it to substantially reduce their GHG emissions, including CO_2. To date, compliance with the Kyoto Protocol and the EU ETS has not had a material adverse effect on the Company's consolidated results of operations, financial condition and cash flows.

The United States has not ratified the Kyoto Protocol. In the United States, there currently are no federal laws imposing a mandatory GHG emission reduction programs (including for CO_2) affecting the electric power generation facilities of the Company's subsidiaries. However, federal GHG legislation was previously proposed in the United States Congress that, if it had been enacted, would have constrained GHG emissions, including CO_2, and/or imposed costs on the Company that could have been material to our business or results of operations. Although there currently is no federal GHG legislation, the EPA has adopted regulations pertaining to GHG emissions that require new sources of GHG emissions of over 100,000 tons per year, and existing sources planning physical changes that would increase their GHG emissions by more than 75,000 tons per year, to obtain new source review permits from the EPA prior to construction or modification.

Such regulations could increase our costs directly and indirectly and have a material adverse effect on our business and/or results of operations. See Item 1. Business—Regulatory Matters—*Environmental and Land Use Regulations* of this Form 10-K for further discussion about these environmental agreements, laws and regulations.

At the state level, RGGI, a cap-and-trade program covering CO_2 emissions from electric power generation facilities in the Northeast, became effective in January 2009, and California has adopted comprehensive legislation that will require mandatory GHG reductions from several industrial sectors, including the electric power generation industry. See Item 1.—Business—Regulatory Matters—*Environmental and Land Use Regulations* of this Form 10-K for further discussion about the United States state environmental regulations we face. At this time, other than with regard to RGGI (further described below), the Company cannot estimate the costs of compliance with United States federal, regional or state CO_2 emissions reduction legislation or initiatives, due to the fact that most of these proposals are not being actively pursued or are in the early stages of development and any final regulations or laws, if adopted, could vary drastically from current proposals, or in the case of California, due to the fact that we anticipate such costs will be passed through to our offtakers under the terms of existing tolling agreements.

The RGGI program became effective in January 2009. The first regional auction of RGGI allowances needed to be acquired by power generators to comply with state programs implementing RGGI was held in September 2008, with subsequent auctions occurring approximately every quarter. Our subsidiary in Maryland is our only subsidiary subject to RGGI in 2012. Of the approximately 37.5 million metric tonnes of CO_2 emitted in the United States by our subsidiaries in 2011 (ownership adjusted), approximately 8.3 million metric tonnes were affected by RGGI requirements. Over the past three years, such emissions have averaged approximately 9.8 million metric tonnes. While CO_2 emissions from businesses operated by subsidiaries of the Company are calculated globally in metric tonnes, RGGI allowances are denominated in short tons. (1 metric tonne equals 2,200 pounds and 1 short ton equals 2,000 pounds.) For forecasting purposes, the Company has modeled the impact of CO_2 compliance based on a 3-year average of CO_2 emissions for its businesses that are subject to RGGI and that may not be able to pass through compliance costs. The model includes a conversion from metric tonnes to short tons as well as the impact of some market recovery by merchant plants and contractual and regulatory provisions. The model also utilizes a price of $1.89 per allowance under RGGI. The source of this allowance price estimate was the clearing price in the recent RGGI allowance auction held in December 2011. Based on these assumptions, the Company estimates that the RGGI compliance costs could be approximately $2.8 million for 2012. Given the fact that the assumptions utilized in the model may prove to be incorrect, there is a significant risk that our actual compliance costs under RGGI will differ from our estimates by a material amount and that our model could underestimate our costs of compliance.

In addition to government regulators, other groups such as politicians, environmentalists and other private parties have expressed increasing concern about GHG emissions. For example, certain financial institutions have expressed concern about providing financing for facilities which would emit GHGs, which can affect our ability to obtain capital, or if we can obtain capital, to receive it on commercially viable terms. Further, rating agencies may decide to downgrade our credit ratings based on the emissions of the businesses operated by our subsidiaries or increased compliance costs which could make financing unattractive. In addition, plaintiffs have brought tort lawsuits against the Company because of its subsidiaries' GHG emissions. Unless the United States Congress acts to preempt such suits as part of comprehensive federal legislation, additional lawsuits may be brought against the Company or its subsidiaries in the future. At this stage of the litigation, it is impossible to predict whether such lawsuits are likely to prevail or result in damages awards or other relief. Consequently, it is impossible to determine whether such lawsuits are likely to have a material adverse effect on the Company's consolidated results of operations and financial condition.

Furthermore, according to the Intergovernmental Panel on Climate Change, physical risks from climate change could include, but are not limited to, increased runoff and earlier spring peak discharge in many glacier and snow-fed rivers, warming of lakes and rivers, an increase in sea level, changes and variability in precipitation and in the intensity and frequency of extreme weather events. Physical impacts may have the potential to significantly affect the Company's business and operations, and any such potential impact may render it more difficult for our businesses to obtain financing. For example, extreme weather events could result in increased downtime and operation and maintenance costs at the electric power generation facilities and support facilities of the Company's subsidiaries. Variations in weather conditions, primarily temperature and humidity also would be expected to affect the energy needs of customers. A decrease in energy consumption could decrease the revenues of the Company's subsidiaries. In addition, while revenues would be expected to increase if the energy consumption of customers increased, such increase could prompt the need for additional investment in generation capacity. Changes in the temperature of lakes and rivers and changes in precipitation that result in drought could adversely affect the operations of the fossil fuel-fired electric power generation facilities of the Company's subsidiaries. Changes in temperature, precipitation and snow pack conditions also could affect the amount and timing of hydroelectric generation.

In addition to potential physical risks noted by the Intergovernmental Panel on Climate Change, there could be damage to the reputation of the Company and its subsidiaries due to public perception of GHG emissions by the Company's subsidiaries, and any such negative public perception or concerns could ultimately result in a decreased demand for electric power generation or distribution from our subsidiaries. The level of GHG emissions made by subsidiaries of the Company is not a factor in the compensation of executives of the Company.

If any of the foregoing risks materialize, costs may increase or revenues may decrease and there could be a material adverse effect on the electric power generation businesses of the Company's subsidiaries and on the Company's consolidated results of operations, financial condition and cash flows.

Tax legislation initiatives or challenges to our tax positions could adversely affect our results of operations and financial condition.

Our subsidiaries have operations in the United States and various non-United States jurisdictions. As such, we are subject to the tax laws and regulations of the United States federal, state and local governments and of many non-United States jurisdictions. From time to time, legislative measures may be enacted that could adversely affect our overall tax positions. There can be no assurance that our effective tax rate or tax payments will not be adversely affected by these initiatives. In addition, United States federal, state and local, as well as non-United States, tax laws and regulations are extremely complex and subject to varying interpretations. There can be no assurance that our tax positions will be sustained if challenged by relevant tax authorities.

We and our affiliates are subject to material litigation and regulatory proceedings.

We and our affiliates are parties to material litigation and regulatory proceedings. See Item 3.—Legal Proceedings below. There can be no assurances that the outcome of such matters will not have a material adverse effect on our consolidated financial position.

The SEC is conducting an informal inquiry relating to our restatements.

We have been cooperating with an informal inquiry by the SEC Staff concerning our past restatements and related matters, and have been providing information and documents to the SEC Staff on a voluntary basis. Although we have not received correspondence regarding this inquiry for some time, we have not been advised that the matter is closed. Because we are unable to predict the outcome of this inquiry, the SEC Staff may disagree with the manner in which we have accounted for and reported the financial impact of the adjustments to previously filed financial statements and there may be a risk that the inquiry by the SEC could lead to circumstances in which we may have to further restate previously filed financial statements, amend prior filings or take other actions not currently contemplated.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

We maintain offices in many places around the world, generally pursuant to the provisions of long- and short-term leases, none of which we believe are material. With a few exceptions, our facilities, which are described in Item 1 of this Form 10-K, are subject to mortgages or other liens or encumbrances as part of the project's related finance facility. In addition, the majority of our facilities are located on land that is leased. However, in a few instances, no accompanying project financing exists for the facility, and in a few of these cases, the land interest may not be subject to any encumbrance and is owned outright by the subsidiary or affiliate.

ITEM 3. LEGAL PROCEEDINGS

The Company is involved in certain claims, suits and legal proceedings in the normal course of its business. 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 December 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$1.2 billion ($644 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. The parties are briefing the issues. 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 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 seeking 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. ("OPGC"), an equity method investment of the Company, 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. In November 2011, the Indian court rejected Gridco's June 2008 application for injunctive relief. 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 PPA's 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, and the Public Attorney’s office no longer 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 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 ($3 million). The injunction was rejected and the case is in the evidentiary state awaiting the production of the court’s expert opinion. However, in October 2011, the State Prosecution Office presented a new request to the court of Triunfo for an injunction against Florestal, Sul and CEEE for the removal of the alleged sources of contamination and remediation, and the court granted the injunction against CEEE but did not grant injunctive relief against Florestal or Sul. CEEE appealed such decision, but failed to stay it. The appeal is pending judgment by the State of Rio Grande do Sul Court of Appeals. The above-referenced proposal to FEPAM with respect to containing and remediating the contamination 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 ($8 million).

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 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 ($124 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 and second panels) and the Kazakhstan Supreme Court were unsuccessful. 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.

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”), for the period from 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 from 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 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 Ninth Circuit heard oral arguments on November 28, 2011, and thereafter took the appeal under consideration. 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 (the Environmental Agency of Sao Paulo State) 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$760 million ($408 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 filed appeals to both the Superior Court of Justice and the Supreme Court 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 ($537 thousand) as of June 30, 2011, or pay an indemnification amount of approximately R$11 million ($6 million). Eletropaulo has appealed this decision to the Supreme Court and is awaiting a decision.

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 took place in December 2011, and thereafter the arbitrators took those issues under consideration. AESU believes it has meritorious claims and defenses and will assert them vigorously; however, there can be no assurances that it will be successful in its efforts.

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 ($26 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 $678,000) for the allowances granted for free for 2007 and €19,907,248 (approximately $26 million) for 2008. In July 2010, AES Cartagena received an invoice for approximately €5 million ($6 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 S.A. ("GDFS"), in relation to the CNE invoices under the long-term energy agreement (the "Energy Agreement") with GDFS. However, GDFS has disputed that it is responsible for the CNE invoices under the Energy Agreement. Therefore, in September 2009, AES Cartagena initiated arbitration against GDFS, seeking to recover the payments made to CNE. In the arbitration, AES Cartagena also seeks a determination that GDFS 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 ($32 million) for the CO_2 allowances that have been required to offset 2008, 2009 and 2010 CO_2 emissions. AES Cartagena does not need to purchase allowances to offset 2011 emissions but may need to purchase allowances in the future. 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. In February 2012, the parties settled the dispute pursuant to the closing of a share sale agreement. See Note 28—*Subsequent Events* for further information.

In October 2009, IPL received a Notice of Violation ("NOV") and Finding of Violation from the EPA pursuant to the CAA Section 113(a). The NOV alleges violations of the CAA at IPL's three primarily coal-fired electric generating facilities dating back to 1986. The alleged violations primarily pertain to the 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 regarding possible resolutions of the 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, install additional pollution control technology on coal-fired electric generating units, retire existing generating units, and invest in additional environmental projects. 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 of any operating or capital expenditures related to air pollution control technology 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, April 2011, June 2011, August 2011, and November 2011, substantially similar personal injury lawsuits were filed by a total of 49 residents and decedent 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 from October 2003 through March 2004 and subsequently caused the plaintiffs' birth defects, other personal injuries, and/or deaths. The plaintiffs did not quantify their alleged damages, but generally alleged that they are entitled to compensatory and punitive damages. The AES defendants moved for partial dismissal of both the November 2009 and April 2010 lawsuits on various grounds. In July 2011, the Superior Court dismissed the plaintiffs' international law and punitive damages claims, but held that the plaintiffs had stated intentional tort, negligence, and strict liability claims under Dominican law, which the Superior Court found governed the lawsuits. The Superior Court granted the plaintiffs leave to amend their complaints in accordance with its decision, and in September 2011, the plaintiffs in the November 2009 and April 2010 lawsuits did so. The AES defendants have moved for partial dismissal of those amended complaints. After the motions are decided, the AES defendants will answer the November 2009 lawsuit. The parties have requested that the Superior Court stay the remaining six lawsuits, as well as any subsequently filed similar lawsuits, while the parties undertake discovery on causation issues in the November 2009 lawsuit. The AES defendants believe they have meritorious defenses 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 a 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 was approximately €155 million ($201 million). The Contractor obtained an injunction from a lower French court purportedly preventing the issuing bank from honoring the bond demands. However, the Versailles Court of Appeal canceled the injunction in July 2011, and therefore the issuing bank paid the bond demands in full. The Contractor may attempt to seek relief relating to the bond dispute in the English courts. In addition, in December 2010, the Contractor stopped commissioning of the power plant's two units because of the alleged characteristics of the lignite supplied to it for commissioning. In January 2011, the Contractor initiated arbitration on its lignite claim, seeking an extension of time to complete the power plant, an increase to the contract price, and other relief, including in relation to the bond demands. The Contractor later added claims relating to the alleged unavailability of the grid during commissioning. Maritza 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 also terminated the EPC Contract for cause and asserted arbitration claims against the Contractor relating to the termination. The Contractor asserted counterclaims relating to the termination. The Contractor is seeking approximately €240 million ($311 million) in the arbitration, unspecified damages for alleged injury to reputation, and other relief. The arbitral hearing on the merits is in September 2012. 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 million ($561,375) and the suspension of AES Eletropaulo activities in the Park. As a response to this administrative procedure before the São Paulo State Environmental Authorities ("Sao Paulo EA"), AES Eletropaulo timely presented its defense on February 28, 2011 seeking to vacate the notice of violation or reduce the fine. In December 2011, the Sao Paulo EA declined to vacate the notice of violation but recognized the possibility of 40% reduction in the fine if AES Eletropaulo agrees to recover the affected area with additional vegetation. AES Eletropaulo has not appealed the decision and is now discussing the terms of a possible settlement with the Sao Paulo EA.

Purported stockholders of DPL filed nine putative derivative and/or class actions in Ohio state court and three such suits in Ohio federal court against DPL and its board of directors relating to DPL's agreement to merge with the Company. Most of those lawsuits name the Company as a defendant. The lawsuits are substantially similar and allege that the price offered in the merger is unfair, DPL's directors breached their fiduciary duty by agreeing to the merger at an unfair price, and the Company aided and abetted that breach by offering an unfair price. The lawsuits seek to enjoin the merger and some suits also seek unspecified damages. Five of the state lawsuits have been voluntarily dismissed without prejudice. The defendants' motions to dismiss the remaining four state lawsuits are pending. The three federal lawsuits were consolidated, and the plaintiffs in those suits filed a consolidated amended complaint asserting state and federal disclosure claims and moved to enjoin the merger prior to the vote of DPL's shareholders on the merger. The defendants filed motions to dismiss the consolidated amended complaint. The federal court established a briefing schedule on those motions and ordered limited discovery on certain disclosure claims. Subsequently, in July 2011, the defendants and the federal plaintiffs executed a memorandum of understanding providing for the settlement of the litigation, subject to certain confirmatory discovery and court approval, pursuant to which DPL would make certain additional disclosures to stockholders in its final proxy statement prior to the shareholder vote on the merger. After execution of the MOU, the federal court suspended briefing on the motions pending before it. DPL made the additional disclosures required under the MOU. The shareholders of DPL later approved the merger in September 2011 and the merger was consummated in November 2011. The parties to the federal litigation filed a stipulation of settlement, subject to the federal court approval, that sought to dismiss the federal litigation with prejudice and release all claims by DPL stockholders concerning the merger. On February 23, 2012, at a settlement hearing, the federal court approved the stipulation of settlement and dismissed the federal litigation with prejudice. The Company believes it has meritorious defenses in the remaining state court actions and will assert these defenses vigorously; however, there can be no assurances that it will be successful in its efforts.

In May 2011, a putative class action was filed in the Mississippi federal court against the Company and numerous unrelated companies. The lawsuit alleges that greenhouse gas emissions contributed to alleged global warming which, in turn, allegedly increased the destructive capacity of Hurricane Katrina. The plaintiffs assert claims for public and private nuisance, trespass, negligence, and declaratory judgment. The plaintiffs seek damages relating to loss of property, loss of business, clean-up costs, personal injuries and death, but do not quantify their alleged damages. These and other plaintiffs previously brought a substantially similar lawsuit in the federal court but failed to obtain relief. In October 2011, the Company and other defendants filed motions to dismiss the lawsuit, which the plaintiffs have opposed. The Company believes it has meritorious defenses and will defend itself vigorously in this lawsuit; however, there can be no assurances that it will be successful in its efforts.

In June 2011, the São Paulo Municipal Tax Authority filed 60 tax assessments in São Paulo administrative court against Eletropaulo, seeking approximately R$1.2 billion ($644 million) in services tax ("ISS") that allegedly had not been collected on revenues from services rendered by Eletropaulo. Eletropaulo has defended on the ground that the revenues at issue were not subject to ISS. Eletropaulo believes it has meritorious defenses to the assessments and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In June 2011, the Supreme Court rejected federal common law nuisance claims initially brought in 2004 by eight states, the City of New York, and three land trusts, which sought injunctive relief and limitations on the GHG emissions of American Electric Power Company, Inc. ("AEP"), one of AEP's subsidiaries, Cinergy Corp. (a subsidiary of Duke Energy Corporation ("Duke Energy")), and four other electric power companies. The Supreme Court remanded the lawsuit for consideration of the plaintiffs' state law claims. Although it is not named as a party to this lawsuit, DP&L is a co-owner of coal-fired plants with Duke Energy and AEP (or their subsidiaries), which could be affected by the outcome of this lawsuit. DP&L believes that there are meritorious defenses to the plaintiffs' claims; however, there can be no assurances that the defendants will prevail in this lawsuit.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Recent Sales of Unregistered Securities

None.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

In July 2010, the Company's Board of Directors approved a stock repurchase program (the "Program") under which the Company can 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. There can be no assurances as to the amount, timing or prices of repurchases, which may vary based on market conditions and other factors. The Program does not have an expiration date and can be modified or terminated by the Board of Directors at any time. During the year ended December 31, 2011, shares of common stock repurchased under this plan totaled 25,541,980 at a total cost of $279 million plus a nominal amount of commissions (average of $10.93 per share including commissions), bringing the cumulative total purchases under the program to 33,924,805 shares at a total cost of $378 million plus a nominal amount of commissions (average of $11.16 per share including commissions).

The following table presents information regarding purchases made by The AES Corporation of its common stock in the fourth 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
10/1/11—10/31/11	5,554,185	$9.78	5,554,185	$122,158,079
11/1/11—11/30/11	—	$ —	—	$122,158,079
12/1/11—12/31/11	—	$ —	—	$122,158,079
Total	5,554,185	$9.78	5,554,185	

Market Information

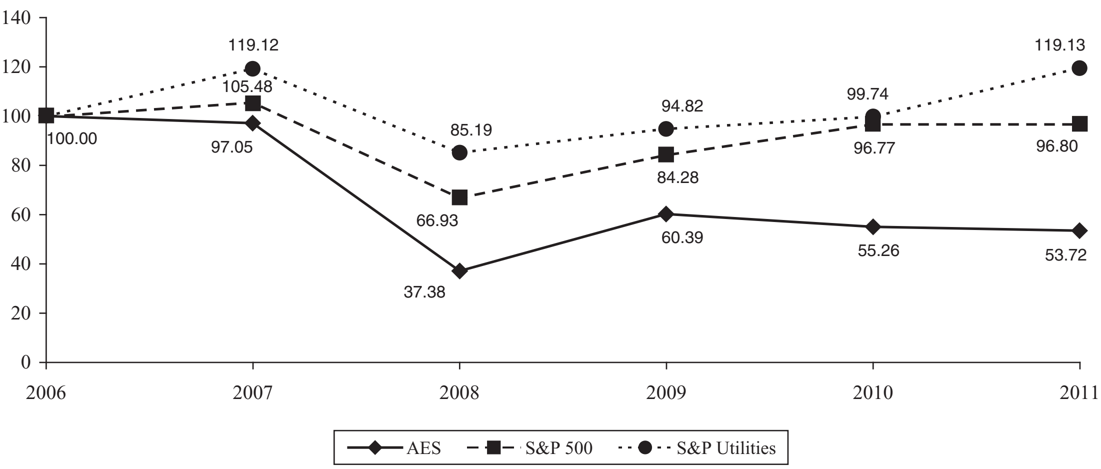
Our common stock is currently traded on the New York Stock Exchange ("NYSE") under the symbol "AES." The closing price of our common stock as reported by the NYSE on February 17, 2012, was $13.70, per share. The Company repurchased 25,541,980 and 8,382,825 shares of its common stock in 2011 and 2010, respectively, and did not repurchase any of its common stock in 2009. The following tables set forth the high and low sale prices, and performance trends for our common stock as reported by the NYSE for the periods indicated:

	2011		2010	
Price Range of Common Stock	High	Low	High	Low
First Quarter	$13.40	$11.99	$14.24	$10.73
Second Quarter	13.50	12.03	12.46	8.94
Third Quarter	13.20	9.22	11.57	8.82
Fourth Quarter	12.24	9.00	12.54	10.70

Performance Graph

THE AES CORPORATION
PEER GROUP INDEX/STOCK PRICE PERFORMANCE

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURNS
ASSUMES INITIAL INVESTMENT OF $100



Source: Bloomberg

We have selected the Standard and Poor's ("S&P") 500 Utilities Index as our peer group index. The S&P 500 Utilities Index is a published sector index comprising the 32 electric and gas utilities included in the S&P 500.

The five year total return chart assumes $100 invested on December 31, 2006 in AES Common Stock, the S&P 500 Index and the S&P 500 Utilities Index. The information included under the heading "Performance Graph" shall not be considered "filed" for purposes of Section 18 of the Securities Exchange Act of 1934 or incorporated by reference in any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934.

Holders

As of February 17, 2012, there were approximately 7,068 record holders of our common stock.

Dividends

We do not currently pay dividends on our common stock. We have announced our current intention to pay a cash dividend beginning in the fourth quarter of 2012. There can be no assurance that the AES Board will declare the dividend or, if declared, the amount of any dividend.

Under the terms of our senior secured credit facility, which we entered into with a commercial bank syndicate, we have limitations on our ability to pay cash dividends and/or repurchase stock.

Our project subsidiaries' ability to declare and pay cash dividends to us is subject to certain limitations contained in the project loans, governmental provisions and other agreements to which our project subsidiaries are subject.

See the information contained under Item 12.—*Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*, *Securities Authorized for Issuance under Equity Compensation Plans* of this Form 10-K.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth our selected financial data as of the dates and for the periods indicated. You should read this data together with Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations and the Consolidated Financial Statements and the notes thereto included in Item 8 of this Form 10-K. The selected financial data for each of the years in the five year period ended December 31, 2011 have been derived from our audited Consolidated Financial Statements. Prior period amounts have been restated to reflect discontinued operations in all periods presented. Our historical results are not necessarily indicative of our future results.

Acquisitions, disposals, reclassifications and changes in accounting principles affect the comparability of information included in the tables below. Please refer to the Notes to the Consolidated Financial Statements included in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further explanation of the effect of such activities. Please also refer to Item 1A.—Risk Factors and Note 25—Risks and Uncertainties to the Consolidated Financial Statements included in Item 8 of this Form 10-K for certain risks and uncertainties that may cause the data reflected herein not to be indicative of our future financial condition or results of operations.

SELECTED FINANCIAL DATA

Statement of Operations Data	Year Ended December 31, 2011[1]	2010	2009	2008	2007
	(in millions, except per share amounts)				
Revenue	$17,274	$15,828	$13,110	$14,171	$11,872
Income from continuing operations[2]	1,541	1,470	1,804	1,835	564
Income from continuing operations attributable to The AES Corporation, net of tax	458	484	724	1,092	184
Discontinued operations, net of tax	(400)	(475)	(66)	142	(279)
Net income (loss) attributable to The AES Corporation	$ 58	$ 9	$ 658	$ 1,234	$ (95)
Basic (loss) earnings per share:					
Income from continuing operations attributable to The AES Corporation, net of tax	$ 0.59	$ 0.63	$ 1.09	$ 1.63	$ 0.28
Discontinued operations, net of tax	(0.52)	(0.62)	(0.10)	0.21	(0.42)
Basic earnings (loss) per share	$ 0.07	$ 0.01	$ 0.99	$ 1.84	$ (0.14)
Diluted (loss) earnings per share:					
Income from continuing operations attributable to The AES Corporation, net of tax	$ 0.59	$ 0.63	$ 1.08	$ 1.62	$ 0.27
Discontinued operations, net of tax	(0.52)	(0.62)	(0.10)	0.20	(0.41)
Diluted earnings (loss) per share	$ 0.07	$ 0.01	$ 0.98	$ 1.82	$ (0.14)

Balance Sheet Data:	December 31, 2011[1]	2010	2009	2008	2007
	(in millions)				
Total assets	$45,333	$40,511	$39,535	$34,806	$34,453
Non-recourse debt (long-term)	$13,936	$11,643	$12,118	$11,056	$10,413
Non-recourse debt (long-term)—Discontinued operations	$ 674	$ 901	$ 746	$ 813	$ 917
Recourse debt (long-term)	$ 6,180	$ 4,149	$ 5,301	$ 4,994	$ 5,332
Cumulative preferred stock of a subsidiary	$ 78	$ 60	$ 60	$ 60	$ 60
Retained earnings (accumulated deficit)	$ 678	$ 620	$ 650	$ (8)	$ (1,241)
The AES Corporation stockholders' equity	$ 5,946	$ 6,473	$ 4,675	$ 3,669	$ 3,164

(1) DPL was acquired on November 28, 2011 and its results of operations have been included in AES' consolidated results of operations from the date of acquisition. See Note 23—*Acquisitions and Dispositions* to the Consolidated Financial Statements included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

(2) Includes pretax impairment expense of $242 million, $410 million, $142 million, $175 million and $408 million for the years ended December 31, 2011, 2010, 2009, 2008 and 2007, respectively.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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, generate and sell electricity on the wholesale market. For the year ended December 31, 2011, our Generation and Utilities businesses comprised approximately 45% and 55% of our consolidated revenue, respectively. For additional information regarding our business, see Item 1.—Business of this Form 10-K.

Our wind and solar businesses are not material contributors to our operating results. For additional information regarding our business, see Item 1.—Business of this Form 10-K.

Our Organization and Segments. The Company's current 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"). The financial reporting segment structure uses the Company's management reporting structure as its foundation and reflects how the Company manages the business internally. In October 2011, the Company announced a plan to redefine its operational management and organizational structure. The reporting structure will remain organized along two lines of business—Generation and Utilities, each led by a Chief Operating Officer; however, we are continuing to evaluate both the timing and impact, if any, that the realignment will have on our reportable segments. For the year ended December 31, 2011, 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; and
- Asia—Generation.

Corporate and Other. The Company's Europe Utilities, Africa Utilities, Africa Generation, Wind Generation operating segments and climate solutions and other renewables projects 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 production of energy from our generation plants, which are classified as regulated and non-regulated on the Consolidated Statements of Operations, respectively. Revenue also includes the gains or losses on derivatives (including embedded derivatives other than foreign currency embedded derivatives) associated with the sale of electricity. 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 and 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. 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 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 this 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 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 this 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 7A.—Quantitative and Qualitative Disclosures About Market Risk of this Form 10-K.

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 this 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 year ended December 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 and to integrate acquisitions. We currently have approximately 2,391 MW of projects under construction in nine countries. Our prospects for increased 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 this 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. Similarly, failure to integrate acquisitions and manage market risk, including the Company's recent acquisition of DPL, could impact our future operating results as disclosed in Item 1A.—Risk Factors of this Form 10-K, "*After completion of the DPL 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*" and *Key Trends and Uncertainties—Goodwill*, below.

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 GHG emissions, could substantially increase our capital expenditures or other compliance costs, which could in turn have a material adverse effect on our business and results of operations. For a further discussion of the Regulatory Environment, see Item 1.—Business—*Regulatory Matters—Environmental and Land Use Regulations* and Item 1A.—Risk Factors—*Risks Associated with Government Regulation and Laws* of this Form 10-K.

Management's Priorities

Management has re-evaluated its priorities following the appointment of its new CEO in September 2011. Management is focused on the following priorities:

- Execution of our geographic concentration strategy to maximize shareholder value through disciplined capital allocation including:
  - platform expansion in Brazil, Chile, Colombia, and the United States,
  - platform development in Turkey, Poland, and the United Kingdom,
  - corporate debt reduction, and
  - a return of capital to shareholders, including our intent to initiate a dividend in 2012;
- Closing the sales of businesses for which we have signed agreements with counterparties and prudently exiting select non-strategic markets;
- Optimizing profitability of operations in the existing portfolio;
- Integration of DPL into our portfolio;
- Implementing a management realignment of our businesses under two business lines: Utilities and Generation, and achieving cost savings through the alignment of overhead costs with business requirements, systems automation and optimal allocation of business development spending; and
- Completion of an approximately 2,400 MW construction program and the integration of new projects into existing businesses. During the year ended December 31, 2011, the following projects commenced commercial operations:

Project	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)
AES Solar[(1)]	Various	Solar	62	50%
Angamos	Chile	Coal	545	71%
Changuinola	Panama	Hydro	223	100%
Kumkoy[(2)]	Turkey	Hydro	18	51%
Laurel Mountain	US-WV	Wind	98	100%
Maritza	Bulgaria	Coal	670	100%
Sao Joaquim	Brazil	Hydro	3	24%
Trinidad[(3)]	Trinidad	Gas	394	10%

(1) AES Solar Energy Ltd. is a Joint Venture with Riverstone Holdings and is accounted for as an equity method investment. Plants that came online during the year include: Kalipetrovo, Ugento, Soemina, Francavilla Fontana, Latina, Cocomeri, Francofonte, Scopeto, Sabaudia, Aprilla-1, Siracusa 1-3 Complex, Manduria Apollo and Rinaldone.

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

(3) An equity method investment held by AES.

Key Trends and Uncertainties

Our operations continue to face many risks as discussed in Item 1A.—Risk Factors of this Form 10-K. Some of these challenges are also described below in "*Key Drivers of Results in 2011*". We continue to monitor our operations and address challenges as they arise.

Operations

In August 2010, the Esti power plant, a 120 MW run-of-river hydroelectric power plant in Panama, was taken offline due to damage to its tunnel infrastructure. AES Panama is partially covered for business interruption losses and property damage under existing insurance programs. The Esti power plant is currently being repaired and is projected to resume operations by the second quarter of 2012. However, due to the inherent uncertainties associated with construction, it is possible that commercial operations may resume after this timeframe which could impact our results for 2012.

Regulatory tariff revisions have a potential to adversely impact the results of our utility businesses. For example, Eletropaulo, our utility business in Brazil, is currently billing its customers under the pre-existing tariff as required by the regulator. In July 2011, the regulator postponed the review and reset of Eletropaulo's regulated tariff, which includes a tariff component that determines the margin Eletropaulo is allowed to earn. The review and reset of the regulated tariff is performed every four years. Management believes that it is probable that the new tariff rate will be lower than the current tariff rate, resulting in future refunds to customers, and based on its best estimate continues to record the amount of estimated future refunds as a reduction of revenue and a regulatory liability. The estimate is sensitive to the key assumption regarding the regulatory asset base that will be used by the regulator to determine the return included in the revised tariff. This assumption is subject to ongoing discussions with the regulator. As the periodic review and reset process progresses with the regulator into 2012, it is at least reasonably possible that the estimated amount of refunds will change in amounts that could require more refunds than we currently expect, in amounts that could be material.

See Item 1—Business—Regulatory Matters—*United States—The Dayton Power and Light Company* included in this Form 10-K for further information regarding DPL's expected filing with PUCO to propose either a new ESP or MRO to be effective January 1, 2013. The outcome of the proceeding could have a material impact on our results.

Global Economic Considerations

During the past few years, economic conditions in some countries where our subsidiaries conduct business have deteriorated. Global economic conditions remain volatile and could have an adverse impact on our businesses in the event these recent trends 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. At this time, the Euro Zone continues to face a sovereign debt crisis, the impacts of which are described below. 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.

In addition, in recent months, global economic sentiment has indicated that there is a possibility of global economic slowdown in the coming months. 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 declines 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 year ended December 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.

Euro Zone Debt Crisis. During the past year, certain European Union countries have continually faced a sovereign debt crisis and it is possible that this crisis could spread to other countries. 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. At December 31, 2011, the Company had unfunded commitments from European banks for our corporate revolver and for certain project finance debt totaling $142 million and $728 million, respectively. Approximately 7% of the non-recourse debt held by subsidiaries was denominated in Euros and 15% of our variable rate debt was indexed to Euribor at December 31, 2011. 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 this Form 10-K, our renewables businesses are dependent on favorable regulatory incentives, including subsidies, which are provided by sovereign governments, including European 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 sustain and/or grow their operations. For example, in 2011, tariffs for certain of our European solar businesses were reduced, and could be reduced further. The Company's investment in AES Solar Energy Ltd., whose primary operations are in Europe, was $225 million at December 31, 2011. During the year ended December 31, 2011, in connection with the tariff decreases, AES Solar Energy Ltd. recognized an impairment charge of $20 million on its assets, of which AES's share was $10 million. 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 example, our investments in Bulgaria rely on offtaker contracts from NEK, a fully state-owned entity. The Company has assets of $1.2 billion in Bulgaria. 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 this 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.

As noted in Item 1A—Risk Factors—"*We may not be adequately hedged against our exposure to changes in commodity prices or interest rates*", Item 7—Management's Discussion and Analysis, *Key Drivers of Results in 2011*, and Item 7A.—Quantitative and Qualitative Disclosures About Market Risk—*Commodity Price Risk* of this Form 10-K, the Company's North American businesses continue to face pressure as a result of high coal prices relative to natural gas, which has affected the results of certain of our coal plants in the region, particularly those which are merchant plants that are exposed to market risk and those that have hybrid merchant risk, meaning those businesses that have a PPA in place, but purchase fuel at market prices or under short term contracts. In 2011, AES Thames, LLC ("Thames"), our 208 MW coal-fired plant in Connecticut, and Eastern Energy, our coal-fired plants in New York; filed for bankruptcy and are no longer in our portfolio of businesses. In connection with the recent Eastern Energy bankruptcy filing, it is possible that creditors may attempt to bring claims against Eastern Energy and or directly against the AES Corporation. While we believe Eastern Energy and The AES Corporation would have meritorious defenses against any such claims, there can be no assurance that Eastern Energy or the AES Corporation would prevail in such claims. At this time, AES Deepwater has been idled to mitigate operating risks caused by high fuel costs and other competitive pressures. If the conditions described above continue or worsen, our North American businesses with market or hybrid merchant exposure may need to restructure their obligations or seek additional funding (including from the Parent) or face the possibility that they may be unable to meet their obligations and continue operations, which could result in the loss of earnings or cash flow or result in a write down in the value of these assets, any of which could have a material impact on the Company. For further discussion of the risks associated with commodity prices, see Item 1A.—Risk Factors "*We may not be adequately hedged against our exposure to changes in commodity prices or interest rates.*" of this Form 10-K.

If global economic conditions worsen, it could also affect the prices we receive for the electricity we generate or transmit. Utility regulators or parties to our generation contracts may seek to lower our prices 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 price 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 significant asset impairment. The Company continues to evaluate the impact of economic conditions on the fair value of our long-lived assets on an ongoing basis. 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;
- a significant adverse change in the extent or manner in which a long-lived asset group is being used or in its physical condition; and
- a current expectation that, more likely than not, a long-lived asset (asset group) will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

During the third quarter of 2011, the Company evaluated the future use of certain wind turbines held in storage pending their installation and turbine deposits. Due to reduced wind turbine market pricing and advances in turbine technology, the Company determined that it was more likely than not the turbines would be sold before the end of their previously estimated useful lives. At the same time, the Company also concluded that it was more likely than not non-refundable deposits that it had made in prior years to a turbine manufacturer for the purchase of wind turbines were not recoverable. The Company determined it was more likely than not that it would not proceed with the purchase of these turbines due to the availability of more advanced and lower cost turbines in the market. In October 2011, the Company determined that an impairment had occurred as of September 30, 2011 and wrote down the aggregate carrying amount of $161 million of these assets to their estimated fair value of $45 million by recognizing asset impairment expense of $116 million. In January 2012, the Company forfeited the deposits for which a full impairment charge was recognized in the third quarter of 2011, and there is no obligation for further payments under the related turbine supply agreement. Additionally, the Company sold some of the turbines held in storage during the fourth quarter of 2011 and is continuing to evaluate the future use of the turbines held in storage. The Company determined it is more likely than not that they will be sold, however they are not being actively marketed for sale at this time as the Company is reconsidering the potential use of the turbines in light of recent development activity at one of its advance stage development projects. It is reasonably possible that the turbines could incur further loss in value due to changing market conditions and advances in technology.

We have continued to evaluate the recoverability of our long-lived assets at Kelanitissa, our diesel-fired generation plant in Sri Lanka, as a result of both the existing government regulation which may require the government to acquire an ownership interest and the current expectation of future losses. In 2011, our evaluations indicated that the long-lived assets were not recoverable and accordingly, they were written down to their estimated fair value of $24 million based on a discounted cash flow analysis. Kelanitissa is a Build-operate-transfer (“BOT”) generation facility and payments under its PPA are scheduled to decline over the PPA term. It is possible that further impairment charges may be required in the future as Kelanitissa gets closer to the BOT date.

Equity method investments. Adverse changes in economic and business conditions could also impact the value of our equity method investments. For example, Yangcheng International Power Generating Co. Ltd ("Yangcheng"), our 2,100 MW coal-fired plant in China, which is accounted for under the equity method of accounting, continues to experience lower operating margin due to higher coal prices. The coal prices trended upward during the nine months ended September 30, 2011 and it is unlikely that the trend will reverse in the next several years. Due to the tight governmental control on the tariff, it is also difficult to pass through the increase in fuel costs to customers. At the end of the venture in 2016, AES is required to surrender its interest to other venture partners without additional compensation. During the third quarter of 2011, an other-than-temporary-impairment of $74 million was recognized to write down Yangcheng to its estimated fair value of $26 million. It is reasonably possible that further impairment expense may be required on Yangcheng or any other equity method investments if adverse changes occur in economic or business environments.

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 this Form 10-K, there is always a risk that "*Our acquisitions may not perform as expected*." One of the primary factors contributing to goodwill is the synergies expected from an acquisition that follow the integration of the acquired business with the existing operations of an entity. Thus, an entity's ability to realize benefits of goodwill depends on the successful integration of the acquired business. If such integration efforts are not successful, it could be difficult to realize the benefits of goodwill, which could result in impairment of goodwill. As described in Note 23—*Acquisitions and Dispositions* included in Item 8 of this Form 10-K, the Company completed the acquisition of DPL on November 28, 2011, which resulted in the provisional recognition of $ 2.5 billion of goodwill. Efforts to integrate DPL into the Company's existing operations are ongoing and the Company's ability to realize the benefit of DPL's goodwill will depend on our ability to realize the expected operating synergies and manage the market risks of DPL as further described in Item 1A.—Risk Factors of this Form 10-K "*After completion of the DPL 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."* Additionally, utilities in Ohio continue to face downward pressure on operating margins due to the evolving regulatory environment, which is moving towards a market-based competitive pricing mechanism. At the same time, the declining energy prices are also reducing operating margins across the utility industry. These competitive forces could adversely impact the future operating performance of DPL and may result in impairment of its goodwill.

The value of goodwill is also positively correlated with the economic environments in which our acquired businesses operate and a severe economic downturn could negatively impact the value 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 realized 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 2011, 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 at that time that could result in the recognition of goodwill impairment at our reporting units, it is possible we may incur goodwill impairment at our reporting units in future periods if any of the following events occur: a deterioration in general economic conditions (e.g., a recession), or the environment in which a business operates; an increased competitive environment (e.g., a new plant in the grid); a change in the market for a business' products or services; or a regulatory or political development (e.g., changing environmental regulations on coal consumption and water intake); increases in raw materials, labor, or other costs that have a negative effect on earnings (e.g., where a business cannot pass through the increase in input costs); negative or declining cash flows or a decline in actual or planned revenue or earnings (e.g., where recent results have been worse than previously expected); a more-likely-than-not expectation of selling or disposing all, or a portion of, a reporting unit; the testing for recoverability of a significant asset group within a reporting unit; or a business reaches the end of its finite life.

The likelihood of the occurrence of these events may increase if global economic conditions remain volatile or deteriorate further. For example, during the third quarter of 2011, the Company identified higher coal prices and the resulting reduced operating margins in China as an impairment indicator of goodwill at Chigen, our wholly-owned subsidiary that holds AES' interests in Chinese ventures. An interim evaluation of goodwill was performed at September 30, 2011 and its entire carrying amount of $17 million was recognized as a goodwill impairment.

See Note 20—*Impairment Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Recent Events

Cartagena—On February 9, 2012, a subsidiary of the Company completed the sale of 80% of its interest in the wholly-owned holding company of AES Energia Cartagena S.R.L. ("AES Cartagena"), a 1,199 MW gas-fired generation business in Spain. AES owned approximately 71% of AES Cartagena through this holding company structure. Net proceeds from the sale were approximately €172 million ($229 million). The Company expects to recognize a gain on the sale transaction in the range of $163 million to $179 million during the first quarter of 2012. Under the terms of the sale agreement, Electrabel International Holdings B.V., the buyer (a subsidiary of GDF SUEZ S.A. or "GDFS"), has an option to purchase AES' remaining 20% interest in the holding company for a fixed price of €28 million ($36 million) during a five month period beginning 13 months from February 9, 2012. Concurrent with the sale, GDFS settled the outstanding arbitration between the parties regarding certain emissions costs and other taxes that AES Cartagena sought to recover from GDFS as energy manager under the existing commercial arrangements. GDFS agreed to pay €71 million ($92 million) to AES Cartagena for such costs incurred by AES Cartagena for the 2008—2010 period and for 2011 through the date of sale close, of which €28 million ($38 million) was paid at closing. See Item 3—*Legal Proceedings* of this Form 10-K for further information. Due to the Company's expected continuing ownership interest extending beyond one year from the completion of the sale of its 80% interest, prior period operating results of AES Cartagena have not been reclassified as discontinued operations.

Red Oak—On February 10, 2012, a subsidiary of the Company signed a sale agreement with a newly-formed portfolio company of Energy Capital Partners II, LP for the sale of 100% of its membership interest in AES Red Oak, LLC and AES Sayreville, two wholly-owned subsidiaries, that hold the Company's interest in Red Oak, an 832 MW gas-fired generation business in New Jersey, for $147 million, subject to customary purchase price adjustments. Under the terms of the sale agreement, the buyer will assume the existing net indebtedness of Red Oak. The sale is expected to close by the end of the first quarter of 2012 and the Company does not expect to recognize a loss on the sale. Red Oak is reported in the North America Generation segment.

Ironwood—On February 23, 2012, a subsidiary of the Company signed a sale agreement with an indirect wholly-owned subsidiary of PPL Corporation for the sale of 100% of its equity interest in AES Ironwood, Inc., a wholly-owned subsidiary, that holds the Company's interest in Ironwood, a 710 MW gas-fired generation business in Pennsylvania, for $87 million, subject to customary purchase price adjustments. Under the terms of the sale agreement, the buyer will assume the existing net indebtedness of Ironwood. The sale is expected to close by the end of the first quarter of 2012 and the Company does not expect to recognize a loss on the sale. Ironwood is reported in the North America Generation segment.

Key Drivers of Results in 2011

In 2011, the Company's gross margin increased $198 million, net income attributable to The AES Corporation increased $49 million and cash flow from operations decreased $581 million compared to the prior year.

During the year ended December 31, 2011, the Company benefited from new businesses including a full year of operations from Ballylumford, in Northern Ireland, which was acquired in August 2010 and the impact of Angamos I, in Chile, and Maritza, in Bulgaria, which commenced commercial operations in April and June 2011, respectively. Gener, our generation business in Chile, saw improvements over the prior year due to higher generation at the Electrica Santiago plant running on liquefied natural gas and higher contract and spot sales. These favorable results were partially offset by an unfavorable adjustment to regulatory liabilities at Eletropaulo related to the estimated impact of the July 2011 tariff reset as discussed above.

In 2012, we expect to face continued challenges at certain of our businesses.

- The determination of the 2011 tariff reset in Brazil has not been finalized. Although we expect the tariff to decrease, the impact on the regulatory asset base and its potential impact on our Brazilian utility, Eletropaulo, remain uncertain at this time.
- Over the course of the second half of 2011, the marginal cost in the SING market in Chile has been impacted by the entrance of four new base load generation plants with approximately 800MW of capacity and local fuel price dynamics, negatively impacting our margin by reducing spot revenues. Furthermore, demand growth remained flat at a 3.5% growth rate similar to 2010. Marginal costs and demand projections are expected to remain at similar levels through most of 2012.
- The Company will continue to see the adverse effects of relatively lower gas prices and a decline in power prices relative to coal. See Item 7A.—Quantitative and Qualitative Disclosures About Market Risk of this Form 10-K for more information.
- The Company faces uncertainty over the U.S. taxation of earnings from its foreign subsidiaries following the expiration of a favorable tax provision in 2011 and expects its effective tax rate to increase, by amounts that could be material, if such provision is not renewed.

Additional items that could impact our 2012 results are discussed in *Key Trends and Uncertainties* above, along with the risk factors included in Item 1A.—Risk Factors of this Form 10-K. However, management expects that improved operating performance at certain businesses, growth from newly acquired businesses and global cost reduction initiatives may lessen or offset the impact of the challenges described above. 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, net income attributable to The AES Corporation and cash flows.

The following briefly describes the key changes in our reported revenue, gross margin, net income attributable to The AES Corporation, net cash provided by operating activities, diluted earnings per share from continuing operations and Adjusted Earnings per Share (a non-GAAP measure) for the year ended December 31, 2011 compared to 2010 and 2009 and should be read in conjunction with our *Consolidated Results of Operations* and *Segment Analysis* discussion within *Management's Discussion and Analysis of Financial Condition*.

Performance Highlights

	Year Ended December 31,		
	2011	**2010**	**2009**
	(in millions, except per share amounts)		
Revenue	$17,274	$15,828	$13,110
Gross margin	$ 4,134	$ 3,936	$ 3,357
Net income attributable to The AES Corporation	$ 58	$ 9	$ 658
Net cash provided by operating activities	$ 2,884	$ 3,465	$ 2,211
Diluted earnings per share from continuing operations	$ 0.59	$ 0.63	$ 1.08
Adjusted earnings per share (a non-GAAP measure)(1)	$ 1.04	$ 0.98	$ 1.06

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

Year Ended December 31, 2011

Revenue increased $1.4 billion, or 9%, to $17.3 billion in 2011 compared with $15.8 billion in 2010. Key drivers of the increase included:

- the favorable impact of foreign currency of $466 million;
- the impact of new businesses including Ballylumford, in Northern Ireland and DPL in the United States, acquired in August 2010 and late November 2011, respectively, and Angamos I, in Chile, and Maritza, in Bulgaria, that commenced commercial operations in April and June 2011, respectively;
- increased prices at our generation businesses in Argentina and at Gener, in Chile;
- increased volume at our Brazilian utilities, driven by increased market demand; and
- increased prices at our utility business in El Salvador due to higher fuel prices and drier weather.

These increases were partially offset by:

- lower prices at Eletropaulo, our utility business in Brazil, primarily related to the estimated impact of the July 2011 tariff reset which is expected to be finalized by the Brazilian energy regulatory agency in 2012; and
- lower volume at Cartagena, in Spain.

Gross margin increased $198 million, or 5%, to $4.1 billion in 2011 compared with $3.9 billion in 2010. Key drivers of the increase included:

- the favorable impact of foreign currency of $112 million;
- the impact of new businesses discussed above;
- increased volume at Gener;
- increased volume at our Brazilian utilities, driven by increased market demand; and
- increased volume and prices in the Dominican Republic.

These increases were partially offset by:

- lower prices at Eletropaulo, as discussed above;
- the unfavorable impact of an unrealized mark-to-market derivative loss at Sonel, in Cameroon;
- lower volume and rate in Hungary;
- lower rate and volume at Kilroot, in Northern Ireland; and

- an increase in global fixed costs, particularly at our Latin American generation businesses.

Net income attributable to The AES Corporation increased $49 million to $58 million in 2011, compared to $9 million in 2010. Key drivers of the increase included:

- an increase in gross margin as described above;
- a decrease in asset impairment expense due to higher prior year impairments related to the Southland generation facility offset primarily by current year impairments on wind turbines and deposits; and
- a decrease in losses from discontinued operations primarily related to a gain on sale of Brazil Telecom in 2011 partially offsetting a loss on disposal of our Argentina distribution businesses and losses at other discontinued businesses compared to a significant impairment recorded at New York in 2010.

This increase was partially offset by:

- an increase in interest expense due to increased debt and fees related to the DPL acquisition, reduced interest capitalization at Maritza due to commencement of operations in June 2011, and an unfavorable impact of foreign currency translation in Brazil; and
- a decrease in net equity in earnings of affiliates partially offset by income tax expense related to the sale of the Company's indirect investment in Companhia Energética de Minas Gerais ("CEMIG").

Net cash provided by operating activities decreased $581 million, or 17%, to $2.9 billion in 2011 compared with $3.5 billion in 2010. This net decrease was primarily due to the following:

- a decrease of $354 million at our Latin American utilities businesses primarily driven by our businesses in Brazil due to higher income tax payments of which $84 million is due to the sale of Brazil Telecom in October 2011, for which the pre-tax net sales proceeds of $890 million are recorded in cash flows from investing activities, and a one-time cash savings of $107 million mainly related to the utilization of a tax credit received as a result of the REFIS program in 2010, lower accounts receivable collections at Eletropaulo and higher payments for energy purchases, operation and maintenance expenses and pension contributions. These impacts were partially offset by higher accounts receivable collections at Sul;
- a decrease of $145 million at our North America generation businesses primarily due to reduced operations in New York prior to its deconsolidation in December 2011 and higher working capital requirements at Puerto Rico, partially offset by the deconsolidation of Thames; and
- a decrease of $56 million at Masinloc in the Philippines due to lower gross margin.

Although net income for the period increased $471 million for 2011, net cash provided by operating activities decreased $581 million during 2011. Included in net income for each period are items such as impairments and losses from discontinued operations, which have both decreased in 2011 and have contributed to the increase in net income for the period, but are largely excluded from net cash provided by operating activities because they either are non-cash in nature or the underlying cash activity is appropriately classified as an investing or financing activity. Also, net cash provided by operating activities in 2010 was impacted by certain non-recurring items, as discussed above, which were not expected to recur in 2011. The Company does not expect a further decrease in net cash provided by operating activities to continue in 2012, when compared to 2011, however, it can provide no assurance that such trend will not continue.

Year Ended December 31, 2010

Revenue increased $2.7 billion, or 21%, to $15.8 billion in 2010 compared with $13.1 billion in 2009. Key drivers of the increase included:

- the favorable impact of foreign currency of $802 million;

- increased volume and rates at our Brazilian utilities attributable to increased demand due to the recovery of the local economy and the favorable impact of the June 2009 tariff reset;
- the impact of the consolidation of Cartagena, in Spain, in accordance with the new consolidation accounting guidance which became effective January 1, 2010;
- the favorable impact of rates at our generation businesses in Argentina;
- higher generation rates and volume at Masinloc in the Philippines;
- higher demand at Gener in Chile;
- the impact of the Company's new business in Northern Ireland, acquired in August 2010;
- higher demand and rates at Indianapolis Power and Light; and
- higher volume in Ukraine.

Gross margin increased $579 million, or 17%, to $3.9 billion in 2010 compared with $3.4 billion in 2009. Key drivers of the increase included:

- the favorable impact of foreign currency of $212 million;
- an increase in demand at our generation and utilities businesses in Latin America;
- higher generation rates and volume at Masinloc in the Philippines; and
- the impact of the consolidation of Cartagena, in Spain, in accordance with the new consolidation accounting guidance which became effective January 1, 2010.

These increases were partially offset by an increase in fixed costs in Latin America, largely driven by bad debt recoveries and a reduction in bad debt expense in Brazil in 2009 that did not recur.

Net income attributable to The AES Corporation decreased $649 million to $9 million in 2010, compared to $658 million in 2009. Key drivers of the decrease included:

- impairment losses in New York related to our Eastern Energy facilities (whose results of operations are included in discontinued operations), in California related to our Southland (Huntington Beach) generation facility, in Hungary related to our Tisza II generation facility and in Texas related to our Deepwater facility;
- a decrease in gain on sale of investments due to the sale of our businesses in Northern Kazakhstan which occurred in 2009; and
- a decrease in other income due to the reduction in interest and penalties in 2009 associated with federal tax debts at Eletropaulo and Sul as a result of the Programa de Recuperacao Fiscal ("REFIS") program and a favorable court decision in 2009 enabling Eletropaulo to receive reimbursement of excess non-income taxes paid from 1989 to 1992 in the form of tax credits to be applied against future tax liabilities.

These decreases were partially offset by:

- the gain on sale of discontinued operations related to the sale of Barka which occurred in August 2010;
- an increase in net equity in earnings of affiliates partially offset by income tax expense related to the sale of the Company's indirect investment in CEMIG;
- goodwill impairment of our business in Kilroot that occurred in 2009;
- lower income tax expense due to 2010 asset impairments primarily recorded at certain U.S subsidiaries as referenced above; and

- an increase in gross margin as described above.

Net cash provided by operating activities increased $1.3 billion, or 57%, to $3.5 billion in 2010 compared with $2.2 billion in 2009. This net increase was primarily due to the following:

- an increase of $837 million at our Latin American utilities due to a one-time increase in tax payments in 2009 associated with a tax amnesty program of $326 million, higher working capital requirements during 2009 related to payments on the settlement of swap agreements of $65 million and in 2010, net cash provided by operating activities benefited from the one-time cash savings related to the utilization of tax credits received as a result of the REFIS program, as well as a $50 million decrease in employer contributions to pension plans and lower payments for contingencies;
- an increase of $215 million at our Latin American generation businesses due to the higher gross margin in 2010 combined with improved working capital mainly as a result of higher collections of value added taxes and accounts receivable;
- an increase of $99 million at Masinloc in the Philippines due to higher gross margin; and
- an increase of $22 million as a result of the acquisition of Ballylumford in Northern Ireland.

These increases were partially offset by a decrease of $191 million in operating cash flows from discontinued operations compared to 2009. In 2010, net cash provided by operating activities of discontinued and held for sale businesses was $82 million, including $33 million from businesses sold in 2010.

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.

	Year Ended December 31,		
Reconciliation of Adjusted Earnings Per Share	**2011**	**2010**	**2009**
Diluted earnings per share from continuing operations	$0.59	$ 0.63	$ 1.08
Derivative mark-to-market (gains) losses[1]	0.01	—	0.01
Currency transaction (gains) losses[2]	0.04	(0.05)	(0.05)
Disposition/acquisition (gains) losses	—	—[3]	(0.19)[4]
Impairment losses	0.36[5]	0.37[6]	0.21[7]
Debt retirement (gains) losses	0.04[8]	0.03[9]	—
Adjusted earnings per share	$1.04	$ 0.98	$ 1.06

(1) Derivative mark-to-market (gains) losses were net of income tax per share of $0.01, $0.00 and $0.00 in 2011, 2010 and 2009, respectively.

(2) Unrealized foreign currency transaction (gains) losses were net of income tax per share of $0.00, ($0.01) and $0.01 in 2011, 2010 and 2009, respectively.

(3) The Company did not adjust for the gain or the related tax effect from the sale of its indirect investment in CEMIG, disclosed in Note 7—*Investments in and Advances to Affiliates* included in Item 8 of this form 10-K, in its determination of Adjusted EPS because the gain was recognized by an equity method investee. The Company does not adjust for transactions of its equity method investees in its determination of adjusted EPS.

(4) Amount includes: Kazakhstan gain of $98 million, or $0.15 per share, related to the termination of a management agreement as well as a gain of $13 million, or $0.02 per share, related to the reversal of a withholding tax contingency. In addition, there was a gain on sale associated with the shutdown of the Hefei plant in China of $14 million, or $0.02 per share. There were no taxes associated with any of these transactions.

(5) Amount includes asset impairments, equity method investment impairments and a goodwill impairment. Asset impairments primarily includes impairments of wind turbines and deposits of $116 million ($75 million, or $0.10 per share, net of income taxes), Tisza II of $52 million ($50 million, or $0.06 per share, net of income taxes), Kelanitissa of $42 million ($38 million, or $0.05 per share, net of non-controlling interest), and Bohemia of $9 million, or $0.01 per share. Equity method investment impairments primarily included the impairments at Chigen, including Yangcheng, of $79 million, or $0.10 per share. Goodwill impairment at Chigen of $17 million, or $0.02 per share.

(6) Amount primarily includes asset impairments at Southland (Huntington Beach) of $200 million, Tisza II of $85 million, and Deepwater of $79 million ($130 million, or $0.17 per share, $69 million, or $0.09 per share, and $51 million, or $0.07 per share, net of income tax, respectively) and goodwill impairment at Deepwater of $18 million (or $0.02 per share, with no income tax impact).

(7) Amount includes: goodwill impairments at Kilroot of $118 million, or $0.18 per share, and in the Ukraine of $4 million, or $0.01 per share; write-off of development project costs in Latin America and Asia of $19 million ($11 million net of noncontrolling interests, or $0.01 per share) and an impairment of $10 million, or $0.01 per share, of the Company's investment in a company developing "blue gas" (coal to gas) technology. There was no income tax impact associated with any of these transactions.

(8) Amount includes loss on retirement of debt at Gener of $38 million ($22 million, or $0.03 per share, net of income taxes and noncontrolling interests) and at IPL of $15 million ($10 million, or $0.01 per share, net of income taxes).

(9) Amount includes loss on retirement of debt at the Parent Company of $15 million, at Andres of $10 million, and at Itabo of $8 million ($10 million, or $0.01 per share, net of income tax at the Parent Company, $10 million, or $0.01 per share at Andres net of income tax, and $4 million, or $0.01 per share, net of noncontrolling interest at Itabo).

Consolidated Results of Operations

Results of operations	2011	2010	2009	$ change 2011 vs. 2010	$ change 2010 vs. 2009
	Year Ended December 31, (in millions, except per share amounts)				
Revenue:					
Latin America Generation	$ 4,982	$ 4,281	$ 3,651	$ 701	$ 630
Latin America Utilities	7,374	6,987	5,877	387	1,110
North America Generation	1,465	1,453	1,381	12	72
North America Utilities	1,326	1,145	1,068	181	77
Europe Generation	1,550	1,318	762	232	556
Asia Generation	625	618	375	7	243
Corporate and Other[1]	1,106	1,045	858	61	187
Eliminations[2]	(1,154)	(1,019)	(862)	(135)	(157)
Total Revenue	$17,274	$15,828	$13,110	$1,446	$2,718
Gross Margin:					
Latin America Generation	$ 1,840	$ 1,497	$ 1,357	$ 343	$ 140
Latin America Utilities	1,035	1,023	866	12	157
North America Generation	400	410	404	(10)	6
North America Utilities	220	249	239	(29)	10
Europe Generation	359	310	244	49	66
Asia Generation	178	240	93	(62)	147
Corporate and Other[3]	75	190	134	(115)	56
Eliminations[4]	27	17	20	10	(3)
General and administrative expenses	(391)	(392)	(339)	1	(53)
Interest expense	(1,603)	(1,503)	(1,461)	(100)	(42)
Interest income	400	408	344	(8)	64
Other expense	(156)	(234)	(104)	78	(130)
Other income	149	100	459	49	(359)
Gain on sale of investments	8	—	131	8	(131)
Goodwill impairment	(17)	(21)	(122)	4	101
Asset impairment expense	(225)	(389)	(20)	164	(369)
Foreign currency transaction gains (losses)	(38)	(33)	35	(5)	(68)
Other non-operating expense	(82)	(7)	(12)	(75)	5
Income tax expense	(636)	(579)	(557)	(57)	(22)
Net equity in earnings (losses) of affiliates	(2)	184	93	(186)	91
Income from continuing operations	1,541	1,470	1,804	71	(334)
Income (loss) from operations of discontinued businesses	(97)	(475)	101	378	(576)
Gain (loss) from disposal of discontinued businesses	86	64	(150)	22	214
Net income	1,530	1,059	1,755	471	(696)
Noncontrolling interests:					
Income from continuing operations attributable to noncontrolling interests	(1,083)	(986)	(1,080)	(97)	94
Income from discontinued operations attributable to noncontrolling interests	(389)	(64)	(17)	(325)	(47)
Net income attributable to The AES Corporation	$ 58	$ 9	$ 658	$ 49	$ (649)
Per Share Data:					
Basic earnings per share from continuing operations	$ 0.59	$ 0.63	$ 1.09	$ (0.04)	$ (0.46)
Diluted earnings per share from continuing operations	$ 0.59	$ 0.63	$ 1.08	$ (0.04)	$ (0.45)

(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 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—Generation

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

	For the Years Ended December 31,				
	2011	2010	2009	% Change 2011 vs. 2010	% Change 2010 vs. 2009
	($'s in millions)				
Latin America Generation					
Revenue	$4,982	$4,281	$3,651	16%	17%
Gross Margin	$1,840	$1,497	$1,357	23%	10%

Fiscal Year 2011 versus 2010

Excluding the favorable impact of foreign currency translation and remeasurement of $13 million, primarily in Brazil partially offset by Argentina, generation revenue for 2011 increased $688 million, or 16%, from 2010 primarily due to:

- higher energy prices of $210 million in Argentina attributable to a price adjustment for consuming an alternate fuel;
- new business of $175 million at Angamos in Chile;
- higher contract and spot prices of $150 million at Gener as a result of lower water inflows in the Central Interconnected System and PPA price indexation;
- higher volume of $113 million in Colombia and Panama due to higher water inflows in the system during 2011;
- higher contract prices and volume of $80 million at Tietê as a result of the combined effect of higher spot sales and PPA indexation to CPI in the second half of 2011; and
- higher ancillary services and third party gas sales of $57 million higher as well as contract prices of $53 million primarily from PPAs indexed to coal in the Dominican Republic.

These increases were partially offset by:

- lower spot prices of $128 million in Colombia due to higher water inflows in the system during 2011;
- a decrease of $32 million related to the final settlement of the power sales agreement between Uruguaiana and Sul in the second quarter of 2010; and
- a net decrease of $19 million related to the forced outage in Panama.

Excluding the favorable impact of foreign currency translation and remeasurement of $34 million, primarily in Brazil, generation gross margin for 2011 increased $309 million, or 21%, from 2010 primarily due to:

- higher volume of $158 million at Gener—Electrica Santiago due to improved fuel availability;
- higher volume of $110 million in Colombia as a result of higher water inflows in the system during 2011;
- higher contract prices and volume of $84 million at Tietê, as discussed above;
- new business of $51 million at Angamos;
- higher ancillary services and gas sales of $36 million and higher energy prices of $27 million in the Dominican Republic; and

- higher volume and price of $26 million at our coal generation businesses in Argentina as a result of low hydrology.

These increases were partially offset by:

- lower spot prices of $92 million in Colombia due to higher water inflows in the system during 2011;
- higher fixed and operating costs of $71 million across the region, primarily attributable to higher employee costs, maintenance costs, an increase in non-income taxes in Argentina and Colombia, and higher depreciation at Tietê due to the change in useful lives and salvage values of property, plant and equipment, as a result of new regulatory information received;
- a decrease of $39 million related to higher spot purchases and the forced outage in Panama; and
- a decrease of $32 million related to the final settlement of the power sales agreement between Uruguaiana and Sul as discussed above.

For the year ended December 31, 2011, revenue increased 16% while gross margin increased 23%, primarily due to the lower energy purchases at Gener due to higher generation.

Fiscal Year 2010 versus 2009

Excluding the favorable impact of foreign currency translation and remeasurement of $133 million, generation revenue for 2010 increased $497 million, or 14%, from 2009 primarily due to:

- higher spot prices of $221 million associated with increased fuel prices in Argentina;
- higher volume of $139 million at Gener in Chile due to higher demand;
- higher volume and ancillary services of $115 million, higher contract prices from PPAs indexed to gas and higher spot prices of $27 million in the Dominican Republic;
- higher contract prices of $58 million in Colombia and Tietê in Brazil;
- the positive impact of $28 million resulting from the final settlement of the power sales agreement between Sul and Uruguaiana, our businesses in Brazil; and
- higher volume of $21 million in Panama due to higher water inflows into the system.

These increases were partially offset by:

- lower volume sold at Uruguaiana of $53 million as a result of renegotiation of its power sales agreements;
- lower volume due to unfavorable hydrology in Colombia and Argentina of $41 million;
- lower contract prices at Gener of $32 million; and
- lower contract prices on PPAs indexed to international coal prices in the Dominican Republic of $22 million.

Excluding the favorable impact of foreign currency translation and remeasurement of $106 million, generation gross margin for 2010 increased $34 million, or 3%, from 2009 primarily due to:

- higher spot prices in Argentina of $69 million;
- higher volume and ancillary services in the Dominican Republic of $55 million;
- higher contract prices of $33 million in Colombia;
- the positive impact of $28 million resulting from the final settlement of the power sales agreement between Sul and Uruguaiana, as mentioned above; and

- higher volume of $23 million in Panama.

These increases were partially offset by:

- higher fuel and purchased energy prices at Gener of $48 million;
- the net effect of lower PPA prices and higher fuel costs in the Dominican Republic of $38 million;
- the impact of a reversal of bad debt expense during the first quarter of 2009 of $36 million at Uruguaiana as a result of the renegotiation of one of its power sales agreements; and
- higher fixed costs of $30 million at Gener primarily due to higher employee costs, increased maintenance expenses and costs incurred due to construction delays at Campiche.

For the year ended December 31, 2010, revenue increased by 17% while gross margin increased 10%, primarily due to higher spot purchases and fuel prices at Gener and the reversal of bad debt expense as a result of the renegotiation of one of the power sales agreements at Uruguaiana in the first quarter of 2009.

Latin America—Utilities

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

	For the Years Ended December 31,				
	2011	2010	2009	% Change 2011 vs. 2010	% Change 2010 vs. 2009
	($'s in millions)				
Latin America Utilities					
Revenue	$7,374	$6,987	$5,877	6%	19%
Gross Margin	$1,035	$1,023	$ 866	1%	18%

Fiscal Year 2011 versus 2010

Excluding the favorable impact of foreign currency translation of $362 million in Brazil, utilities revenue for 2011 increased $25 million, or flat to 2010 primarily due to:

- higher volume of $277 million due to increased market demand in Brazil;
- higher tariffs of $95 million in El Salvador due to increased energy prices related to higher fuel prices and drier weather which are pass-through to customers; and
- higher tariffs of $27 million at Sul in Brazil due to higher volume of energy purchases which are pass-through to customers.

These increases were partially offset by:

- lower tariffs of $207 million at Eletropaulo in Brazil, related to the estimated impact of the July 2011 tariff reset which is expected to be finalized by the Brazilian energy regulatory agency in 2012; and
- lower tariffs of $139 million at Eletropaulo due to lower energy prices associated with energy purchases and pass-through transmission costs.

Excluding the favorable impact of foreign currency translation of $63 million in Brazil, utilities gross margin for 2011 decreased $51 million, or 5%, from 2010 primarily due to:

- lower tariffs of $190 million at Eletropaulo, primarily related to the estimated impact of the July 2011 tariff reset as discussed above; and

- higher depreciation of $50 million primarily in Brazil mainly due to the change in estimates of the useful lives and salvage values of property, plant and equipment, as a result of new regulatory information.

These decreases were partially offset by:

- higher volume of $117 million in Brazil due to increased market demand; and
- lower fixed costs of $67 million primarily due to contingency reversals and a non-recurring reduction in bad debt expense in Brazil.

For the year ended December 31, 2011, revenue increased 6% while gross margin increased 1%, primarily due to higher pass-through costs to customers and higher depreciation.

Fiscal Year 2010 versus 2009

Excluding the favorable impact of foreign currency translation of $690 million, primarily in Brazil, utilities revenue for 2010 increased $420 million, or 7%, from 2009 primarily due to:

- increased volume of $300 million, primarily in Brazil, due to increased market demand; and
- higher tariffs of $111 million primarily related to the July 2009 tariff reset in Brazil partially offset by the unfavorable impact on rates at Eletropaulo in Brazil of a cumulative adjustment to regulatory liabilities and higher energy prices across our Latin America utility businesses associated with energy purchases passed through to customers of $97 million.

Excluding the favorable impact of foreign currency translation of $100 million, primarily in Brazil, utilities gross margin for 2010 increased $57 million, or 7%, from 2009 primarily due to:

- increased volume of $147 million, primarily in Brazil, due to the increased market demand; and
- lower contingencies of $142 million in Eletropaulo primarily related to labor contingencies which included a one-time reversal, reflecting an agreement with Fundação CESP, the pension plan administrator, of $51 million associated with claims for past benefit obligations which will now be accounted for as a component of the pension plan.

These increases were partially offset by:

- higher fixed costs of $224 million primarily due to the recovery in 2009 of a municipality receivable previously written off in Brazil and higher salaries and other employee related costs, provisions for commercial losses, regulatory penalties and maintenance costs; and
- $28 million related to the final settlement of the power sales agreement between Sul and Uruguaiana.

North America—Generation

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

	For the Years Ended December 31,				
	2011	2010	2009	% Change 2011 vs. 2010	% Change 2010 vs. 2009
			($'s in millions)		
North America Generation					
Revenue	$1,465	$1,453	$1,381	1%	5%
Gross Margin	$ 400	$ 410	$ 404	-2%	1%

Fiscal Year 2011 versus 2010

Excluding the favorable impact of foreign currency translation of $9 million, generation revenue for 2011 increased $3 million, or flat compared to 2010 primarily due to:

- an increase in Puerto Rico of $23 million primarily due to a prior year forced outage and the related penalty and $20 million due to higher rates; and
- higher volume of $8 million at TEG/TEP in Mexico.

These increases were offset by:

- a decrease in volume of $21 million at Deepwater in Texas due to the layup of the plant in January 2011 caused by high fuel costs and diminishing power prices; and
- decreases at Merida in Mexico of $18 million due to lower rates and volume and $7 million due to a combination of forced and scheduled outages.

Generation gross margin for 2011 decreased $10 million, or 2%, from 2010 primarily due to:

- a decrease of $12 million at TEG/TEP due to a combination of forced and scheduled outages and higher fuel costs;
- higher fuel costs and lower volume at Hawaii of $11 million;
- higher fuel costs at Shady Point in Oklahoma of $10 million;
- a decrease in volume of $6 million at Deepwater as discussed above; and
- a decrease of $5 million at Merida due to a combination of forced and scheduled outages.

These decreases were partially offset by:

- an increase of $15 million in Hawaii due to a favorable impact of prior year mark-to-market derivative adjustments;
- lower fixed costs at Deepwater of $10 million as discussed above; and
- an increase in Puerto Rico of $9 million primarily due to a prior year forced outage and the related penalty.

Fiscal Year 2010 versus 2009

Excluding the favorable impact of foreign currency translation of $19 million, generation revenue for 2010 increased $53 million, or 4%, from 2009 primarily due to:

- increased rates, volume and an availability bonus at TEG/TEP in Mexico of $41 million;
- higher volume, primarily due to fewer outages and higher rates, of $22 million at Merida in Mexico; and
- higher volume of $19 million at Warrior Run in Maryland due to fewer outages.

These increases were partially offset by:

- a net decrease of $18 million at Deepwater in Texas primarily due to lower volume; and
- a net decrease of $14 million in Puerto Rico primarily due to a penalty from a forced outage.

Excluding the favorable impact of foreign currency translation of $3 million, generation gross margin for 2010 increased $3 million, or 1%, from 2009 primarily due to:

- a net increase of $26 million at TEG/TEP due to a current year availability bonus and fewer outages partially offset by higher fuel prices; and

- higher volume of $14 million at Warrior Run due to fewer outages.

These increases were partially offset by:

- a decrease of $16 million at Deepwater due to lower volume and rates;
- a net decrease of $11 million in Puerto Rico primarily due to a forced outage; and
- a decrease of $9 million in Hawaii due to an unfavorable impact of mark-to-market derivatives.

North America—Utilities

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

	For the Years Ended December 31,				
	2011	2010	2009	% Change 2011 vs. 2010	% Change 2010 vs. 2009
			($'s in millions)		
North America Utilities					
Revenue	$1,326	$1,145	$1,068	16%	7%
Gross Margin	$ 220	$ 249	$ 239	-12%	4%

Fiscal Year 2011 versus 2010

Utilities revenue for 2011 increased $181 million, or 16%, from 2010 primarily due to:

- an increase of $154 million from the operations of DPL, in Ohio, which was acquired on November 28, 2011; and
- higher prices of $67 million, primarily due to higher fuel adjustment charges of $57 million at IPL in Indiana.

These increases were partially offset by the following at IPL:

- lower retail volume of $21 million, primarily due to unfavorable weather and economic conditions; and
- lower wholesale volume of $16 million, primarily due to increased generating unit outages.

Utilities gross margin for 2011 decreased $29 million, or 12%, from 2010 primarily due to the following at IPL:

- lower wholesale margin of $12 million, primarily due to increased generating unit outages;
- lower retail margin of $11 million, primarily due to unfavorable volume as discussed above; and
- higher salaries, wages and benefits of $7 million, primarily due to increased overtime and higher pay rates in 2011.

These decreases were partially offset by:

- increase of $6 million from the operations of DPL, which was acquired on November 28, 2011.

For the year ended December 31, 2011, revenue increased by 16% while gross margin decreased 12%, primarily due to the positive impact of higher-pass through on revenue at IPL, which had no corresponding impact on gross margin and the unfavorable impact on gross margin from one-time acquisition charges of $16 million related to DPL.

Fiscal Year 2010 versus 2009

Utilities revenue for 2010 increased $77 million, or 7%, from 2009 primarily due to:

- higher retail demand of $64 million as a result of warmer weather and higher fuel adjustment charges; and
- increased wholesale revenue of $11 million primarily due to higher prices.

Utilities gross margin for 2010 increased $10 million, or 4%, from 2009 primarily due to:

- higher retail margin of $20 million due to increased demand;
- lower pension expense of $12 million; and
- lower emission allowance expense of $5 million.

These increases were partially offset by:

- increased maintenance expenses of $16 million due to the timing of major generating unit overhauls; and
- increased fixed costs of $14 million.

For the year ended December 31, 2010, revenue increased by 7% while gross margin increased 4%, primarily due to increased fuel and maintenance costs.

Europe—Generation

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

	For the Years Ended December 31,				
	2011	2010	2009	% Change 2011 vs. 2010	% Change 2010 vs. 2009
			($'s in millions)		
Europe Generation					
Revenue	$1,550	$1,318	$762	18%	73%
Gross Margin	$ 359	$ 310	$244	16%	27%

Fiscal Year 2011 versus 2010

Excluding the favorable impact of foreign currency translation of $47 million, generation revenue for 2011 increased $185 million, or 14%, from 2010 primarily due to:

- $256 million from the operations at Ballylumford which was acquired in August 2010, driven by $224 million resulting from the acquisition and $32 million primarily from better availability due to a planned outage in 2010; and
- new business of $182 million at Maritza, which commenced commercial operations in June 2011.

These increases were partially offset by:

- lower revenue of $160 million at Cartagena primarily due to lower pass-through energy costs;
- lower revenue of $54 million in Hungary primarily from lower contract sales, lower spot market sales and lower volume on ancillary services, partially offset by higher capacity prices; and

- lower revenue of $46 million at Kilroot, in Northern Ireland, primarily resulting from the cancellation of the long-term PPA and supplementary agreements in November 2010.

Excluding the favorable impact of foreign currency translation of $12 million, generation gross margin for 2011 increased $37 million, or 12%, from 2010 primarily due to:

- $77 million from the operations at Ballylumford, acquired in August 2010, driven by $64 million resulting from the acquisition and $13 million primarily from better availability due to a planned outage in 2010; and
- $66 million at Maritza, which commenced operations in June 2011.

These increases were partially offset by:

- lower gross margin of $68 million at Kilroot, primarily resulting from cancellation of the long-term PPA and supplementary agreements in November 2010, lower capacity factor due to a decline in market demand, partially offset by CO2 costs passed through in the market price; and
- lower gross margin of $55 million in Hungary primarily due to decreased market demand, lower ramp-up ancillary services and lower spark spread, partially offset by higher capacity prices.

In February 2012, the Company completed the sale of 80% of our interest in Cartagena. Due to the Company's continuing involvement in the business subsequent to the sale, Cartagena is presented as held for sale on the Consolidated Balance Sheets, but presented in continuing operations on the Consolidated Income Statements. Accordingly, 2012 revenue and gross margin will be negatively impacted by the sale.

Fiscal Year 2010 versus 2009

Excluding the unfavorable impact of foreign currency translation of $37 million, generation revenue for 2010 increased $593 million, or 78%, from 2009 primarily due to:

- $409 million from the adoption of new accounting guidance on the consolidation of variable interest entities ("VIEs") which resulted in the consolidation of Cartagena in Spain, a generation business previously accounted for under the equity method of accounting;
- $117 million from the operations of Ballylumford in the United Kingdom, which was acquired in August 2010;
- higher tariffs of $16 million at Altai in Kazakhstan;
- $15 million from a full year of combined cycle operations at our Amman East plant in Jordan, which was single cycle until August 2009; and
- higher volume of $15 million at Kilroot in the United Kingdom largely driven by coal pass-through and increased demand, partially offset by lower capacity revenue due to the termination of the long term PPA and related supplementary agreements.

Generation gross margin for 2010 increased $66 million, or 27%, from 2009 primarily due to:

- $62 million from the consolidation of Cartagena as discussed above;
- higher tariffs and lower fixed costs at Altai of $29 million; and
- $13 million from the operations of Ballylumford since its acquisition.

These increases were partially offset by:

- lower gross margin of $28 million primarily from the termination of the long-term PPA at Kilroot; and

- lower gross margin of $11 million in Hungary primarily attributable to higher fuel costs that could not be passed through and lower sales of emission allowances.

For the year ended December 31, 2010, revenue increased 73% while gross margin increased 27%, primarily due to the consolidation of Cartagena and acquisition of Ballylumford that had a larger positive impact on revenue than gross margin, and the positive impact of higher energy revenue at Kilroot, which as a pass-through had no corresponding impact on gross margin.

Asia—Generation

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

	For the Years Ended December 31,				
	2011	2010	2009	% Change 2011 vs. 2010	% Change 2010 vs. 2009
	($'s in millions)				
Asia Generation					
Revenue	$625	$618	$375	1%	65%
Gross Margin	$178	$240	$ 93	-26%	158%

Fiscal Year 2011 versus 2010

Excluding the favorable impact of foreign currency translation of $20 million, generation revenue for 2011 decreased $13 million, or 2%, from 2010 primarily due to:

- a decrease of $39 million at Masinloc in the Philippines primarily due to lower generation prices and volume. Spot volume and prices were lower due to flat electricity demand and higher available capacity in the grid;
- a decrease of $12 million due to the closure of Aixi in China in November 2010; and
- outages of $9 million at Kelanitissa in Sri Lanka resulting in lower plant availability in 2011.

These decreases were partially offset by:

- higher generation rates of $18 million due to higher pass-through fuel costs and higher generation volume of $29 million at Kelanitissa due to higher offtaker demand as a result of lower hydrology.

Excluding the favorable impact of foreign currency translation of $8 million, generation gross margin for 2011 decreased $70 million, or 29%, from 2010 primarily due to:

- decrease of $59 million at Masinloc primarily attributable to a combination of flat market demand, lower spot prices, higher coal prices and increased fixed costs.

For the year ended December 31, 2011, revenue increased 1% while gross margin decreased 26%, primarily due to higher pass-through fuel costs at Kelanitissa which had a positive impact on revenue but no corresponding impact on gross margin and the negative influence on gross margin arising from lower spot prices at Masinloc, as well as increases in coal prices and fixed costs.

Fiscal Year 2010 versus 2009

Excluding the favorable impact of foreign currency translation of $28 million, generation revenue for 2010 increased $215 million, or 57%, from 2009 primarily due to:

- favorable generation rates and volume of $210 million at Masinloc in the Philippines as a result of increased market demand and improved plant availability subsequent to the completion of its overhaul at the beginning of 2010; and

- higher demand from both new and existing contract and spot customers as a result of lower supply shortages in the Philippines power market due to a strong energy growth rate.

Excluding the favorable impact of foreign currency translation of $13 million, generation gross margin for 2010 increased $134 million, or 144%, from 2009 primarily due to:

- a combination of higher availability attributable to improved plant operations, higher market demand and favorable spot prices at Masinloc.

For the year ended December 31, 2010, revenue increased 65% while gross margin increased 158%, primarily due to the positive influence on gross margin due to favorable spot rates and operational efficiencies resulting from the Masinloc plant overhauls in late 2009 and early 2010, which led to higher availability and allowed for more efficient operations that have materially improved the operating results for 2010 as compared to 2009.

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 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 Years Ended December 31,				
	2011	2010	2009	% Change 2011 vs. 2010	% Change 2010 vs. 2009
			($'s in millions)		
Revenue					
Europe Utilities	$ 418	$ 356	$286	17%	24%
Africa Utilities	386	422	370	-9%	14%
Africa Generation	91	87	70	5%	24%
Wind Generation	235	202	133	16%	52%
Corp/Other	9	4	4	125%	0%
Eliminations	(33)	(26)	(5)	-27%	-420%
Total Corporate and Other	$1,106	$1,045	$858	6%	22%
Gross Margin					
Europe Utilities	$ 23	$ 21	$ 16	10%	31%
Africa Utilities	(59)	64	70	-192%	-9%
Africa Generation	45	52	39	-13%	33%
Wind Generation	72	43	9	67%	378%
Corp/Other	(8)	6	(5)	-233%	220%
Eliminations	2	4	5	-50%	-20%
Total Corporate and Other	$ 75	$ 190	$134	-61%	42%

Fiscal Year 2011 versus 2010

Excluding the favorable impact of foreign currency translation of $16 million, Corporate and Other revenue increased $45 million for 2011, or 4% from 2010. The increase was primarily due to:

- higher tariff of $71 million at our utility businesses in the Ukraine; and
- $12 million from St. Nikola in Bulgaria that commenced commercial operations in March 2010.

These increases were partially offset by:

- a net decrease of $52 million at Sonel in Cameroon primarily due to the unfavorable impact of an unrealized mark-to-market derivative adjustment, partially offset by higher tariff and volume.

Excluding the unfavorable impact of foreign currency translation of $4 million, Corporate and Other gross margin decreased $111 million for 2011, or 58% from 2010. The decrease was primarily due to:

- a decrease of $119 million at Sonel primarily due to the unfavorable impact of an unrealized mark-to-market derivative adjustment and higher fixed costs.
- a decrease of $16 million in the Ukraine primarily due to higher fixed costs.

These decreases were partially offset by:

- gross margin of $10 million at St. Nikola, as discussed above.

For the year ended December 31, 2011, revenue increased 6% while gross margin decreased 61%, primarily due to higher pass-through costs in the Ukraine which had a positive impact on revenue but no corresponding impact on gross margin and higher fixed costs at Sonel.

Fiscal Year 2010 versus 2009

Excluding the unfavorable impact of foreign currency translation of $30 million, primarily in Cameroon, Corporate and Other revenue increased $217 million for 2009, or 25%, from 2009. The increase was primarily due to:

- higher volume at our utility businesses in Ukraine driven by an overall increase in market demand;
- higher volume and utility tariffs at Sonel in Cameroon driven by an increase in market demand; and
- incremental revenue from new wind generation projects that commenced operations during the year and an overall volume increase across our wind businesses.

Excluding the unfavorable impact of foreign currency translation of $9 million, primarily in Cameroon, Corporate and Other gross margin increased $65 million for 2009, or 49%, from 2009. The increase was primarily due to:

- an increase in gross margin from our new wind generation projects and higher volume, as discussed above; and
- an increase in volume at Dibamba, our generation business, in Cameroon.

These increases were partially offset by:

- an increase in fixed costs at Sonel.

General and Administrative Expense

General and administrative expense includes those expenses related to corporate and region staff functions and/or initiatives, executive management, finance, legal, human resources, information systems, and development costs.

General and administrative expenses decreased $1 million to $391 million in 2011 from 2010. The decrease is primarily related to reduction of business development costs and SAP implementation costs offset by DPL transaction costs.

General and administrative expenses increased $53 million, or 16%, to $392 million in 2010 from 2009. The increase is primarily related to business development costs associated with increased development efforts, primarily in Europe, Turkey and India.

Interest expense

Interest expense increased $100 million, or 7%, to $1.6 billion in 2011 from 2010. This increase was primarily due to less interest capitalization at Maritza due to commencement of operations in June 2011, a monetary correction related to value-added tax on commercial losses at Eletropaulo, the unfavorable impact of foreign currency translation in Brazil, higher interest rates at Eletropaulo, and increased debt and fees related to the DPL acquisition. These increases were partially offset by lower interest rates at Tietê, and a fee on a non-exercised credit line was written off in Brazil in 2010.

Interest expense increased $42 million, or 3%, to $1.5 billion in 2010 from 2009. This increase was primarily due to interest expense at Cartagena which is now a consolidated entity, higher interest rates at Tietê, increased debt principal at Eletropaulo and interest being expensed related to St. Nikola, our wind project in Bulgaria, due to commencement of operations in 2010. These increases were partially offset by reduced debt at the Parent Company.

Interest income

Interest income decreased $8 million, or 2%, to $400 million in 2011 from 2010. The decrease was primarily due to the settlement of a dispute related to inflation adjustments for energy sales at Tietê in 2010. The decrease was partially offset by favorable foreign currency translation in Brazil.

Interest income increased $64 million, or 19%, to $408 million in 2010 from 2009. This increase was primarily due to a higher average balance in short term investments at Eletropaulo and the favorable impact of foreign currency translation in Brazil as well as the settlement of a dispute related to inflation adjustments for energy sales at Tietê. These increases were partially offset by reduced interest income from a loan to a wind development project in Brazil which was repaid in June 2010.

Other income

See discussion of the components of other income in Note 19—*Other Income & Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K.

Other expense

See discussion of the components of other expense in Note 19—*Other Income & Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K.

Goodwill Impairment

The Company recognized goodwill impairment of $17 million, $21 million and $122 million for the years ended December 31, 2011, 2010 and 2009, respectively.

See Note 9—*Goodwill and Other Intangible Assets* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further discussion on goodwill impairment.

Asset Impairment Expense

The Company recognized asset impairment expense of $225 million, $389 million and $20 million for the years ended December 31, 2011, 2010 and 2009, respectively.

See Note 20—*Impairment Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Gain on sale of investments

Gain on sale of investments of $8 million in 2011 consisted primarily of the gain related to the sale of Wuhu, an equity method investment in China.

There was no gain on sale of investments in 2010.

Gain on sale of investments of $131 million in 2009 consisted primarily of $98 million recognized in May 2009 related to the termination of the management agreement between the Company and Kazakhmys PLC for Ekibastuz and Maikuben, a gain of $14 million from the sale of the remaining assets associated with the shutdown of the Hefei plant in China and $13 million from the reversal of a contingent liability related to the Kazakhstan sale in 2008.

Foreign currency transaction gains (losses) on net monetary position

The following table summarizes the gains (losses) on the Company's net monetary position from foreign currency transaction activities:

	Years Ended December 31,		
	2011	2010	2009
		(in millions)	
AES Corporation	$ (10)	$(50)	$ 13
Chile	(19)	8	65
Philippines	3	8	15
Brazil	(12)	(6)	(9)
Argentina	16	12	(10)
Kazakhstan	—	1	(24)
Colombia	1	(4)	(11)
Other	(17)	(2)	(4)
Total[1]	$ (38)	$(33)	$ 35

(1) Includes gains (losses) of $44 million, $(10) million and $(39) million on foreign currency derivative contracts for the years ended December 31, 2011, 2010 and 2009, respectively.

The Company recognized foreign currency transaction losses of $38 million for the year ended December 31, 2011. These losses consisted primarily of losses in Chile, Brazil, and at The AES Corporation, partially offset by gains in Argentina.

- Losses of $19 million in Chile were primarily due to an 11% devaluation of the Chilean Peso, resulting in losses at Gener (a U.S. Dollar functional currency subsidiary) associated with net working capital denominated in Chilean Pesos, mainly cash, accounts receivable, tax receivables and a $5 million loss on foreign currency derivatives.
- Losses of $12 million in Brazil were primarily due to a 13% devaluation of the Brazilian Real resulting in losses mainly associated with U.S. Dollar denominated liabilities.
- Losses of $10 million at The AES Corporation were primarily due to decreases in the valuation of intercompany notes receivable denominated in foreign currencies, resulting from the weakening of the Euro and British Pound during the year, partially offset by gains related to foreign currency option purchases.
- Gains of $16 million in Argentina were primarily due to a gain on a foreign currency embedded derivative related to government receivables, partially offset by losses due to the 8% devaluation of the Argentine Peso, resulting in losses at Alicura (an Argentine Peso functional currency subsidiary) associated with its U.S. Dollar denominated debt.

The Company recognized foreign currency transaction losses of $33 million for the year ended December 31, 2010. These losses consisted primarily of losses at The AES Corporation partially offset by gains in Argentina.

- Losses of $50 million at The AES Corporation were primarily due to the devaluation of notes receivable resulting from the weakening of the Euro and British Pound, and losses on foreign exchange swaps and options, partially offset by gains on cash balances and debt denominated in British Pounds.
- Gains of $12 million in Argentina were primarily due to a gain on a foreign currency embedded derivative related to government receivables, partially offset by losses due to the devaluation of the Argentine Peso by 5%, resulting in losses at Alicura (an Argentine Peso functional currency subsidiary) associated with its U.S. Dollar denominated debt.

The Company recognized foreign currency transaction gains of $35 million for the year ended December 31, 2009. These gains consisted primarily of gains in Chile, the Philippines and at The AES Corporation partially offset by losses in Kazakhstan, Colombia, Argentina and Brazil.

- Gains of $65 million in Chile were primarily due to the appreciation of the Chilean Peso of 20% resulting in gains at Gener (a U.S. Dollar functional currency subsidiary) associated with its net working capital denominated in Chilean Pesos, mainly cash and accounts receivables. This gain was partially offset by $14 million in losses on foreign currency derivatives.
- Gains of $15 million in the Philippines were primarily due to the appreciation of the Philippine Peso of 3%, resulting in gains at Masinloc (a Philippine Peso functional currency subsidiary) on the remeasurement of U.S. Dollar denominated debt.
- Gains of $13 million at The AES Corporation were primarily due to the settlement of the senior unsecured credit facility and the revaluation of notes receivable denominated in the Euro, partially offset by losses on debt denominated in British Pounds.
- Losses of $24 million in Kazakhstan were primarily due to net foreign currency transaction losses of $12 million related to energy sales denominated and fixed in the U.S. Dollar and $12 million of foreign currency transaction losses on debt and other liabilities denominated in currencies other than the Kazakh Tenge.
- Losses of $11 million in Colombia were primarily due to the appreciation of the Colombian Peso of 9%, resulting in losses at Chivor (a U.S. Dollar functional currency subsidiary) associated with its Colombian Peso denominated debt and losses on foreign currency derivatives.
- Losses of $10 million in Argentina were primarily due to the devaluation of the Argentine Peso of 10% in 2009, resulting in losses at Alicura (an Argentine Peso functional currency subsidiary) associated with its U.S. Dollar denominated debt, partially offset by derivative gains.
- Losses of $9 million in Brazil were primarily due to energy purchases made by Eletropaulo denominated in U.S. Dollar, resulting in foreign currency transaction losses of $18 million, partially offset by gains of $9 million due to the appreciation in 2009 of the Brazilian Real of 25%, resulting in gains at Sul and Uruguaiana associated with U.S. Dollar denominated liabilities.

Other non-operating expense

Other non-operating expense was $82 million, $7 million and $12 million for the years ended December 31, 2011, 2010 and 2009, respectively.

See Note 8—*Other Non-operating Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Income taxes

Income tax expense on continuing operations increased $57 million, or 10%, to $636 million in 2011. The Company's effective tax rates were 29% for 2011 and 31% for 2010.

The net decrease in the 2011 effective tax rate was primarily due to a tax benefit related to partial release of a valuation allowance against certain deferred tax assets at one of our Brazilian subsidiaries in the current period and tax expense recorded in the second quarter of 2010 relating to the CEMIG sale transaction. These items were offset by the impact of impairments recorded in the current period at certain foreign subsidiaries and the tax benefit related to a reversal of a Chilean withholding tax liability recorded in the third quarter of 2010. See Notes 8—*Other Non-Operating Expense* and 20—*Impairment Expense* for additional information regarding the current period impairments.

Income tax expense on continuing operations increased $22 million, or 4%, to $579 million in 2010. The Company's effective tax rates were 31% for 2010 and 25% for 2009.

The net increase in the 2010 effective tax rate was primarily due to expense recorded in the second quarter of 2010 relating to the CEMIG sale transaction, tax benefit recorded in 2009 upon the release of valuation allowances at certain U.S. and Brazilian subsidiaries, and $165 million of non-taxable income recorded in 2009 at Brazil as a result of the REFIS program. These items were offset by income tax benefit related to a reversal of a Chilean withholding tax liability recorded in the third quarter of 2010. Included in the net tax expense related to the CEMIG sale transaction is tax expense on the equity earnings associated with the reversal of the net long-term liability and tax benefit related to release of a valuation allowance against certain deferred tax assets.

Net equity in earnings of affiliates

Net equity in earnings of affiliates decreased $186 million, or 101%, to $(2) million in 2011. This decrease was primarily due to the sale of our interest in CEMIG during the second quarter of 2010 which resulted in a significant gain, and $72 million of impairments at AES Solar in 2011, of which our share was $36 million.

Net equity in earnings of affiliates increased $91 million, or 98%, to $184 million in 2010. This increase was primarily due to a gain recognized upon the sale of our interest in CEMIG during the second quarter of 2010, partially offset by 2009 equity in earnings of Cartagena which was accounted for as a consolidated entity in 2010 and thus reported directly within revenues and expenses.

Income from continuing operations attributable to noncontrolling interests

Income from continuing operations attributable to noncontrolling interests increased $97 million, or 10%, to $1.1 billion in 2011. This increase was primarily due to the appreciation of the Brazilian Real and increased gross margin at Gener due to increased volume. This was partially offset by lower prices at Eletropaulo primarily related to the estimated impact of the July 2011 tariff reset and lower gross margin at Sonel mainly due to the unfavorable impact of an unrealized mark-to-market derivative loss.

Income from continuing operations attributable to noncontrolling interests decreased $94 million, or 9%, to $1.0 billion in 2010. This decrease was primarily due to decreased earnings at Eletropaulo as a result of the absence of legal settlement income realized in 2009, a loss on legal settlement at Gener and reduced revenues due to decreased coal prices along with higher electricity purchases at Itabo. These decreases were partially offset by the appreciation of the Brazilian Real.

Discontinued operations

Total discontinued operations was a net loss of $11 million, $411 million and $49 million for the years ended December 31, 2011, 2010 and 2009, respectively.

See Note 22—*Discontinued Operations and Held for Sale Businesses* included in Item 8.— *Financial Statements and Supplementary Data* of this Form 10-K for further information.

Critical Accounting Estimates

The Consolidated Financial Statements of AES are prepared in conformity with GAAP, 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. AES' significant accounting policies are described in Note 1—*General and Summary of Significant Accounting Policies* to the Consolidated Financial Statements included in Item 8 of this Form 10-K.

An accounting estimate is considered critical if:

- the estimate requires management to make assumptions about matters that were highly uncertain at the time the estimate was made;
- different estimates reasonably could have been used; or
- the impact of the estimates and assumptions on financial condition or operating performance is material.

Management believes that the accounting estimates employed are appropriate and the resulting balances are reasonable; however, actual results could materially differ from the original estimates, requiring adjustments to these balances in future periods. Management has discussed these critical accounting policies with the Audit Committee, as appropriate. Listed below are the Company's most significant critical accounting estimates and assumptions used in the preparation of the Consolidated Financial Statements.

Income Taxes

We are subject to income taxes in both the United States and numerous foreign jurisdictions. Our worldwide income tax provision requires significant judgment and is based on calculations and assumptions that are subject to examination by the Internal Revenue Service and other taxing authorities. The Company and certain of its subsidiaries are under examination by relevant taxing authorities for various tax years. The Company regularly assesses the potential outcome of these examinations in each tax jurisdiction when determining the adequacy of the provision for income taxes. Accounting guidance for uncertainty in income taxes prescribes a more-likely-than-not recognition threshold. Tax reserves have been established, which the Company believes to be adequate in relation to the potential for additional assessments. Once established, reserves are adjusted only when there is more information available or when an event occurs necessitating a change to the reserves. While the Company believes that the amounts of the tax estimates are reasonable, it is possible that the ultimate outcome of current or future examinations may exceed current reserves in amounts that could be material.

Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of the existing assets and liabilities, and their respective income tax bases. The Company establishes a valuation allowance when it is more likely than not that all or a portion of a deferred tax asset will not be realized.

The Company's provision for income taxes could be adversely impacted by changes to the U.S. taxation of earnings of our foreign subsidiaries. Since 2006, the Company has benefitted from the Controlled Foreign Corporation look-through rule, originally enacted for the 2006 through 2009 tax years in the Tax Increase

Prevention and Reconciliation Act ("TIPRA") of 2005 and retroactively reinstated for the 2010 and 2011 tax years via the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010. This provision provided an exception from current U.S. taxation of certain un-repatriated cross-border payments of subsidiary dividends, interest, rents, and royalties. In determining the Company's effective tax rate for the year ended December 31, 2011, the Company has included the benefits of this provision. However, the Controlled Foreign Corporation look-through rule has not been reinstated, retroactively or otherwise, for 2012 or subsequent tax years and there can be no assurance that this provision will continue to be extended. Accordingly, if this provision is not renewed, we expect our effective tax rate to increase by amounts that could be material.

Impairments

Our accounting policies on goodwill and long-lived assets are described in detail in Note 1—*General and Summary of Significant Accounting Policies*, included in Item 8 of this Form 10-K. Goodwill is tested annually for impairment at the reporting unit level on October 1 and whenever events or circumstances indicate that it is more likely than not that the fair value of a reporting unit has been reduced below its carrying amount. A long-lived asset (asset group) will be tested for recoverability whenever events or changes in circumstances indicate that its carrying amount may not be recoverable, i.e., the future undiscounted cash flows associated with the asset are less than its carrying amount. In the event that the carrying amount of the long-lived asset (asset group) is not recoverable, an impairment evaluation is performed, in which the fair value of the asset is estimated and compared to the carrying amount. Examples of indicators that would result in an impairment test for goodwill and a recoverability test for long-lived assets include, but are not limited to, a significant adverse change in the business climate, legislation changes or a change in the extent or manner in which a long-lived asset is being used or in its physical condition. Throughout the impairment evaluation process, management makes considerable judgments; however, the fair value determination is typically the most judgmental part of an impairment evaluation.

The Company determines the fair value of a reporting unit or a long-lived asset (asset group) by applying the approaches prescribed under the fair value measurement accounting framework. Generally, the market approach and income approach are most relevant in the fair value measurement of our reporting units and long-lived assets; however, due to the lack of available relevant observable market information in many circumstances, the Company often relies on the income approach. The Company may engage an independent valuation firm to assist management with the valuation. The decision to engage an independent valuation firm considers all relevant facts and circumstances, including a cost/benefit analysis and the Company's internal valuation knowledge of the long-lived asset (asset group) or business. The Company develops the underlying assumptions consistent with its internal budgets and forecasts for such valuations. Additionally, the Company uses an internal discounted cash flow valuation model (the "DCF model"), based on the principles of present value techniques, to estimate the fair value of its reporting units or long-lived assets under the income approach. The DCF model estimates fair value by discounting our internal budgets and cash flow forecasts, adjusted to reflect market participant assumptions, to the extent necessary, at an appropriate discount rate.

Management applies considerable judgment in selecting several input assumptions during the development of our internal budgets and cash flow forecasts. Examples of the input assumptions that our budgets and forecasts are sensitive to include macroeconomic factors such as growth rates, industry demand, inflation, exchange rates, power prices and commodity prices. Whenever appropriate, management obtains these input assumptions from observable market data sources (e.g., Economic Intelligence Unit) and extrapolates the market information if an input assumption is not observable for the entire forecast period. Many of these input assumptions are dependent on other economic assumptions, which are often derived from statistical economic models with inherent limitations such as estimation differences. Further, several input assumptions are based on historical trends which often do not recur. The input assumptions most significant to our budgets and cash flows are based on expectations of macroeconomic factors which have been volatile recently. It is not uncommon that different market data sources have different views of the macroeconomic factors expectations and related assumptions. As a result, macroeconomic factors and related assumptions are often available in a narrow range; however, in some situations these ranges become wide and the use of a different set of input assumptions could produce significantly different budgets and cash flow forecasts.

A considerable amount of judgment is also applied in the estimation of the discount rate used in the DCF model. To the extent practical, inputs to the discount rate are obtained from market data sources (e.g., Bloomberg, Capital IQ, etc.). The Company selects and uses a set of publicly traded companies from the relevant industry to estimate the discount rate inputs. Management applies judgment in the selection of such companies based on its view of the most likely market participants. It is reasonably possible that the selection of a different set of likely market participants could produce different input assumptions and result in the use of a different discount rate.

Fair value of a reporting unit or a long-lived asset (asset group) is sensitive to both input assumptions to our budgets and cash flow forecasts and the discount rate. Further, estimates of long-term growth and terminal value are often critical to the fair value determination. As part of the impairment evaluation process, management analyzes the sensitivity of fair value to various underlying assumptions. The level of scrutiny increases as the gap between fair value and carrying amount decreases. Changes in any of these assumptions could result in management reaching a different conclusion regarding the potential impairment, which could be material. Our impairment evaluations inherently involve uncertainties from uncontrollable events that could positively or negatively impact the anticipated future economic and operating conditions.

Further discussion of the impairment charges recognized by the Company can be found within Note 9—*Goodwill and Other Intangible Assets,* Note 20—*Impairment Expense* and Note 8—*Other Non-operating Expense* to the Consolidated Financial Statements included in Item 8 of this Form 10-K.

Fair Value

Fair Value Hierarchy

The Company uses valuation techniques and methodologies that maximize the use of observable inputs and minimize the use of unobservable inputs. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices are not available, valuation models are applied to estimate the fair value using the available observable inputs. The valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the price transparency for the instruments or market and the instruments' complexity.

To increase consistency and enhance disclosure of the fair value of financial instruments, the fair value measurement standard includes a fair value hierarchy to prioritize the inputs used to measure fair value into three categories. An asset or liability's level within the fair value hierarchy is based on the lowest level of input significant to the fair value measurement, where Level 1 is the highest and Level 3 is the lowest. For more information regarding the fair value hierarchy, see Note 1—*General and Summary of Significant Accounting Policies* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K.

Fair Value of Financial Instruments

A significant number of the Company's financial instruments are carried at fair value with changes in fair value recognized in earnings or other comprehensive income each period. The Company makes estimates regarding the valuation of assets and liabilities measured at fair value in preparing the Consolidated Financial Statements. These assets and liabilities include short and long-term investments in debt and equity securities, included in the balance sheet line items "Short-term investments" and "Other assets (Noncurrent)", derivative assets, included in "Other current assets" and "Other assets (Noncurrent)" and derivative liabilities, included in "Accrued and other liabilities (current)" and "Other long-term liabilities". Investments are generally fair valued based on quoted market prices or other observable market data such as interest rate indices. The Company's investments are primarily certificates of deposit, government debt securities and money market funds. Derivatives are valued using observable data as inputs into internal valuation models. The Company's derivatives primarily consist of interest rate swaps, foreign currency instruments, and commodity and embedded derivatives. Additional discussion regarding the nature of these financial instruments and valuation techniques can be found in Note 4—*Fair Value* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K.

Fair Value of Nonfinancial Assets and Liabilities

Significant estimates are made in determining the fair value of long-lived tangible and intangible assets (i.e., property, plant and equipment, intangible assets and goodwill) during the impairment evaluation process. In addition, the majority of assets acquired and liabilities assumed in a business combination are required to be recognized at fair value under the relevant accounting guidance. In determining the fair value of these items, management makes several assumptions discussed in the Impairments section.

Accounting for Derivative Instruments and Hedging Activities

We enter into various derivative transactions in order to hedge our exposure to certain market risks. We primarily use derivative instruments to manage our interest rate, commodity and foreign currency exposures. We do not enter into derivative transactions for trading purposes.

In accordance with the accounting standards for derivatives and hedging, we recognize all derivatives as either assets or liabilities in the balance sheet and measure those instruments at fair value except where derivatives qualify and are designated as “normal purchase/normal sale” transactions. Changes in fair value of derivatives are recognized in earnings unless specific hedge criteria are met. Income and expense related to derivative instruments are recognized in the same category as that generated by the underlying asset or liability. See Note 6—*Derivative instruments and hedging activity* included in Item 8 of this Form 10-K for further information on the classification.

The accounting standards for derivatives and hedging enable companies to designate qualifying derivatives as hedging instruments based on the exposure being hedged. These hedge designations include fair value hedges and cash flow hedges. Changes in the fair value of a derivative that is highly effective and is designated and qualifies as a fair value hedge, are recognized in earnings as offsets to the changes in fair value of the exposure being hedged. The Company has no fair value hedges at this time. Changes in the fair value of a derivative that is highly effective and is designated as and qualifies as a cash flow hedge, are deferred in accumulated other comprehensive income and are recognized into earnings as the hedged transactions occur. Any ineffectiveness is recognized in earnings immediately. For all hedge contracts, the Company provides formal documentation of the hedge and effectiveness testing in accordance with the accounting standards for derivatives and hedging.

The fair value measurement accounting standard provides additional guidance on the definition of fair value and defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, or exit price. The fair value measurement standard requires the Company to consider and reflect the assumptions of market participants in the fair value calculation. These factors include nonperformance risk (the risk that the obligation will not be fulfilled) and credit risk, both of the reporting entity (for liabilities) and of the counterparty (for assets). Due to the nature of the Company’s interest rate swaps, which are typically associated with non-recourse debt, credit risk for AES is evaluated at the subsidiary level rather than at the Parent Company level. Nonperformance risk on the Company’s derivative instruments is an adjustment to the initial asset/liability fair value position that is derived from internally developed valuation models that utilize observable market inputs.

As a result of uncertainty, complexity and judgment, accounting estimates related to derivative accounting could result in material changes to our financial statements under different conditions or utilizing different assumptions. As a part of accounting for these derivatives, we make estimates concerning nonperformance, volatilities, market liquidity, future commodity prices, interest rates, credit ratings (both ours and our counterparty’s) and exchange rates.

The fair value of our derivative portfolio is generally determined using internal valuation models, most of which are based on observable market inputs including interest rate curves and forward and spot prices for currencies and commodities. The Company derives most of its financial instrument market assumptions from market efficient data sources (e.g., Bloomberg, Reuters 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 a financial instrument's fair value. In certain instances, the published curve may not extend through the remaining term of the contract and management must make assumptions to extrapolate the curve. Additionally, in the absence of quoted prices, we may rely on "indicative pricing" quotes from financial institutions to input into our valuation model for certain of our foreign currency swaps. These indicative pricing quotes do not constitute either a bid or ask price and therefore are not considered observable market data. For individual contracts, the use of different valuation models or assumptions could have a material effect on the calculated fair value.

Regulatory Assets and Liabilities

The Company accounts for certain of its regulated operations in accordance with the regulatory accounting standards. As a result, AES recognizes assets and liabilities that result from the regulated ratemaking process that would not be recognized under GAAP for non-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery through customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred or included in future rate initiatives. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes, recent rate orders applicable to other regulated entities and the status of any pending or potential deregulation legislation. If future recovery of costs ceases to be probable, any asset write-offs would be required to be recognized in operating income.

New Accounting Pronouncements Adopted

In 2011, the Company adopted certain new accounting pronouncements as they became effective or when we were allowed to early adopt. The adoption of these new accounting pronouncements did not have a material impact on the Company's financial position or results of operations. See Note 1—*General and Summary of Significant Accounting Policies* included in Item 8 of this Form 10-K for further information.

Accounting Pronouncements Issued But Not Yet Effective

See Note 1—*General and Summary of Significant Accounting Policies* included in Item 8 of this Form 10-K for accounting pronouncements, which were issued, but not yet effective as of December 31, 2011. The Company does not expect to have a material impact on its financial condition or results of operations as a result of the adoption of the new accounting pronouncements, which were issued, but not yet effective.

Capital Resources and Liquidity

Overview

As of December 31, 2011, the Company had unrestricted cash and cash equivalents of $1.7 billion, of which approximately $0.2 billion was held at the Parent Company and qualified holding companies, and short term investments of $1.4 billion. In addition, we had restricted cash and debt service reserves of $1.4 billion. The Company also had non-recourse and recourse aggregate principal amounts of debt outstanding of $16.1 billion and $6.5 billion, respectively. Of the approximately $2.2 billion of our short-term non-recourse debt, $900 million was presented as current because it is due in the next twelve months and $1.3 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 $305 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 material un-hedged exposure to variable interest rate debt relates to indebtedness under its senior secured credit facility. On a consolidated basis, of the Company's $16.1 billion of total non-recourse debt outstanding as of December 31, 2011, approximately $4.2 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 December 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 $351 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 December 31, 2011, we had $12 million in letters of credit outstanding, provided under the senior secured credit facility, and $261 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 December 31, 2011, the Company paid letter of credit fees ranging from 0.250% to 3.250% 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 December 31, 2011, the Company had approximately $376 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 December 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 $24 million at December 31, 2011.

Capital Expenditures

The Company spent $2.5 billion, $2.3 billion and $2.5 billion on capital expenditures in 2011, 2010 and 2009, respectively. A significant majority of these costs were funded with non-recourse debt consistent with our financial strategy. At December 31, 2011, the Company had a total of $1.4 billion of availability under long-term non-recourse construction credit facilities. As more fully described in *Key Trends and Uncertainties* above, we have taken steps to decrease the amount of new discretionary capital spending. We expect to continue funding projects that are currently in the construction phase using existing capital provided by these non-recourse credit facilities as supplemented by internally generated cash flows, Parent Company liquidity, contribution from existing or new partners and other funding sources. As a result, property, plant and equipment and long-term non-recourse debt are expected to increase over the next few years even though the rate of discretionary spending has decreased. While we believe we have the resources to continue funding the projects in construction, there can be no assurances that we will continue to fund all these existing construction efforts.

As of December 31, 2011, the Company had $9 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 2012. 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.

Environmental Capital Expenditures

The Company continues to assess the possible need for capital expenditures associated with international, federal, regional and state regulation of GHG emissions from electric power generation facilities. Currently in the United States there is no Federal legislation establishing mandatory GHG emissions reduction programs (including CO_2) affecting the electric power generating 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 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 CAA. The EPA regulations and any subsequent Federal legislation, if enacted, may place significant costs on GHG emissions from fossil fuel-fired electric power generation facilities, particularly coal-fired facilities, and in order to comply, CO_2 emitting facilities may be required to purchase additional GHG emissions allowances or offsets under cap-and-trade programs, pay a carbon tax or install new emission reduction equipment to capture or reduce the amount of GHG emitted from the facilities, in the event that reliable technology to do so is developed. The capital expenditures required to comply with any future GHG legislation or any GHG regulations could be significant and unless such costs can be passed on to customers or counterparties, such regulations could impair the profitability of some of the electric power generation facilities operated by our subsidiaries or render certain of them uneconomical to operate, either of which could have a material adverse effect on our consolidated results of operations and financial condition.

With respect to our operations outside the United States, certain of the businesses operated by the Company's subsidiaries are subject to compliance with EU ETS and the Kyoto Protocol in certain countries and other country-specific programs to regulate GHG emissions. To date, compliance with the Kyoto Protocol and EU ETS has not had a material adverse effect on the Company's consolidated results of operations, financial condition and cash flows because of, among other factors, the cost of GHG emission allowances and/or the ability of our businesses to pass the cost of purchasing such allowances on to customers or counterparties. However, in the event that such counterparties or regulatory authorities challenge our ability to pass these costs on, there can be no assurance that the Company and/or the relevant subsidiary would prevail in any such dispute. Furthermore, even if the Company and/or the relevant subsidiary does prevail, it would be subject to the cost and administrative burden associated with such dispute.

As discussed in Item 1.—Business—Regulatory Matters—*Environmental and Land Use Regulations* in this Form 10-K, in the United States there presently is no federal legislation establishing mandatory GHG emission reduction programs. In 2011, the Company's subsidiaries operated businesses which had total approximate CO_2 emissions of 74 million metric tons (ownership adjusted). Approximately 37.5 million metric tons of the 74 million metric tons were emitted in the U.S. (both figures ownership adjusted). Approximately 8.3 million metric tons were emitted in U.S. states participating in the RGGI. We believe that legislative or regulatory actions, if enacted, may require a material increase in capital expenditures at our subsidiaries.

In the future the actual impact on our subsidiaries' capital expenditures from any potential federal program to regulate and reduce GHG emissions, if enacted, and the state and regional programs developed or in the process of development, or any EPA regulation of GHG emissions, will depend on a number of factors, including among others, the GHG reductions required under any such legislation or regulations, the cost of emissions reduction equipment, the price and availability of offsets, the extent to which our subsidiaries would be entitled to receive GHG emission allowances without having to purchase them, the quantity of allowances which our subsidiaries would have to purchase, the price of allowances, and our subsidiaries' ability to recover or pass-through costs incurred to comply with any legislative or regulatory requirements that are ultimately imposed and the use of market-based compliance options such as cap-and-trade programs.

Income Taxes

We recognized tax expense of $636 million for the year ended December 31, 2011, while our cash payments for income taxes, net of refunds, totaled $971 million. The difference resulted primarily from cash payments related to the sale of two telecommunication companies in Brazil, the tax expense on which was recorded in gain from disposal of discontinued businesses. Tax expense was further impacted by a partial valuation allowance release at one of our Brazilian subsidiaries.

Consolidated Cash Flows

At December 31, 2011, cash and cash equivalents decreased $815 million from December 31, 2010 to $1.7 billion. The decrease in cash and cash equivalents was due to $2.9 billion of cash provided by operating activities, $4.9 billion of cash used for investing activities, $1.4 billion of cash provided by financing activities, an unfavorable effect of foreign currency exchange rates on cash of $122 million and an $83 million increase in cash of discontinued and held for sale businesses.

At December 31, 2010, cash and cash equivalents increased $766 million from December 31, 2009 to $2.5 billion. The increase in cash and cash equivalents was due to $3.5 billion of cash provided by operating activities, $2.0 billion of cash used for investing activities, $706 million of cash used for financing activities, favorable effect of foreign currency exchange rates on cash of $8 million and a $39 million decrease in cash of discontinued and held for sale businesses.

				$ Change	
	2011	2010	2009	2011 vs. 2010	2010 vs. 2009
			(in millions)		
Net cash provided by (used in) operating activities	$ 2,884	$ 3,465	$ 2,211	$ (581)	$ 1,254
Net cash provided by (used in) investing activities	$(4,906)	$(2,040)	$(1,917)	$(2,866)	$ (123)
Net cash provided by (used in) financing activities	$ 1,412	$ (706)	$ 610	$ 2,118	$(1,316)

Operating Activities

Net cash provided by operating activities decreased $581 million, or 17%, to $2.9 billion during 2011 compared to 2010. This net decrease was primarily due to the following:

- a decrease of $354 million at our Latin American utilities businesses primarily driven by our businesses in Brazil due to higher income tax payments of which $84 million is due to the sale of Brazil Telecom in October 2011, for which the pre-tax net sales proceeds of $890 million are recorded in cash flows from investing activities, and a one-time cash savings of $107 million mainly related to the utilization of a tax credit received as a result of the REFIS program in 2010, lower accounts receivable collections at Eletropaulo and higher payments for energy purchases, operation and maintenance expenses and pension contributions. These impacts were partially offset by higher accounts receivable collections at Sul;
- a decrease of $145 million at our North America generation businesses primarily due to reduced operations in New York prior to its deconsolidation in December 2011 and higher working capital requirements at Puerto Rico, partially offset by the deconsolidation of Thames; and
- a decrease of $56 million at Masinloc in the Philippines due to lower gross margin.

Although net income for the period increased $471 million for 2011, net cash provided by operating activities decreased $581 million during 2011. Included in net income for each period are items such as impairments and losses from discontinued operations, which have both decreased in 2011, which have contributed to the increase in net income for the period, but are largely excluded from net cash provided by operating activities because they are non-cash in nature or the underlying cash activity is appropriately classified as an investing or financing activity. Also, net cash provided by operating activities in 2010 was impacted by certain non-recurring items, as discussed above, which were not expected to recur in 2011. The Company does not expect a further decrease in net cash provided by operating activities to continue in 2012, when compared to 2011, however, it can provide no assurance that such trend will not continue.

Investing Activities

Net cash used for investing activities increased $2.9 billion, or 140%, to $4.9 billion during 2011 compared to 2010. This increase was largely attributable to the following:

- an increase of $3.3 billion in acquisitions, net of cash acquired, primarily due to the $3.4 billion acquisition of DPL in November 2011 and the $149 million acquisition of our equity investment in Entek in February and May 2011. These increases were offset by the acquisitions of Ballylumford in Northern Ireland and our equity investment in JHRH for $138 million and $35 million, respectively, during 2010;
- an increase of $228 million in debt service reserves and other assets during 2011 compared to the 2010. During 2011, $284 million of funds were transferred to debt service reserves and other assets primarily related to the collateralization for a letter of credit of $222 million at the Parent Company for the Mong Duong project in Vietnam, $32 million for a construction retainage fee at Panama and $22 million at Kilroot. These increases were partially offset by a transfer out of debt service reserves and other assets for payment of rent of $33 million in New York;
- a decrease of $132 million in proceeds from loan repayments during 2011. In 2010, we received $132 million in proceeds related to the repayment of the loan receivable from a wind development project in Brazil. There were no proceeds from loan repayments in 2011; and
- an increase of $120 million in capital expenditures to $2.4 billion primarily due to increases in capital expenditures of $135 million for the Mong Duong project, and net increases of $128 million and $32 million at our Brazilian and African subsidiaries, respectively. These increases were partially offset by decreases in capital expenditures of $110 million at Maritza in Bulgaria and $86 million at Gener.

These increases were partially offset by:

- an increase of $332 million in proceeds from the sale of businesses primarily due to the $890 million in net cash received for the Brazil Telecom sale in October 2011 and $36 million received from the sale of a 49% equity interest in Mong Duong. These were offset by a decrease in proceeds of $496 million related to the 2010 sale of our businesses in the Middle East as well as 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 the 2008 sale of Ekibastuz and Maikuben;
- an increase of $224 million from the sale of short-term investments, net of purchases, during 2011, primarily due to the increase of $135 million and $92 million at Gener and our Brazilian subsidiaries, respectively, due to the use of such investments to fund dividend distributions; and
- an increase of $199 million of proceeds received from collection of a performance bond to compensate for construction delays at Maritza in Bulgaria. There were no proceeds from performance bonds in 2010.

Financing Activities

Net cash provided by financing activities increased $2.1 billion, or 300%, to $1.4 billion during 2011 compared to net cash used for financing activities of $706 million during 2010. This increase was primarily attributable to the following:

- an increase of $3.3 billion in proceeds from issuances of recourse and non-recourse debt, primarily due to a $3.3 billion increase at the Parent Company used to partially fund the acquisition of DPL, as well as $625 million at IPALCO mostly used to refinance debt, offset by a decrease of $895 million at our Brazilian subsidiaries;

- an increase of $359 million of net borrowings under revolving credit facilities primarily due to increases of $295 million at the Parent Company to fund, in part, the acquisition of DPL, $35 million at Alicura, $14 million at IPALCO and a net increase of $11 million attributable to discontinued operations;
- a decrease of $166 million in repayments of recourse and non-recourse debt, attributable to decreases of $437 million at the Parent Company, $294 million at our Brazilian subsidiaries, $171 million at Andres, $133 million at Itabo, $103 million at Chigen, $42 million in New York, $23 million at our European Wind generation projects and $19 million at Kilroot. These decreases were partially offset by increases of $559 million at IPALCO, $337 million at Gener, $133 million at Sonel, $55 million at Maritza, and $20 million at Southland; and
- a decrease of $157 million in distributions to noncontrolling interests, primarily due to $97 million related to distributions in connection with the sale of discontinued operations in the Middle East made in 2010, $69 million at our Armenia Mountain wind generation project, $53 million at our Brazilian subsidiaries, offset by an increase of $48 million at Gener.

These increases were partially offset by:

- a $1.6 billion issuance of common stock net of transaction costs to China Investment Corporation in 2010;
- an increase of $180 million in purchases of treasury stock under the Company's common stock repurchase plan; and
- an increase of $141 million in payments for financing fees primarily due to the issuance of debt at the Parent Company, Mong Duong and Gener.

Contractual Obligations

A summary of our contractual obligations, commitments and other liabilities as of December 31, 2011 is presented in the table below, which excludes any businesses classified as discontinued operations or held-for-sale (in millions):

Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**5 years and more**	**Other**	**Footnote Reference[9]**
Debt Obligations[1]	$22,501	$ 2,446	$ 3,557	$ 4,226	$12,272	$—	11
Interest Payments on Long-Term Debt[2]	10,786	1,502	2,755	2,233	4,296	—	n/a
Capital Lease Obligations[3]	178	14	21	18	125	—	12
Operating Lease Obligations[4]	1,007	57	112	108	730	—	12
Electricity Obligations[5]	35,107	2,800	4,446	3,974	23,887	—	12
Fuel Obligations[6]	10,156	1,980	1,977	1,324	4,875	—	12
Other Purchase Obligations[7]	16,075	1,853	2,708	1,896	9,618	—	12
Other Long-term Liabilities Reflected on AES's Consolidated Balance Sheet under GAAP[8]	887	7	225	90	390	175	n/a
Total	$96,697	$10,659	$15,801	$13,869	$56,193	$175	

(1) Includes recourse and non-recourse debt presented on the Consolidated Balance Sheet. Non-recourse debt borrowings are not a direct obligation of AES, the Parent Company. Recourse debt represents the direct borrowings of AES, the Parent Company. See Note 11—*Debt* to the Consolidated Financial Statements included in Item 8 of this Form 10-K which provides additional disclosure regarding these obligations. These amounts exclude capital lease obligations which are included in the capital lease category, see (3) below.

(2) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2011 and do not reflect anticipated future refinancing, early redemptions or new debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2011.
(3) Several AES subsidiaries have leases for operating and office equipment and vehicles that are classified as capital leases within Property, Plant and Equipment. Minimum contractual obligations include $106 million of imputed interest.
(4) The Company was obligated under long-term noncancelable operating leases, primarily for office rental and site leases.
(5) Operating subsidiaries of the Company have entered into contracts for the purchase of electricity from third parties.
(6) Operating subsidiaries of the Company have entered into fuel purchase contracts subject to termination only in certain limited circumstances.
(7) Amounts relate to other contractual obligations where the Company has an enforceable and legally binding agreement to purchase goods or services that specifies all significant terms, including: quantity, pricing, and approximate timing. These amounts include planned capital expenditures that are contractually obligated.
(8) These amounts do not include current liabilities on the Consolidated Balance Sheet except for the current portion of uncertain tax obligations. Noncurrent uncertain tax obligations are reflected in the "Other" column of the table above as the Company is not able to reasonably estimate the timing of the future payments. In addition, the amounts do not include: (1) regulatory liabilities (See Note 10—*Regulatory Assets and Liabilities*), (2) contingencies (See Note 13—*Contingencies*), (3) pension and other post retirement employee benefit liabilities (see Note 14—*Benefit Plans*) or (4) any taxes (See Note 21—Income Taxes) except for uncertain tax obligations, as the Company is not able to reasonably estimate the timing of future payments. See the indicated notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K for additional information on the items excluded. Derivatives (See Note 6—*Derivative Instruments and Hedging Activities*) and incentive compensation are excluded as the Company is not able to reasonably estimate the timing or amount of the future payments.
(9) For further information see the note referenced below in Item 8.—*Financial Statements and Supplementary Data*.

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 Consolidated Statements of Cash Flows and the Parent Only Unconsolidated Statements of Cash Flows in Schedule I of this Form 10-K. 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;
- Parent Company overhead and development costs; and
- dividends on our common stock.

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 December 31, 2011 and 2010 as follows:

Parent Company Liquidity	**2011**	**2010**
	(in millions)	
Cash and cash equivalents	$ 1,710	$ 2,525
Less: Cash and cash equivalents at subsidiaries	(1,510)	(1,403)
Parent and qualified holding companies cash and cash equivalents	200	1,122
Commitments under Parent credit facilities	800	800
Less: Letters of credit under the credit facilities	(12)	(85)
Less: Borrowings under the credit facilities	(295)	—
Borrowings available under Parent credit facilities	493	715
Total Parent Company Liquidity	$ 693	$ 1,837

The decrease in Parent Company Liquidity is primarily driven by the closing of the DPL Inc. acquisition in the fourth quarter of 2011 as well as new investments in Vietnam and Turkey.

Recourse Debt Transactions:

During the year ended December 31, 2011, the Company issued recourse debt of $2.05 billion as outlined below. The proceeds of the debt were used to partially finance the Company's acquisition of DPL as discussed further in Note 23—*Acquisitions and Dispositions*.

On May 27, 2011, the Company secured a $1.05 billion term loan under a senior secured credit facility (the "senior secured term loan"). The senior secured term loan bears annual interest, at the Company's option, at a variable rate of LIBOR plus 3.25% or Base Rate plus 2.25%, and matures in 2018. The senior secured term loan is subject to certain customary representations, covenants and events of default.

On June 15, 2011, the Company issued $1 billion aggregate principal amount of 7.375% senior unsecured notes maturing July 1, 2021 (the "7.375% 2021 Notes"). Upon a change of control, the Company must offer to repurchase the 7.375% 2021 Notes at a price equal to 101% of principal, plus accrued and unpaid interest. The 7.375% 2021 Notes are also subject to certain covenants restricting the ability of the Company to incur additional secured debt; to enter into sale-lease back transactions; to consolidate, merge, convey or transfer substantially all of its assets; as well as other covenants and events of default that are customary for debt securities similar to the 7.375% 2021 Notes. The Company entered into interest rate locks in May 2011 to hedge the risk of changes in LIBOR until the issuance of the 7.375% 2021 Notes. The Company paid $24 million to settle those interest rate locks as of June 15, 2011. The payment was recognized in accumulated other comprehensive loss and is being amortized over the life of the 7.375% 2021 Notes as an adjustment to interest expense using the effective yield method.

Recourse Debt:

Our recourse debt at year-end was approximately $6.5 billion and $4.6 billion in 2011 and 2010, respectively. The following table sets forth our Parent Company contingent contractual obligations as of December 31, 2011:

Contingent contractual obligations	Amount	Number of Agreements	Maximum Exposure Range for Each Agreement
	(in millions)		(in millions)
Guarantees	$351	22	<$1 - $53
Letters of credit under the senior secured credit facility	12	11	<$1 - $7
Cash collateralized letters of credit	261	13	<$1 - $221
Total	$624	46	

As of December 31, 2011, the Company had $9 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 2012. 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.

We have indicated our intent to declare a dividend in 2012. While we believe we will have sufficient liquidity to do so, we can provide no assurance we will be able to declare a dividend at the amount indicated, if at all.

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 this 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 December 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 Consolidated Balance Sheets amounts to $2.2 billion. The portion of current debt related to such defaults was $1.3 billion at December 31, 2011, all of which was non-recourse debt related to three subsidiaries—Maritza, Sonel and Kelanitissa.

None of the subsidiaries that are currently in default are subsidiaries that met the applicable definition of materiality under AES's corporate debt agreements as of December 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.

Non-Recourse Debt Transactions:

On October 3, 2011, Dolphin Subsidiary II, Inc. ("Dolphin II"), a newly formed, wholly-owned special purpose indirect subsidiary of AES, entered into an indenture (the "Indenture") with Wells Fargo Bank, N.A. (the "Trustee") as part of its issuance of $450 million aggregate principal amount of 6.50% senior notes due 2016 (the "2016 Notes") and $800 million aggregate principal amount of 7.25% senior notes due 2021 (the "7.25% 2021 Notes", together with the 2016 Notes, the "notes") to finance the acquisition (the "Acquisition") of DPL. Upon closing of the acquisition on November 28, 2011, Dolphin II was merged into DPL with DPL being the surviving entity and obligor. The 2016 Notes and the 7.25% 2021 Notes are included under "Notes and bonds" in the non-recourse detail table above. See Note 23—*Acquisitions and Dispositions* for further information.

Interest on the 2016 Notes and the 7.25% 2021 Notes accrues at a rate of 6.50% and 7.25% per year, respectively, and is payable on April 15 and October 15 of each year, beginning April 15, 2012. Prior to September 15, 2016 with respect to the 2016 Notes and July 15, 2021 with respect to the 7.25% 2021 Notes, DPL may redeem some or all of the 2016 Notes or 7.25% 2021 Notes at par, plus a "make-whole" amount set forth in the Indenture and accrued and unpaid interest. At any time on or after September 15, 2016 or July 15, 2021 with respect to the 2016 Notes and 7.25% 2021 Notes, respectively, DPL may redeem some or all of the 2016 Notes or 7.25% 2021 Notes at par plus accrued and unpaid interest. The proceeds from issuance of the notes were used to partially finance the DPL acquisition.

ITEM 7A. 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 7A 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 7A. 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*" of this 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 2012, we project pre-tax earnings exposure would be approximately $40 million for a $10/ton move in coal, $30 million for a $10/barrel move in oil and $40 million for a $1/MMBTU move in natural gas. 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 the 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, regional competition 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 and DPL sell 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. Additionally, at DPL, open access allows our retail customers to switch to alternative suppliers, falling energy prices may increase the rate at which our customers switch to alternative suppliers.

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. While Gener has been adding coal-fired generation to its portfolio under long-term power purchase agreements, a small amount of efficient generation is sold into the spot market. 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. At our Ballylumford facility, NIAUR, the regulator, has the right to terminate the PPA, which would impact our commodity exposure. Our operations in Turkey are sensitive to the spread between power and natural gas prices, which have historically been linked to oil. As a result of these relationships, falling oil prices could compress margins realized at the business.

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 2011, we entered into hedges to partially mitigate the exposure of earnings translated into the U.S. Dollar to foreign exchange volatility. As of December 31, 2011, assuming a 10% U.S. Dollar appreciation, pre-tax earnings attributable to foreign subsidiaries exposed to movement in the exchange rate of the Argentine Peso, Brazilian Real, Philippine Peso and Euro (the earnings attributable to the subsidiaries exposed to the 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 is projected to be approximately $10 million, $30 million, $10 million and $15 million, respectively, for 2012. These numbers have been produced by applying a one-time 10% U.S. Dollar appreciation to forecasted exposed pre-tax earnings for 2012 coming from the respective subsidiaries exposed to the currencies listed above, 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 December 31, 2011, the portfolio's pre-tax earnings exposure for 2012 to a 100 basis point increase in Brazilian Real, British Pound, Euro, Indian Rupee, Kazakhstani Tenge, Philippine Peso, Ukranian Hryvna, and U.S. Dollar interest rates would be approximately $25 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, Euro, Indian Rupee, Kazakhstani Tenge, Philippine Peso, Ukranian Hryvna, 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 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of The AES Corporation:

We have audited the accompanying consolidated balance sheets of The AES Corporation as of December 31, 2011 and 2010, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedules listed in the index at Item 15(a). These financial statements and schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedules based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of The AES Corporation at December 31, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, in 2010 The AES Corporation changed its method of accounting for the consolidation of variable interest entities with the adoption of amendments to Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 810, *Consolidation*, and its method of accounting for transfers and servicing of financial assets with the adoption of the amendments to FASB ASC 860, *Transfers and Servicing*, both effective January 1, 2010.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), The AES Corporation's internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

McLean, Virginia
February 24, 2012

THE AES CORPORATION

CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2011 AND 2010

	2011	2010
	(in millions, except share and per share data)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 1,710	$ 2,525
Restricted cash	484	404
Short-term investments	1,356	1,718
Accounts receivable, net of allowance for doubtful accounts of $273 and $295, respectively	2,547	2,256
Inventory	789	552
Receivable from affiliates	7	27
Deferred income taxes—current	454	300
Prepaid expenses	158	215
Other current assets	1,576	1,024
Current assets of discontinued and held for sale businesses	147	425
Total current assets	9,228	9,446
NONCURRENT ASSETS		
Property, Plant and Equipment:		
Land	1,095	1,124
Electric generation, distribution assets and other	31,948	26,514
Accumulated depreciation	(9,145)	(8,643)
Construction in progress	1,833	4,434
Property, plant and equipment, net	25,731	23,429
Other Assets:		
Investments in and advances to affiliates	1,422	1,320
Debt service reserves and other deposits	916	652
Goodwill	3,733	1,271
Other intangible assets, net of accumulated amortization of $164 and $151, respectively	566	448
Deferred income taxes—noncurrent	715	589
Other noncurrent assets	2,340	1,937
Noncurrent assets of discontinued and held for sale businesses	682	1,419
Total other assets	10,374	7,636
TOTAL ASSETS	$45,333	$40,511
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 2,020	$ 1,988
Accrued interest	331	257
Accrued and other liabilities	3,419	2,493
Non-recourse debt—current, including $158 and $1,118, respectively, related to variable interest entities	2,152	2,533
Recourse debt—current	305	463
Current liabilities of discontinued and held for sale businesses	219	331
Total current liabilities	8,446	8,065
LONG-TERM LIABILITIES		
Non-recourse debt—noncurrent, including $1,417 and $1,473, respectively, related to variable interest entities	13,936	11,643
Recourse debt—noncurrent	6,180	4,149
Deferred income taxes—noncurrent	1,328	892
Pension and other post-retirement liabilities	1,729	1,505
Other long-term liabilities	3,119	2,566
Long-term liabilities of discontinued and held for sale businesses	788	1,218
Total long-term liabilities	27,080	21,973
Commitments and Contingencies (see Notes 12 and 13)		
Cumulative preferred stock of subsidiaries	78	60
EQUITY		
THE AES CORPORATION STOCKHOLDERS' EQUITY		
Common stock ($0.01 par value, 1,200,000,000 shares authorized; 807,573,277 issued and 765,186,316 outstanding at December 31, 2011 and 804,894,313 issued and 787,607,240 outstanding at December 31, 2010)	8	8
Additional paid-in capital	8,507	8,444
Retained earnings	678	620
Accumulated other comprehensive loss	(2,758)	(2,383)
Treasury stock, at cost (42,386,961 and 17,287,073 shares at December 31, 2011 and 2010, respectively	(489)	(216)
Total The AES Corporation stockholders' equity	5,946	6,473
NONCONTROLLING INTERESTS	3,783	3,940
Total equity	9,729	10,413
TOTAL LIABILITIES AND EQUITY	$45,333	$40,511

See Accompanying Notes to these Consolidated Financial Statements

THE AES CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS
YEARS ENDED DECEMBER 31, 2011, 2010, AND 2009

	2011	2010	2009
	(in millions, except per share amounts)		
Revenue:			
Regulated	$ 9,504	$ 8,910	$ 7,601
Non-Regulated	7,770	6,918	5,509
Total revenue	17,274	15,828	13,110
Cost of Sales:			
Regulated	(7,134)	(6,532)	(5,542)
Non-Regulated	(6,006)	(5,360)	(4,211)
Total cost of sales	(13,140)	(11,892)	(9,753)
Gross margin	4,134	3,936	3,357
General and administrative expenses	(391)	(392)	(339)
Interest expense	(1,603)	(1,503)	(1,461)
Interest income	400	408	344
Other expense	(156)	(234)	(104)
Other income	149	100	459
Gain on sale of investments	8	—	131
Goodwill impairment	(17)	(21)	(122)
Asset impairment expense	(225)	(389)	(20)
Foreign currency transaction gains (losses)	(38)	(33)	35
Other non-operating expense	(82)	(7)	(12)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES AND EQUITY IN EARNINGS OF AFFILIATES	2,179	1,865	2,268
Income tax expense	(636)	(579)	(557)
Net equity in earnings (losses) of affiliates	(2)	184	93
INCOME FROM CONTINUING OPERATIONS	1,541	1,470	1,804
Income (loss) from operations of discontinued businesses, net of income tax expense (benefit) of $(27), $(270) and $45, respectively	(97)	(475)	101
Gain (loss) from disposal of discontinued businesses, net of income tax expense (benefit) of $300, $132 and $0, respectively	86	64	(150)
NET INCOME	1,530	1,059	1,755
Noncontrolling interests:			
Less: Income from continuing operations attributable to noncontrolling interests	(1,083)	(986)	(1,080)
Less: Income from discontinued operations attributable to noncontrolling interests	(389)	(64)	(17)
Total net income attributable to noncontrolling interests	(1,472)	(1,050)	(1,097)
NET INCOME ATTRIBUTABLE TO THE AES CORPORATION	$ 58	$ 9	$ 658
BASIC EARNINGS (LOSS) PER SHARE:			
Income from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ 0.59	$ 0.63	$ 1.09
Discontinued operations attributable to The AES Corporation common stockholders, net of tax	(0.52)	(0.62)	(0.10)
NET INCOME ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$ 0.07	$ 0.01	$ 0.99
DILUTED EARNINGS (LOSS) PER SHARE:			
Income from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ 0.59	$ 0.63	$ 1.08
Discontinued operations attributable to The AES Corporation common stockholders, net of tax	(0.52)	(0.62)	(0.10)
NET INCOME ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$ 0.07	$ 0.01	$ 0.98
AMOUNTS ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS:			
Income from continuing operations, net of tax	$ 458	$ 484	$ 724
Discontinued operations, net of tax	(400)	(475)	(66)
Net income	$ 58	$ 9	$ 658

See Accompanying Notes to these Consolidated Financial Statements

THE AES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
YEARS ENDED DECEMBER 31, 2011, 2010, AND 2009

	2011	2010	2009
		(in millions)	
OPERATING ACTIVITIES:			
Net income	$ 1,530	$ 1,059	$ 1,755
Adjustments to net income:			
Depreciation and amortization	1,262	1,178	1,049
(Gain) loss from sale of investments and impairment expense	386	1,313	57
(Gain) loss on disposal and impairment write-down—discontinued operations	(388)	(209)	150
Provision for deferred taxes	(199)	(418)	15
Contingencies	30	37	(122)
(Gain) loss on the extinguishment of debt	62	34	(6)
Undistributed gain from sale of equity method investment	—	(106)	—
Other	149	(31)	(99)
Changes in operating assets and liabilities, net of effects of acquisitions:			
(Increase) decrease in accounts receivable	(236)	(98)	62
(Increase) decrease in inventory	(141)	10	(34)
(Increase) decrease in prepaid expenses and other current assets	(7)	385	147
(Increase) decrease in other assets	(403)	(248)	(177)
Increase (decrease) in accounts payable and other current liabilities	322	136	(308)
Increase (decrease) income taxes and other income tax payables, net	166	166	88
Increase (decrease) in other liabilities	351	257	(366)
Net cash provided by operating activities	2,884	3,465	2,211
INVESTING ACTIVITIES:			
Capital expenditures	(2,430)	(2,310)	(2,520)
Acquisitions—net of cash acquired	(3,562)	(254)	—
Proceeds from the sale of businesses, net of cash sold	927	595	2
Proceeds from the sale of assets	117	23	17
Sale of short-term investments	6,075	5,786	4,526
Purchase of short-term investments	(5,860)	(5,795)	(4,248)
(Increase) decrease in restricted cash	61	(104)	302
(Increase) decrease in debt service reserves and other assets	(284)	(56)	185
Affiliate advances and equity investments	(155)	(97)	(155)
Proceeds from loan repayments	—	132	—
Proceeds from performance bond	199	—	—
Other investing	6	40	(26)
Net cash used in investing activities	(4,906)	(2,040)	(1,917)
FINANCING ACTIVITIES:			
Issuance of common stock	—	1,567	—
Borrowings under the revolving credit facilities, net	437	78	11
Issuance of recourse debt	2,050	—	503
Issuance of non-recourse debt	3,218	1,940	1,997
Repayments of recourse debt	(476)	(914)	(154)
Repayments of non-recourse debt	(2,217)	(1,945)	(1,008)
Payments for financing fees	(202)	(61)	(91)
Distributions to noncontrolling interests	(1,088)	(1,245)	(846)
Contributions from noncontrolling interests	6	—	190
Financed capital expenditures	(31)	(23)	(18)
Purchase of treasury stock	(279)	(99)	—
Other financing	(6)	(4)	26
Net cash (used in) provided by financing activities	1,412	(706)	610
Effect of exchange rate changes on cash	(122)	8	22
(Increase) decrease in cash of discontinued and held for sale businesses	(83)	39	(18)
Total increase (decrease) in cash and cash equivalents	(815)	766	908
Cash and cash equivalents, beginning	2,525	1,759	851
Cash and cash equivalents, ending	$ 1,710	$ 2,525	$ 1,759
SUPPLEMENTAL DISCLOSURES:			
Cash payments for interest, net of amounts capitalized	$ 1,442	$ 1,462	$ 1,395
Cash payments for income taxes, net of refunds	$ 971	$ 698	$ 484
SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES:			
Assets acquired in noncash asset exchange	$ 20	$ 42	$ 111

See Accompanying Notes to these Consolidated Financial Statements

THE AES CORPORATION

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
YEARS ENDED DECEMBER 31, 2011, 2010, AND 2009

	THE AES CORPORATION STOCKHOLDERS								
	Common Stock Shares	Common Stock Amount	Treasury Stock Shares	Treasury Stock Amount	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Consolidated Comprehensive Income
						(in millions)			
Balance at January 1, 2009	673.5	$ 7	10.7	$(144)	$6,832	$ (8)	$(3,018)	$ 3,358	
Net income	—	—	—	—	—	658	—	1,097	$1,755
Change in fair value of available-for-sale securities, net of income tax	—	—	—	—	—	—	6	—	6
Foreign currency translation adjustment, net of income tax	—	—	—	—	—	—	271	471	742
Change in unfunded pensions obligation, net of income tax	—	—	—	—	—	—	(23)	(116)	(139)
Change in derivative fair value, net of income tax	—	—	—	—	—	—	40	33	73
Other comprehensive income									682
Total comprehensive income									$2,437
Capital contributions from noncontrolling interests	—	—	—	—	—	—	—	195	
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(825)	
Disposition of businesses	—	—	—	—	—	—	—	(8)	
Issuance of treasury stock	—	—	(1.2)	18	(20)	—	—	—	
Issuance of common stock under benefit plans and exercise of stock options, net of income tax	3.7	—	—	—	18	—	—	—	
Stock compensation	—	—	—	—	38	—	—	—	
Balance at December 31, 2009	677.2	$ 7	9.5	$(126)	$6,868	$650	$(2,724)	$ 4,205	
Net income	—	—	—	—	—	9	—	1,050	$1,059
Change in fair value of available-for-sale securities, net of income tax	—	—	—	—	—	—	(5)	—	(5)
Foreign currency translation adjustment, net of income tax	—	—	—	—	—	—	486	124	610
Change in unfunded pensions obligation, net of income tax	—	—	—	—	—	—	(22)	(66)	(88)
Change in derivative fair value, net of income tax	—	—	—	—	—	—	(80)	—	(80)
Other comprehensive income (as restated)									437
Total comprehensive income (as restated)									$1,496
Cumulative effect of consolidation of entities under variable interest entity accounting guidance	—	—	—	—	—	(47)	(38)	15	
Cumulative effect of deconsolidation of entities under variable interest entity accounting guidance	—	—	—	—	—	1	—	—	
Capital contributions from noncontrolling interests	—	—	—	—	—	—	—	35	
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(1,220)	
Disposition of businesses	—	—	—	—	—	—	—	(208)	
Acquisition of treasury stock	—	—	8.4	(99)	—	—	—	—	
Issuance of common stock	125.5	1	—	—	1,566	—	—	—	
Issuance of common stock under benefit plans and exercise of stock options, net of income tax	2.2	—	(0.6)	9	9	—	—	—	
Stock compensation	—	—	—	—	26	—	—	—	
Changes in the carrying amount of redeemable stock of subsidiaries	—	—	—	—	—	7	—	—	
Acquisition of subsidiary shares from noncontrolling interests	—	—	—	—	(25)	—	—	5	
Balance at December 31, 2010	804.9	$ 8	17.3	$(216)	$8,444	$620	$(2,383)	$ 3,940	
Net income	—	—	—	—	—	58	—	1,472	$1,530
Change in fair value of available-for-sale securities, net of income tax	—	—	—	—	—	—	(1)	—	(1)
Foreign currency translation adjustment, net of income tax	—	—	—	—	—	—	(143)	(153)	(296)
Change in unfunded pensions obligation, net of income tax	—	—	—	—	—	—	(41)	(169)	(210)
Change in derivative fair value, net of income tax	—	—	—	—	—	—	(190)	(52)	(242)
Other comprehensive income									(749)
Total comprehensive income									$ 781
Capital contributions from noncontrolling interests	—	—	—	—	—	—	—	8	
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(1,254)	
Disposition of businesses	—	—	—	—	—	—	—	(27)	
Acquisition of treasury stock	—	—	25.5	(279)	—	—	—	—	
Issuance of common stock under benefit plans and exercise of stock options, net of income tax	2.7	—	(0.4)	6	18	—	—	—	
Stock compensation	—	—	—	—	26	—	—	—	
Net gain on sale of subsidiary shares to noncontrolling interests	—	—	—	—	19	—	—	—	
Sale of subsidiary shares to noncontrolling interests	—	—	—	—	—	—	—	16	
Acquisition of subsidiary shares from noncontrolling interests	—	—	—	—	—	—	—	2	
Balance at December 31, 2011	807.6	$ 8	42.4	$(489)	$8,507	$678	$(2,758)	$ 3,783	

See Accompanying Notes to these Consolidated Financial Statements

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2011, 2010, AND 2009

1. GENERAL AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The AES Corporation is a holding company (the "Parent Company") that through its subsidiaries and affiliates, (collectively, "AES" or "the Company") operates a geographically diversified portfolio of electricity generation and distribution businesses. Generally, given this holding company structure, the liabilities of the individual operating entities are not recourse to the parent and are isolated to the operating entities. Most of our operating entities are structured as limited liability entities, which limit the liability of shareholders. The structure is generally the same regardless of whether a subsidiary is consolidated under a voting or variable interest model.

On November 28, 2011, AES completed its acquisition of 100% common stock of DPL Inc. ("DPL"), the parent company of Dayton Power & Light Company ("DP&L"), a utility based in Ohio, pursuant to the terms and conditions of a definitive agreement (the "Merger Agreement") dated April 19, 2011. Upon completion of the acquisition, DPL became a wholly owned subsidiary of AES. DPL's operating results for the period November 28, 2011 through December 31, 2011 have been included in the Consolidated Statement of Operations with no comparable amounts for 2010. In accordance with the accounting guidance on business combinations, DPL's net assets acquired and liabilities assumed in the acquisition have been included in the Consolidated Balance Sheet beginning on November 28, 2011. See Note 23—*Acquisitions and Dispositions* for additional information.

CORRECTION OF AN ERROR—Certain amounts related to the dispositions of businesses presented in the Consolidated Statement of Changes in Equity in our 2010 Form 10-K were incorrectly excluded from consolidated comprehensive income for the period because the Company failed to reflect the change in foreign currency translation adjustments and derivative fair value as an offset to net income for the period in the determination of comprehensive income for four business dispositions in 2010. As a result, comprehensive income was understated by $213 million; it was previously reported as $1,283 million and has now been restated to $1,496 million for the year ended December 31, 2010. There was no impact on amounts presented on the Consolidated Balance Sheet as of December 31, 2010 or the Consolidated Statement of Operations and Statement of Cash Flows for the year ended December 31, 2010.

PRINCIPLES OF CONSOLIDATION—The Consolidated Financial Statements of the Company include the accounts of The AES Corporation, its subsidiaries and controlled affiliates. Furthermore, variable interest entities ("VIEs") in which the Company has a variable 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.

A VIE is an entity (a) that has a total equity investment at risk that is not sufficient to finance its activities without additional subordinated financial support or (b) where the group of equity holders does not have (i) the ability to make significant decisions about the entity's activities, (ii) the obligation to absorb the entity's expected losses or (iii) the right to receive the entity's expected residual returns or (c) where the voting rights of some equity holders are not proportional to their obligations to absorb expected losses, receive expected residual returns, or both, and substantially all of the entity's activities either involve or are conducted on behalf of an investor that has disproportionately few voting rights.

The determination of which party has the power to direct the activities that most significantly impact the economic performance of the VIE could require significant judgment and assumptions. That determination considers the purpose and design of the business, the risks that the business was designed to create and pass along to other entities, the activities of the business that can be directed and which party can direct them, and the expected relative impact of those activities on the economic performance of the business through its life. The businesses for which significant judgment and assumptions were required were primarily certain generation businesses who have power purchase agreements ("PPAs") to sell energy exclusively or primarily to a single counterparty for the term of those agreements. For these generation businesses, the counterparty has the power to dispatch energy and, in some instances, to make decisions regarding the sale of excess energy. As such, the counterparty has the power to direct certain activities that significantly impact the economic performance of the business primarily through the cash flows and gross margin, if any, earned by the business from the sale of energy to the counterparty and sometimes through the counterparty's absorption of fuel price risk. However, the counterparty usually does not have the power to direct any of the other activities that could significantly impact the economic performance. These other activities include: daily operation and management, maintenance, repairs and capital expenditures, plant expansion, decisions regarding the overall financing of ongoing operations and budgets and, in some instances, decisions regarding the sale of excess energy. As such, AES has the power to direct some activities of the business that significantly impact its economic performance, primarily through the cash flows and gross margin earned from capacity payments received from being available to produce energy and from the sale of energy to other entities (particularly during any period beyond the end of the power purchase agreement). For these businesses, the determination as to which set of activities most significantly impact the economic performance of the business requires significant judgment and the use of assumptions. The Company concluded that the activities directed by the counterparty were less significant than those directed by AES.

DP&L has undivided interests in seven generation facilities and numerous transmission facilities. These undivided interests in jointly-owned facilities are accounted for on a pro rata basis in our consolidated financial statements. Certain expenses, primarily fuel costs for the generating units, are allocated to the joint owners based on their energy usage. The remaining expenses, investments in fuel inventory, plant materials and operating supplies and capital additions are allocated to the joint owners in accordance with their respective ownership interests.

Deconsolidations

Thames —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 was no longer able to exercise significant influence over its operating and financial policies. In accordance with the accounting guidance on consolidation, Thames was deconsolidated on February 1, 2011 and was subsequently accounted for as a cost method investment. At the time of deconsolidation, Thames had total assets and total liabilities of $158 million and $170 million, respectively. Subsequently, the Company paid $5 million in satisfaction of a pre-existing guarantee. On January 23, 2012, Thames' request to convert to Chapter 7 liquidation was approved indicating the resolution of bankruptcy proceedings. Prior period operating results of Thames have been classified as discontinued operations. See Note 22— *Discontinued Operations and Held for Sale Businesses* for further information.

Eastern Energy—On December 30, 2011, AES Eastern Energy Limited Partnership ("AES Eastern Energy") and 13 affiliated entities and on December 31, 2011, AES New York Equity, LLC filed petitions for bankruptcy protection under Chapter 11 in the U.S. Bankruptcy Court (collectively referred to as the "New York entities"). Effective that date, the Company lost control of the business and was no longer able to exercise significant influence over its operating and financial policies. In accordance with the accounting guidance on consolidation, the New York entities were deconsolidated at December 31, 2011 and are now accounted for as a cost method investment. At the time of deconsolidation, the New York entities had total assets and total liabilities of $166 million and $289 million, respectively. A net gain of $123 million has been deferred pending the resolution of the bankruptcy proceedings. Prior period operating results of Eastern Energy have been classified as discontinued operations. See Note 22— *Discontinued Operations and Held for Sale Businesses* for further information.

Borsod—AES Borsod Kft ("Borsod"), a Hungarian subsidiary formerly operating two generation plants in Hungary, entered liquidation on November 7, 2011. Effective that date, the Company lost control of the business and was no longer able to exercise significant influence over its operating and financial policies. In accordance with the accounting guidance on consolidation, Borsod was deconsolidated and is now accounted for as a cost method investment. At the time of deconsolidation, Borsod had total assets and total liabilities of $9 million and $18 million, respectively. A net gain of $9 million has been deferred pending the resolution of liquidation proceedings. Prior period operating results of Borsod have been classified as discontinued operations. See Note 22— *Discontinued Operations and Held for Sale Businesses* for further information.

USE OF ESTIMATES—The preparation of these consolidated financial statements in conformity with accounting principles generally accepted in the United States of America ("U.S. GAAP") requires the Company to make estimates and assumptions that affect reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the consolidated financial statements, as well as the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates. Items subject to such estimates and assumptions include: the carrying amount and estimated useful lives of long-lived assets; impairment of goodwill, long-lived assets and equity method investments; valuation allowances for receivables and deferred tax assets; the recoverability of deferred regulatory assets; the estimation of deferred regulatory liabilities; the fair value of financial instruments; the fair value of assets and liabilities acquired in a business combination accounted for under the purchase method; the determination of noncontrolling interest using the hypothetical liquidation at book value ("HLBV") method for certain wind generation partnerships; pension liabilities; environmental liabilities; and potential litigation claims and settlements.

On January 1, 2011, the Company changed its estimates related to depreciation on property, plant and equipment at its Brazilian concessionary utility and generation businesses. Based on information received from regulators, the depreciation rates and salvage values for its concession assets were adjusted on a prospective basis to reflect a remuneration basis, which represents the reimbursement expected by the Company at the end of the respective concession periods. For the year ended December 31, 2011, the impact to the consolidated statement of operations was an increase in depreciation expense of $68 million and a decrease in net income attributable to The AES Corporation of $18 million, or $0.02 per share.

DISCONTINUED OPERATIONS AND RECLASSIFICATIONS—A discontinued operation is a component of the Company that either has been disposed of or is classified as held for sale. A component of the Company comprises operations and cash flows that can be clearly distinguished, operationally and for financial reporting purposes, from the rest of the Company. Prior period amounts have been retrospectively revised to reflect the businesses determined to be discontinued operations, as further discussed in Note 22—*Discontinued Operations and Held for Sale Businesses*. Cash flows at discontinued and held for sale businesses are included within the relevant categories within operating, investing and financing activities. As cash at such businesses is reported within Current assets of discontinued and held for sale businesses, the aggregate amount of cash flows is offset by the net (increase) decrease in cash of discontinued and held for sale businesses, which is presented as a separate line item in the Consolidated Statements of Cash Flows.

FAIR VALUE—Fair value, as defined in the fair value measurement accounting guidance, is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, or exit price. The Company applies the fair value measurement accounting guidance to financial assets and liabilities in determining the fair value of investments in marketable debt and equity securities, included in the consolidated balance sheet line items “Short-term investments” and “Other assets (noncurrent),” derivative assets, included in “Other current assets” and “Other assets (noncurrent)” and derivative liabilities, included in “Accrued and other liabilities (current)” and “Other long-term liabilities.” The Company applies the fair value measurement guidance to nonfinancial assets and liabilities upon the acquisition of a business or in conjunction with the measurement of an impairment loss on an asset group or goodwill under the accounting guidance for the impairment of long-lived assets or goodwill.

The fair value measurement accounting guidance requires that the Company make assumptions that market participants would use in pricing an asset or liability based on the best information available. These factors include nonperformance risk (the risk that the obligation will not be fulfilled) and credit risk of the reporting entity (for liabilities) and of the counterparty (for assets). The fair value measurement guidance prohibits the inclusion of transaction costs and any adjustments for blockage factors in determining the instruments’ fair value. The principal or most advantageous market should be considered from the perspective of the reporting entity.

Fair value, where available, is based on observable quoted market prices. Where observable prices or inputs are not available, several valuation models and techniques are applied. These models and techniques attempt to maximize the use of observable inputs and minimize the use of unobservable inputs. The process involves varying levels of management judgment, the degree of which is dependent on the price transparency of the instruments or market and the instruments’ complexity.

To increase consistency and enhance disclosure of fair value, the fair value measurement accounting guidance creates a fair value hierarchy to prioritize the inputs used to measure fair value into three categories. An asset or liability’s level within the fair value hierarchy is based on the lowest level of input significant to the fair value measurement, where Level 1 is the highest and Level 3 is the lowest. The three levels are defined as follows:

Level 1—unadjusted quoted prices in active markets accessible by the reporting entity for identical assets or liabilities. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2—pricing inputs other than quoted market prices included in Level 1 which are based on observable market data, that are directly or indirectly observable for substantially the full term of the asset or liability. These include quoted market prices for similar assets or liabilities, quoted market prices for identical or similar assets in markets that are not active, adjusted quoted market prices, inputs from observable data such as interest rate and yield curves, volatilities or default rates observable at commonly quoted intervals or inputs derived from observable market data by correlation or other means. The fair value of most over-the-counter derivatives derived from internal valuation models using market inputs and most investments in marketable debt securities qualify as Level 2.

Level 3—pricing inputs that are unobservable, or less observable, from objective sources. Unobservable inputs are only used to the extent observable inputs are not available. These inputs maintain the concept of an exit price from the perspective of a market participant and should reflect assumptions of other market participants. An entity should consider all market participant assumptions that are available without unreasonable cost and effort. These are given the lowest priority and are generally used in internally developed methodologies to generate management’s best estimate of the fair value when no observable market data is available. The fair value of the Company's reporting units determined using a discounted cash flows valuation model for goodwill impairment assessment and the fair value of the Company's long-lived asset groups determined using a discounted cash flows valuation model for the long-lived asset impairment assessments qualify as Level 3.

Any transfers between the fair value hierarchy levels are recognized at the end of the reporting period.

CASH AND CASH EQUIVALENTS—The Company considers unrestricted cash on hand, deposits in banks, certificates of deposit and short-term marketable securities, with an original or remaining maturity at the date of acquisition of three months or less, to be cash and cash equivalents. The carrying amounts of such balances approximate fair value.

RESTRICTED CASH—Restricted cash includes cash and cash equivalents which are restricted as to withdrawal or usage. The nature of restrictions includes restrictions imposed by financing agreements such as security deposits kept as collateral, debt service reserves, maintenance reserves and others, as well as restrictions imposed by long-term PPAs. On December 31, 2011, the Company reclassified approximately $130 million from restricted cash to cash and cash equivalents as it did not view certain restrictions in the financing arrangements of certain subsidiaries to be substantive in nature. Amounts at December 31, 2010 were immaterial and therefore were not reclassified for comparative presentation purposes.

INVESTMENTS IN MARKETABLE SECURITIES—Short-term investments in marketable debt and equity securities consist of securities with original or remaining maturities in excess of three months but less than one year. The Company's marketable investments are primarily unsecured debentures, certificates of deposit, government debt securities and money market funds.

Marketable debt securities that the Company has both the positive intent and ability to hold to maturity are classified as held-to-maturity and are carried at amortized cost. Other marketable securities that the Company does not intend to hold to maturity are classified as available-for-sale or trading and are carried at fair value. Available-for-sale investments are marked-to-market at the end of each reporting period, with unrealized holding gains or losses, which represent changes in the market value of the investment, reflected in accumulated other comprehensive loss ("AOCL"), a separate component of equity. In measuring the other-than-temporary impairment of debt securities, the Company identifies two components: 1) the amount representing the credit loss, which is recognized as "other non-operating expense" in the Consolidated Statements of Operations; and 2) the amount related to other factors, which is recognized in AOCL unless there is a plan to sell the security, in which case it would be recognized in earnings. The amount recognized in AOCL for held-to-maturity debt securities is then amortized in earnings over the remaining life of such securities.

Investments classified as trading are marked-to-market on a periodic basis through the Consolidated Statements of Operations. Interest and dividends on investments are reported in interest income and other income, respectively. Gains and losses on sales of investments are determined using the specific identification method.

See Note 4—*Fair Value* and the Company's fair value policy for additional discussion regarding the determination of the fair value of the Company's investments in marketable debt and equity securities.

ACCOUNTS AND NOTES RECEIVABLE AND ALLOWANCE FOR DOUBTFUL ACCOUNTS—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 collectible. Included in "Noncurrent Other Assets" are long-term financing receivables of $295 million, 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 $295 million, amounts of $232 million and $49 million, respectively, relate to our businesses in Argentina and the Dominican Republic. The remaining amount relates to our distribution businesses in Brazil.

In April 2011, the FASB issued ASU No. 2011-02, *Receivables (Topic 310), "A Creditor's Determination of Whether a Restructuring Is a Troubled Debt Restructuring"* 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. The Company adopted ASU No. 2011-2 on July 1, 2011. The adoption did not have any impact on the Company's financial position, results of operations or cash flows.

INVENTORY—Inventory primarily consists of coal, fuel oil and other raw materials used to generate power, and spare parts and supplies used to maintain power generation and distribution facilities. Inventory is carried at lower of cost or market. Cost is the sum of the purchase price and incidental expenditures and charges incurred to bring the inventory to its existing condition or location. Cost is determined under the first-in, first-out ("FIFO"), average cost or specific identification method. Generally, cost is reduced to market value if the market value of inventory has declined and it is probable that the utility of inventory, in its disposal in the ordinary course of business, will not be recovered through revenue earned from the generation of power.

LONG-LIVED ASSETS—Long-lived assets include property, plant and equipment, assets under capital leases and intangible assets subject to amortization (i.e., finite-lived intangible assets).

Property, plant and equipment

Property, plant and equipment are stated at cost, net of accumulated depreciation. The costs of renewals and improvements that extend the useful life of property, plant and equipment are capitalized.

Construction progress payments, engineering costs, insurance costs, salaries, interest and other costs directly relating to construction in progress are capitalized during the construction period, provided the completion of the project is deemed probable, or expensed at the time the Company determines that development of a particular project is no longer probable. The continued capitalization of such costs is subject to ongoing risks related to successful completion, including those related to government approvals, site identification, financing, construction permitting and contract compliance. Construction in progress balances are transferred to electric generation and distribution assets when an asset group is ready for its intended use. Government subsidies and income tax credits are recorded as a reduction to property, plant and equipment and reflected in cash flows from investing activities.

Depreciation, after consideration of salvage value and asset retirement obligations, is computed primarily using the straight-line method over the estimated useful lives of the assets, which are determined on a composite or component basis. Maintenance and repairs are charged to expense as incurred. Capital spare parts, including rotable spare parts, are included in electric generation and distribution assets. If the spare part is considered a component, it is depreciated over its useful life after the part is placed in service. If the spare part is deemed part of a composite asset, the part is depreciated over the composite useful life even when being held as a spare part.

Intangible Assets Subject to Amortization

Finite-lived intangible assets are amortized over their useful lives which range from 1 – 50 years. The Company accounts for purchased emission allowances as intangible assets and records an expense when utilized or sold. Granted emission allowances are valued at zero.

Impairment of Long-lived Assets

The Company evaluates the impairment of long-lived assets (asset group) using internal projections of undiscounted cash flows when circumstances indicate that the carrying amount of such assets may not be recoverable or the assets meet the held for sale criteria under the relevant accounting standards. Events or changes in circumstances that may necessitate a recoverability evaluation may include but are not limited to: adverse changes in the regulatory environment, unfavorable changes in power prices or fuel costs, increased competition due to additional capacity in the grid, technological advancements, declining trends in demand, an expectation that it is more likely than not that the asset will be disposed of before the end of its previously estimated useful life, etc. The carrying amount of a long-lived asset (asset group) may not be recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposal of the asset (asset group). In such cases, fair value of the long-lived asset (asset group) is determined in accordance with the fair value measurement accounting guidance. The excess of carrying amount over fair value, if any, is recognized as an impairment expense. For regulated assets, an impairment expense could be reduced by the establishment of a regulatory asset, if recovery through approved rates was probable. For non-regulated assets, impairment is recognized as an expense against earnings.

DEFERRED FINANCING COSTS—Costs incurred in connection with the issuance of long-term debt are deferred and amortized over the related financing period using the effective interest method or the straight-line method when it does not differ materially from the effective interest method. Make-whole payments in connection with early debt retirements are classified as cash flows used in investing activities.

EQUITY METHOD INVESTMENTS—Investments in entities over which the Company has the ability to exercise significant influence, but not control, are accounted for using the equity method of accounting and reported in "Investments in and advances to affiliates" on the Consolidated Balance Sheets. The Company periodically assesses the recoverability of its equity method investments. If an identified event or change in circumstances requires an impairment evaluation, management assesses the fair value based on valuation methodologies, including discounted cash flows, estimates of sale proceeds and external appraisals, as appropriate. The difference between the carrying amount of the equity method investment and its estimated fair value is recognized as impairment when the loss in value is deemed other-than-temporary and included in "Other non-operating expense" in the Consolidated Statement of Operations.

The Company discontinues the application of the equity method when an investment is reduced to zero and the Company is not otherwise committed to provide further financial support to the investee. The Company resumes the application of the equity method if the investee subsequently reports net income to the extent that the Company's share of such net income equals the share of net losses not recognized during the period in which the equity method of accounting was suspended.

GOODWILL AND INDEFINITE-LIVED INTANGIBLE ASSETS—The Company recognizes goodwill as an asset representing the future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. The Company evaluates goodwill and indefinite-lived intangible assets for impairment on an annual basis and whenever events or changes in circumstances necessitate an evaluation for impairment. The Company's annual impairment testing date is October 1.

Goodwill:

The Company evaluates goodwill impairment at the reporting unit level, which is an operating segment, as defined in the segment reporting accounting guidance, or a component (i.e., one level below an operating segment). In determining its reporting units, the Company starts with its management reporting structure. Operating segments are identified and then analyzed to identify components (usually businesses) which make up these operating segments. Two or more components are combined into a single reporting unit if they share the economic similarity criteria prescribed by the accounting guidance. Assets and liabilities are allocated to a reporting unit if the assets will be employed by or a liability relates to the operations of the reporting unit or would be considered by a market participant in determining its fair value. Goodwill resulting from an acquisition is assigned to the reporting units that are expected to benefit from the synergies of the acquisition. Generally, each AES business constitutes a reporting unit.

In December 2010, the FASB issued 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"*, which amended the accounting guidance related to goodwill. The amendment modified 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 with goodwill has a zero or negative carrying amount.

In September 2011, the FASB issued ASU No. 2011-08, *Intangibles—Goodwill and Other (Topic 350), "Testing Goodwill for Impairment"* which amended the existing guidance for goodwill impairment testing. Under the amendments in ASU No. 2011-08, an entity has the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If, after this qualitative assessment, an entity determines that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary. Also, an entity has the option to bypass the qualitative assessment for any reporting unit in any period and proceed directly to performing the first step of the two-step goodwill impairment test. The amendments did not change the existing accounting guidance on how Step 1 and Step 2 of the goodwill impairment test are performed. In addition, an entity is no longer permitted to carry forward its detailed calculation of a reporting unit's fair value from a prior year as previously permitted under the existing guidance. ASU No. 2011-08 is effective for annual and interim goodwill impairment tests performed for fiscal periods beginning on or after December 15, 2011 and early adoption is permitted. AES elected to adopt ASU No. 2011-8 early for its 2011 annual goodwill impairment evaluations performed at October 1 each year and qualitatively assessed certain of its reporting units for goodwill impairment evaluation. The adoption did not have an impact on the Company's financial position, results of operations or cash flows.

Goodwill impairment evaluation is performed in two steps. In Step 1, the carrying amount of a reporting unit is compared to its fair value and if the fair value exceeds the carrying amount, Step 2 is unnecessary. If the carrying amount exceeds the reporting unit's fair value, this could indicate potential impairment and Step 2 of the goodwill evaluation process is required to determine if goodwill is impaired and to measure the amount of impairment loss to recognize, if any. In determining the implied fair value of goodwill for impairment measurement, the accounting guidance requires measuring all assets and liabilities, including unrecognized assets and liabilities, at fair value, as would be done in a business combination. When a Step 2 analysis is required to be completed, the fair value of individual assets and liabilities is determined using valuations (which in some cases may be based in part on third party valuation reports), or other observable sources of fair value, as appropriate. If the carrying amount of goodwill exceeds its implied fair value, the excess is recognized as an impairment loss.

Most of the Company's reporting units are not publicly traded. Therefore, the Company estimates the fair value of its reporting units under the fair value measurement accounting guidance which requires making assumptions that a market participant would make in a hypothetical sale transaction at the testing date. The fair value of a reporting unit is estimated using internal budgets and forecasts, adjusted for any market participants' assumptions and discounted at the rate of return required by a market participant. The Company considers both market and income-based approaches to determine a range of fair value, but typically concludes that the value derived using an income-based approach is more representative of fair value due to the lack of direct market comparables. The Company does use market data to corroborate and determine the reasonableness of the fair value derived from the income-based discounted cash flow analysis.

Indefinite-lived Intangible Assets:

The Company's indefinite-lived intangible assets primarily include land use rights, easements, concessions and trade name. These are tested for impairment on an annual basis or whenever events or changes in circumstances necessitate an evaluation for impairment. If the carrying amount of an intangible asset exceeds its fair value, the excess is recognized as impairment expense.

ACCOUNTS PAYABLE AND OTHER ACCRUED LIABILITIES—Accounts payable consists of amounts due to trade creditors related to the Company's core business operations. The nature of these payables include amounts owed to vendors and suppliers for items such as energy purchased for resale, fuel, maintenance, inventory and other raw materials. Other accrued liabilities include items such as income taxes, regulatory liabilities, legal contingencies and employee related costs including payroll, benefits and related taxes.

REGULATORY ASSETS AND LIABILITIES—The Company accounts for certain of its regulated operations in accordance with the accounting standards on regulated operations. As a result, AES records assets and liabilities that result from the regulated ratemaking process that are not recognized under GAAP for non-regulated entities. Regulatory assets generally represent incurred costs that have been deferred due to the probability of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers.

Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes, recent rate orders applicable to other regulated entities and the status of any pending or potential deregulation legislation. If future recovery of costs previously deferred ceases to be probable, the related regulatory assets are written off and recognized in continuing operations.

PENSION AND OTHER POSTRETIREMENT PLANS—In accordance with the accounting guidance on defined benefit pension and other postretirement plans, the Company recognizes in its Consolidated Balance Sheets an asset or liability reflecting the funded status of pension and other postretirement plans with current year changes in the funded status recognized in AOCL, except for those plans at certain of the Company's regulated utilities that can recover portions of their pension and postretirement obligations through future rates. All plan assets are recorded at fair value. AES follows the measurement date provisions of the accounting guidance, which require a year-end measurement date of plan assets and obligations for all defined benefit plans.

INCOME TAXES—Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of the existing assets and liabilities, and their respective income tax bases. The Company establishes a valuation allowance when it is more likely than not that all or a portion of a deferred tax asset will not be realized. The Company's tax positions are evaluated under a more-likely-than-not recognition threshold and measurement analysis before they are recognized for financial statement reporting.

Uncertain tax positions have been classified as noncurrent income tax liabilities unless expected to be paid within one year. The Company's policy for interest and penalties related to income tax exposures is to recognize interest and penalties as a component of the provision for income taxes in the Consolidated Statements of Operations.

ASSET RETIREMENT OBLIGATIONS—In accordance with the accounting standards for asset retirement obligations, the Company records the fair value of the liability for a legal obligation to retire an asset in the period in which the obligation is incurred. When a new liability is recognized, the Company capitalizes the costs of the liability by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the obligation, the Company eliminates the liability and, based on the actual cost to retire, may incur a gain or loss.

NONCONTROLLING INTERESTS—Noncontrolling interests are classified as a separate component of equity in the Consolidated Balance Sheets and Consolidated Statements of Changes in Equity. Additionally, net income and comprehensive income attributable to noncontrolling interests are reflected separately from consolidated net income and comprehensive income in the Consolidated Statements of Operations and Consolidated Statements of Changes in Equity. Any change in ownership of a subsidiary while the controlling financial interest is retained is accounted for as an equity transaction between the controlling and noncontrolling interests. Losses continue to be attributed to the noncontrolling interests, even when the noncontrolling interests' basis has been reduced to zero.

Although in general, the noncontrolling ownership interest in earnings is calculated based on ownership percentage, certain of the Company's wind businesses use the HLBV method in consolidation. HLBV uses a balance sheet approach, which measures the Company's equity in income or loss by calculating the change in the amount of net worth the partners are legally able to claim based on a hypothetical liquidation of the entity at the beginning of a reporting period compared to the end of that period. This method is used in Wind Generation partnerships which contain agreements designating different allocations of value among investors, where the allocations change in form or percentage over the life of the partnership.

GUARANTOR ACCOUNTING—In accordance with the accounting standards on guarantees, at the inception of a guarantee, the Company records the fair value of a guarantee as a liability, with the offset dependent on the circumstances under which the guarantee was issued.

TRANSFER OF FINANCIAL ASSETS—Effective January 1, 2010, the Company prospectively adopted the new accounting guidance on transfers of financial assets, which among other things: removes the concept of a qualifying special purpose entity; introduces the concept of participating interests and specifies that in order to qualify for sale accounting a partial transfer of a financial asset or a group of financial assets should meet the definition of a participating interest; clarifies that an entity should consider all arrangements made contemporaneously with or in contemplation of a transfer; and, requires enhanced disclosures to provide financial statement users with greater transparency about transfers of financial assets and a transferor's continuing involvement with transfers of financial assets accounted for as sales. Upon adoption on January 1, 2010, the Company recognized $40 million as accounts receivable and as an associated secured borrowing on its Consolidated Balance Sheet; both have since increased to $50 million as of December 31, 2011, as additional interests in receivables have been sold. While securitizing these accounts receivable through IPL Funding, a special purpose entity, IPL, the Company's integrated utility in Indianapolis, had previously recognized the transaction as a sale, but had not recognized the accounts receivable and secured borrowing on its balance sheet. Under the facility, interests in these accounts receivable are sold, on a revolving basis, to unrelated parties (the Purchasers) up to the lesser of $50 million or an amount determinable under the facility agreement. The Purchasers assume the risk of collection on the interest sold without recourse to IPL, which retains the servicing responsibilities for the interest sold. While no direct recourse to IPL exists, IPL risks loss in the event collections are not sufficient to allow for full recovery of the retained interests. No servicing asset or liability is recorded since the servicing fee paid to IPL approximates a market rate. Under the new accounting guidance, the retained interest in these securitized accounts receivable does not meet the definition of a participating interest, thereby requiring the Company to recognize on its Consolidated Balance Sheet the portion transferred and the proceeds received as accounts receivable and a secured borrowing, respectively.

FOREIGN CURRENCY TRANSLATION—A business' functional currency is the currency of the primary economic environment in which the business operates and is generally the currency in which the business generates and expends cash. Subsidiaries and affiliates whose functional currency is a currency other than the U.S. Dollar translate their assets and liabilities into U.S. Dollars at the current exchange rates in effect at the end of the fiscal period. The revenue and expense accounts of such subsidiaries and affiliates are translated into U.S. Dollars at the average exchange rates that prevailed during the period. Translation adjustments are included in AOCL. Gains and losses on intercompany foreign currency transactions that are long-term in nature and which the Company does not intend to settle in the foreseeable future, are also recognized in AOCL. Gains and losses that arise from exchange rate fluctuations on transactions denominated in a currency other than the functional currency are included in determining net income.

REVENUE RECOGNITION—Revenue from Utilities is classified as regulated in the Consolidated Statements of Operations. Revenue from the sale of energy is recognized in the period during which the sale occurs. The calculation of revenue earned but not yet billed is based on the number of days not billed in the month, the estimated amount of energy delivered during those days and the estimated average price per customer class for that month. Differences between actual and estimated unbilled revenue are usually immaterial. The Company has businesses where it makes sales and purchases of power to and from Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs"). In those instances, the Company accounts for these transactions on a net hourly basis because the transactions are settled on a net hourly basis. Revenue from Generation businesses is classified as non-regulated and is recognized based upon output delivered and capacity provided, at rates as specified under contract terms or prevailing market rates. Certain of the Company PPAs meet the definition of an operating lease or contain similar arrangements. Typically, minimum lease payments from such PPAs are recognized as revenue on a straight line basis over the lease term whereas contingent rentals are recognized when earned. Revenue is recorded net of any taxes assessed on and collected from customers, which are remitted to the governmental authorities.

In October 2009, the FASB issued ASU No. 2009-13, *Revenue Recognition (Topic 605), "Multiple-Deliverable Revenue Arrangements"*, which amended the accounting guidance related to revenue recognition.

The amended guidance provides primarily 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. AES adopted the standard 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. The adoption of ASU No. 2009-13 did not have a material impact on the financial position and results of operations of AES and is not expected to have a material impact in future periods.

SHARE-BASED COMPENSATION—The Company grants share-based compensation in the form of stock options and restricted stock units. The Company accounts for stock-based compensation plans under the accounting guidance on stock-based compensation, which requires entities to recognize compensation costs relating to share-based payments in their financial statements. That cost is measured on the grant date based on the fair value of the equity or liability instrument issued and is expensed on a straight-line basis over the requisite service period, net of estimated forfeitures. Currently, the Company uses a Black-Scholes option pricing model to estimate the fair value of stock options granted to its employees.

GENERAL AND ADMINISTRATIVE EXPENSES—General and administrative expenses include corporate and other expenses related to corporate staff functions and initiatives, primarily executive management, finance, legal, human resources and information systems, which are not directly allocable to our business segments. Additionally, all costs associated with business development efforts are classified as general and administrative expenses.

DERIVATIVES AND HEDGING ACTIVITIES—Derivatives primarily consist of interest rate swaps, cross currency swaps, foreign currency instruments, and commodity and embedded derivatives. The Company enters into various derivative transactions in order to hedge its exposure to certain market risks. AES primarily uses derivative instruments to manage its interest rate, foreign currency and commodity exposures. The Company does not enter into derivative transactions for trading purposes.

Under the accounting standards for derivatives and hedging, the Company recognizes all contracts that meet the definition of a derivative, except those designated as normal purchase or normal sale at inception, as either assets or liabilities in the Consolidated Balance Sheets and measures those instruments at fair value. Changes in the fair value of derivatives are recognized in earnings unless specific hedge criteria are met. Gains and losses related to derivative instruments that qualify as hedges are recognized in the same category as generated by the underlying asset or liability. Gains or losses on derivatives that do not qualify for hedge accounting are recognized as interest expense for interest rate and cross currency derivatives, foreign currency transaction gains or losses for foreign currency derivatives, and non-regulated revenue or non-regulated cost of sales for commodity derivatives.

The accounting standards for derivatives and hedging enable companies to designate qualifying derivatives as hedging instruments based on the exposure being hedged. These hedge designations include fair value hedges and cash flow hedges. Changes in the fair value of a derivative that is highly effective, designated and qualifies as a fair value hedge are recognized in earnings as offsets to the changes in fair value of the exposure being hedged. The Company has no fair value hedges at this time. Changes in the fair value of a derivative that is highly effective, designated and qualifies as a cash flow hedge are deferred in AOCL and are recognized into earnings as the hedged transactions affect earnings. Any ineffectiveness is recognized in earnings immediately.

The ineffective portion is recognized as interest expense for interest rate and cross currency hedges, foreign currency transaction gains or losses for foreign currency hedges, and non-regulated revenue or non-regulated cost of sales for commodity hedges. For all hedge contracts, the Company maintains formal documentation of the hedge and effectiveness testing in accordance with the accounting standards for derivatives and hedging. If AES determines that the derivative is not highly effective as a hedge, hedge accounting will be discontinued prospectively.

For cash flow hedges of forecasted transactions, AES estimates the future cash flows of the forecasted transactions and evaluates the probability of the occurrence and timing of such transactions. Changes in conditions or the occurrence of unforeseen events could require discontinuance of hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from AOCL into earnings.

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.

See Note 4—*Fair Value* and the Company's fair value policy for additional discussion regarding the determination of the fair value of the Company's derivative assets and liabilities.

Accounting Pronouncements Issued But Not Yet Effective

The following accounting standards have been issued, but as of December 31, 2011 are not yet effective for and have not been adopted by AES.

ASU No. 2011-04, Fair Value Measurements (Topic 820), "Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs"

In May 2011, the FASB issued ASU No. 2011-04, which among other requirements, prohibits the use of the block discount factor for all fair value level hierarchies; permits an entity to measure the fair value of its financial instruments on a net basis when the related market risks are managed on a net basis; states the highest and best use concept is no longer relevant in the measurement of financial assets and liabilities; clarifies that a reporting entity should disclose quantitative information about the unobservable inputs used in Level 3 measurements and that the application of premiums and discounts is related to the unit of account for the asset or liability being measured at fair value; and requires expanded disclosures to describe the valuation process used for Level 3 measurements and the sensitivity of Level 3 measurements to changes in unobservable inputs. In addition, entities are required to disclose the hierarchy level for items which are not measured at fair value in the statement of financial position, but for which fair value is required to be disclosed. ASU No. 2011-04 is effective for the first interim or annual period beginning on or after December 15, 2011, or January 1, 2012 for AES. The adoption is not expected to have a material impact on the Company's financial position, results of operations or cash flows.

ASU No. 2011-10, Property, Plant, and Equipment (Topic 360), "Derecognition of in Substance Real Estate—a Scope Clarification"

In December 2011, the FASB issued ASU No. 2011-10, which clarifies that when a parent (reporting entity) ceases to have a controlling financial interest (as described in Subtopic 810-10) in a subsidiary that is in substance real estate as a result of default on the subsidiary's nonrecourse debt, the reporting entity should apply the guidance in Subtopic 360-20 to determine whether it should derecognize the in substance real estate. Generally, a reporting entity would not satisfy the requirements to derecognize the in substance real estate before the legal transfer of the real estate to the lender and the extinguishment of the related nonrecourse indebtedness. That is, even if the reporting entity ceases to have a controlling financial interest under Subtopic 810-10, the reporting entity would continue to include the real estate, debt, and the results of the subsidiary's operations in its consolidated financial statements until legal title to the real estate is transferred to legally satisfy the debt. ASU No. 2011-10 should be applied on a prospective basis to deconsolidation events occurring after the effective date. Prior periods should not be adjusted even if the reporting entity has continuing involvement with previously derecognized in substance real estate entities. ASU No. 2011-10 is effective for fiscal years, and interim periods within those years, beginning on or after June 15, 2012. Early adoption is permitted. The adoption of ASU No. 2011-10 is not expected to have a material impact on the Company's financial position and results of operations.

2. INVENTORY

As of December 31, 2011, 81% of the Company's inventory was valued using average cost, 17% was determined using the FIFO method and the remaining inventory was valued using the specific identification method. The following table summarizes our inventory balances as of December 31, 2011 and 2010:

	December 31,	
	2011	2010
	(in millions)	
Coal, fuel oil and other raw materials	$444	$272
Spare parts and supplies	345	280
Total	$789	$552

3. PROPERTY, PLANT & EQUIPMENT

The following table summarizes the components of the electric generation and distribution assets and other property, plant and equipment with their estimated useful lives:

	Estimated Useful Life	December 31,	
		2011	2010
		(in millions)	
Electric generation and distribution facilities	5 - 69 yrs.	$27,627	$23,133
Other buildings	3 - 50 yrs.	2,927	2,085
Furniture, fixtures and equipment	3 - 31 yrs.	481	484
Other	1 - 46 yrs.	913	812
Total electric generation and distribution assets and other		31,948	26,514
Accumulated depreciation		(9,145)	(8,643)
Net electric generation and distribution assets and other(1)		$22,803	$17,871

(1) Net electric generation and distribution assets and other related to our businesses included in discontinued operations or held for sale of $622 million and $1.2 billion as of December 31, 2011 and 2010, respectively, were excluded from the table above and were included in the noncurrent assets of discontinued and held for sale businesses.

The amounts in the table above are stated net of impairment losses recognized as further discussed in Note 20—*Impairment Expense.*

The following table summarizes interest capitalized during development and construction on qualifying assets for the years ended December 31, 2011, 2010 and 2009:

	2011	2010	2009
		(in millions)	
Interest capitalized during development and construction	$176	$188	$183

Government subsidies and recoveries of liquidated damages from construction delays are reflected as a reduction in the related projects' construction costs. During 2011, the Company recovered liquidated damages of €139 million ($180 million) from the EPC contractor at Maritza, which were used to reduce the carrying amount of related plant and equipment. Approximately $13.5 billion of property, plant and equipment, net of accumulated depreciation, was mortgaged, pledged or subject to liens as of December 31, 2011.

Depreciation expense, including the amortization of assets recorded under capital leases, was $1.2 billion, $1.1 billion and $891 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Net electric generation and distribution assets and other include unamortized internal use software costs of $157 million and $164 million as of December 31, 2011 and 2010, respectively. Amortization expense associated with software costs was $46 million, $50 million and $46 million for the years ended December 31, 2011, 2010 and 2009.

The following table summarizes regulated and non-regulated generation and distribution property, plant and equipment and accumulated depreciation as of December 31, 2011 and 2010:

	December 31,	
	2011	2010
	(in millions)	
Regulated assets	$14,468	$12,006
Regulated accumulated depreciation	(5,029)	(4,961)
Regulated generation, distribution assets, and other, net	9,439	7,045
Non-regulated assets	17,480	14,508
Non-regulated accumulated depreciation	(4,116)	(3,682)
Non-regulated generation, distribution assets, and other, net	13,364	10,826
Net electric generation and distribution assets, and other	$22,803	$17,871

The following table summarizes the amounts recognized, which were related to asset retirement obligations, for the years ended December 31, 2011 and 2010:

	2011	2010
	(in millions)	
Balance at January 1	$ 88	$ 60
Additional liabilities incurred	1	22
Assumed in business combination	24	—
Accretion expense	6	5
Change in estimated cash flows	(1)	1
Translation adjustments	(1)	—
Balance at December 31	$117	$ 88

The Company's asset retirement obligations covered by the relevant guidance primarily include active ash landfills, water treatment basins and the removal or dismantlement of certain plant and equipment. The fair value of legally restricted assets for purposes of settling asset retirement obligations was $1 million at December 31, 2011. There were no legally restricted assets at December 31, 2010.

Ownership of Coal-Fired Facilities

DP&L has undivided ownership interests in seven coal-fired generation facilities jointly owned with other utilities. As of December 31, 2011, DP&L had $48 million of construction work in process at such facilities. DP&L's share of the operating costs of such facilities is included in Cost of Sales in the Consolidated Statement of Operations and its share of investment in the facilities is included in Property, Plant and Equipment in the Consolidated Balance Sheet. DP&L's undivided ownership interest in such facilities at December 31, 2011 is as follows:

	DP&L Share		DP&L Investment		
	Ownership	Production Capacity (MW)	Gross Plant In Service	Accumulated Depreciation	Construction Work In Process
				($ in millions)	
Production Units:					
Beckjord Unit 6	50%	210	$—	$—	$—
Conesville Unit 4	17%	129	—	—	2
East Bend Station	31%	186	—	—	2
Killen Station	67%	402	331	—	4
Miami Fort Units 7 and 8	36%	368	239	1	2
Stuart Station	35%	820	181	1	14
Zimmer Station	28%	365	161	2	24
Transmission	various		34	—	—
Total		2,480	$946	$ 4	$ 48

4. FAIR VALUE

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 differently based upon the type of loan. In general, the carrying amount of variable rate debt is a close approximation of its fair value. For fixed rate loans, the fair value is estimated using quoted market prices or discounted cash flow analyses. See Note 11—*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 December 31, 2011 and 2010:

	December 31,			
	2011		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Assets				
Marketable securities	$ 1,356	$ 1,356	$ 1,760	$ 1,760
Derivatives	120	120	119	119
Total assets	$ 1,476	$ 1,476	$ 1,879	$ 1,879
Liabilities				
Debt	$22,573	$ 23,065	$18,788	$19,374
Derivatives	690	690	358	358
Total liabilities	$23,263	$23,755	$19,146	$19,732

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 estimated under 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, or LIBOR, a benchmark interest rate widely used by banks in the interbank lending market) or Selic (overnight borrowing rate) rates in Brazil. 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 5—*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 over-the-counter financial and physical derivative instruments. The 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 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, with the exception of those classified as Level 1, 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 with the same tenor as the derivative instrument being valued are generally obtained from published sources, with these forward rates being assessed quarterly at a portfolio-level for reasonableness versus comparable, published information provided from another source. 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, with the exception of those classified as Level 1, 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.

The Company's methodology to fair value its derivatives is to start with any observable inputs, however, 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 from and to Level 2 and are determined as of the end of the reporting period.

The only Level 1 derivative instruments as of December 31, 2011 are exchange-traded commodity futures for which the pricing is observable in active markets, and as such these are not expected to transfer to other levels.

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.

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, Reuters, and Platt's). To determine fair value, where market data is not readily available, management uses comparable market sources and empirical evidence to develop its own estimates of market assumptions.

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 fair value derived from quoted market data to mark the investments 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 December 31, 2011 and 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 December 31, 2011
	(in millions)			
Assets				
Available-for-sale securities	$ 1	$1,339	$—	$1,340
Trading securities	12	—	—	12
Derivatives	2	52	66	120
Total assets	$ 15	$1,391	$ 66	$1,472
Liabilities				
Derivatives	$—	$ 476	$214	$ 690
Total liabilities	$—	$ 476	$214	$ 690

	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	$1,700	$ 42	$1,750
Trading securities	10	—	—	10
Derivatives	—	58	61	119
Total assets	$ 18	$1,758	$103	$1,879
Liabilities				
Derivatives	$—	$ 346	$ 12	$ 358
Total liabilities	$—	$ 346	$ 12	$ 358

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 years ended December 31, 2011 and 2010 (presented net by type of derivative):

	Year Ended December 31, 2011				
	Interest Rate	Cross Currency	Foreign Currency	Commodity & Other	Total
			(in millions)		
Balance at beginning of period	$ (1)	$ 10	$ 22	$ 18	$ 49
Total gains (losses) (realized and unrealized):					
Included in earnings[1]	—	(4)	32	(71)	(43)
Included in other comprehensive income	(13)	(37)	—	—	(50)
Included in regulatory assets	—	—	—	8	8
Settlements	—	13	(3)	(8)	2
Transfers of assets (liabilities) into Level 3[2]	(117)	—	—	—	(117)
Transfers of (assets) liabilities out of Level 3[2]	3	—	—	—	3
Balance at end of period	$(128)	$ (18)	$ 51	$ (53)	$(148)
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)	$ 29	$ (71)	$ (44)

	Year Ended December 31, 2010				
	Interest Rate	Cross Currency	Foreign Currency	Commodity & Other	Total
			(in millions)		
Balance at beginning of period	$ (12)	$ (12)	$—	$ 24	$—
Total gains (losses) (realized and unrealized):					
Included in earnings[1]	1	4	25	21	51
Included in other comprehensive income	(12)	13	—	—	1
Included in regulatory assets	(3)	—	—	1	(2)
Settlements	7	5	(1)	(28)	(17)
Transfers of assets (liabilities) into Level 3[2]	—	—	(2)	—	(2)
Transfers of (assets) liabilities out of Level 3[2]	18	—	—	—	18
Balance at end of period	$ (1)	$ 10	$ 22	$ 18	$ 49
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	$—	$ 7	$ 24	$ 9	$ 40

(1) 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 6—*Derivative Instruments and Hedging Activities* for further information regarding the classification of gains and losses included in earnings in the Consolidated Statements of Operations.

(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 only Level 1 derivative instruments as of December 31, 2011 are exchange-traded commodity futures for which the pricing is observable in active markets, and as such these are not expected to transfer to other levels. 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.

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 years ended December 31, 2011 and 2010:

	Year Ended December 31,	
	2011	2010
	(in millions)	
Balance at beginning of period[1]	$ 42	$ 42
Settlements	(42)	—
Balance at end of period	$—	$ 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 variable rate demand notes which have failed remarketing and for which there are no longer adequate observable inputs to measure the fair value.

Nonrecurring Measurements:

For purposes of impairment evaluation, the Company measured the fair value of long-lived assets and equity method investments under the fair value measurement accounting guidance. To measure the amount of impairment, the Company compares the fair value of assets and liabilities at the evaluation date to the carrying amount at the end of the month prior to the evaluation date. The following table summarizes major categories of assets and liabilities measured at fair value on a nonrecurring basis during the period and their level within the fair value hierarchy:

	Year Ended December 31, 2011				
	Carrying Amount	Fair Value			Gross (Gain) Loss
		Level 1	Level 2	Level 3	
	(in millions)				
Long-lived assets held and used:					
Wind turbines and deposits	$ 161	$—	$ 45	$—	$ 116
Tisza II	94	—	—	42	52
Kelanitissa	66	—	—	24	42
Bohemia	14	—	5	—	9
Discontinued operations and businesses held for sale:					
Edelap, Edes and Central Dique	350	—	4	—	346
Carbon reduction projects	49	—	—	—	40[1]
Wind projects	22	—	—	—	22
Borsod[2]	(9)	—	—	—	—
Eastern Energy[2]	(123)	—	—	—	—
Thames[2]	(7)	—	—	—	—
Brazil Telecom businesses	142	—	893	—	(751)
Equity method affiliates:					
Yangcheng	100	—	—	26	74
Goodwill:					
Chigen	17	—	—	—	17

	Year Ended December 31, 2010				
	Carrying Amount	Fair Value Level 1	Fair Value Level 2	Fair Value Level 3	Gross (Gain) Loss
			(in millions)		
Long-lived assets held and used:					
Southland (Huntington Beach)	$288	$—	$—	$ 88	$ 200
Tisza II	160	—	—	75	85
Deepwater	83	—	—	4	79
Discontinued operations and businesses held for sale:					
Eastern Energy	827	—	—	—	827
Barka	20	—	124	—	(104)
Ras Laffan	120	—	226	—	(106)
Goodwill:					
Deepwater	18	—	—	—	18
Other	3	—	—	—	3

(1) The carrying amounts and fair value of the asset groups also include other assets and liabilities; however, impairment expense recognized was limited to the carrying amounts of long-lived assets.

(2) The businesses, currently in liquidation/bankruptcy proceedings, had negative carrying amounts at the measurement date. Related gains on deconsolidation have been deferred pending the resolution of bankruptcy protection/liquidation proceedings.

Long-lived Assets Held and Used

Wind Turbines and Deposits—During the third quarter of 2011, the Company determined that certain wind turbines and deposits held by our Wind Generation business were impaired. The long-lived assets with a carrying amount of $161 million were written down to their estimated fair value of $45 million under the market approach. This resulted in the recognition of asset impairment expense of $116 million for the year ended December 31, 2011.

Tisza II—In the fourth quarter of 2011, the Company determined there were impairment indicators for the long-lived assets at Tisza II, our gas-fired generation plant in Hungary. The asset group had a carrying amount of $94 million and was written down to its estimated fair value of $42 million resulting in the recognition of asset impairment expense of $52 million.

Kelanitissa—In 2011, the Company determined the long-lived assets at Kelanitissa, our diesel-fired plant in Sri Lanka, were impaired. The long-lived assets with a carrying amount of $66 million were written down to their estimated fair value of $24 million based on a discounted cash flow analysis. This resulted in the recognition of asset impairment expense of $42 million for the year ended December 31, 2011.

For further discussion of these impairments, see Note 20—*Impairment Expense.*

Discontinued Operations and Held for Sale Businesses

Edelap, Edes and Central Dique—During the fourth quarter of 2011, the Company sold its ownership interest in two distribution companies Empresa Distribuidora La Plata S.A. ("Edelap"), Empresa Distribuidora de Energia Sur S.A. ("Edes") and a 68 MW generation plant, Central Dique S.A. (collectively, "Argentina distribution businesses") in Argentina. These businesses had a carrying amount of $350 million, which was written down to the net sale price of $4 million resulting in a loss on disposal of $346 million.

Carbon Reduction Projects—In 2011, the Company determined that it would sell its interest in carbon reduction projects, our emission reduction credit projects in Asia and Latin America. The long-lived asset groups with an aggregate carrying amount of $49 million were written down to their estimated fair value of $5 million based on discounted cash flows analysis.

Wind Projects—In the fourth quarter of 2011, the Company determined that it would not pursue certain wind development projects in Poland and the U.K. The operating results of these projects have been presented as discontinued operations as they met the applicable criteria for reporting discontinued operations. The intangible assets, primarily project development rights, with an aggregate carrying amount of $22 million were fully written off based on discounted cash flows analysis.

Eastern Energy, Thames and Borsod—In 2011, these businesses filed for bankruptcy protection and/or liquidation. As of December 31, 2011, they were accounted for as cost method investments with the prior period operating results presented as discontinued operations. Gains resulting from their deconsolidation have been deferred pending the finalization of liquidation/bankruptcy proceedings. See Note 1—*General and Summary of Significant Accounting Policies, Principles of Consolidation* for further information.

Brazil Telecom Businesses—In the fourth quarter of 2011, the Company completed the sale of its ownership interest in two telecommunication businesses in Brazil. The businesses had a carrying amount of $142 million and were sold for $893 million (net of selling costs) resulting in a gain of $751 million before income tax and noncontrolling interests.

For further discussion, see Note 22—*Discontinued Operations and Held for Sale Businesses*.

Equity Method Affiliate

Yangcheng International Power Generating Co. Ltd. ("Yangcheng")—During the third quarter of 2011, the Company determined that the carrying amount of Yangcheng, a 2,100 MW venture in China in which AES owns a 25% interest, had incurred an other-than-temporary impairment. Yangcheng's carrying amount of $100 million was written down to its estimated fair value of $26 million determined under the income approach, resulting in the recognition of other non-operating expense of $74 million for the year ended December 31, 2011. See Note 7—*Investments In and Advances to Affiliates* and Note 8—*Other Non-Operating Expense* for further information.

Goodwill

During the third quarter of 2011, the Company determined there were impairment indicators for the goodwill at Chigen, our holding company in China that holds AES' interests in Chinese ventures, including its investment in Yangcheng. Goodwill of $17 million was written down to its implied fair value of zero during an interim impairment evaluation, resulting in the recognition of goodwill impairment of $17 million for the year ended December 31, 2011.

For further discussion, see Note 9—*Goodwill and Other Intangible Assets.*

Long-lived Assets Held and Used

Tisza II and Southland (Huntington Beach). During the third quarter of 2010, the Company determined there were impairment indicators for the long-lived assets at Tisza II, our gas-fired generation plant in Hungary, and Southland, our gas-fired generation plants in California. These long-lived assets had carrying amounts of $160 million and $288 million, respectively, and were written down to their fair value of $75 million and $88 million, respectively. These resulted in the recognition of asset impairment expense of $85 million and $200 million, respectively, during the year ended December 31, 2010.

Deepwater. In the fourth quarter of 2010, the Company determined there were impairment indicators for the long-lived assets at Deepwater, our pet-coke-fired generation facility in Texas. These long-lived assets had a carrying amount of $83 million and were written down to their fair value of $4 million. This resulted in the recognition of asset impairment expense of $79 million.

For further discussion of these impairments, see Note 20—*Impairment Expense.*

Discontinued Operations and Held for Sale Businesses

In the fourth quarter of 2010, the Company determined there were impairment indicators for the long-lived assets at Eastern Energy. These long-lived assets had a carrying amount of $827 million and were considered fully impaired. As a result, an impairment loss of $827 million was recognized, which is included in Income from operations of discontinued businesses in the Consolidated Statement of Operations.

The Company determined the fair value of nonfinancial assets and liabilities of our held for sale businesses during the year ended December 31, 2010. These businesses included Barka in Oman, Ras Laffan in Qatar, and Eastern Energy, our coal-fired generation plants in New York.

For further discussion, see Note 22—*Discontinued Operations and Held for Sale Businesses*.

Goodwill

During the third quarter of 2010, the Company determined there were impairment indicators for the long-lived assets and goodwill at Deepwater, our pet coke-fired generation plant in Texas. Goodwill with an aggregate carrying amount of $18 million was written down to its implied fair value of zero, resulting in the recognition of goodwill impairment of $18 million for the year ended December 31, 2010.

For further discussion, see Note 9—*Goodwill and Other Intangible Assets.*

5. INVESTMENTS IN MARKETABLE SECURITIES

The following table sets forth the Company's investments in marketable debt and equity securities classified as trading and available-for-sale as of December 31, 2011 and 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 securities.

	December 31,							
	2011				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]	$—	$ 665	$—	$ 665	$—	$ 719	$—	$ 719
Certificates of deposit[2]	—	576	—	576	—	873	—	873
Government debt securities	—	31	—	31	—	47	—	47
Other	—	—	—	—	—	—	42	42
Subtotal	—	1,272	—	1,272	—	1,639	42	1,681
Equity securities:								
Mutual funds	—	67	—	67	1	61	—	62
Common stock	1	—	—	1	7	—	—	7
Subtotal	1	67	—	68	8	61	—	69
Total available-for-sale	1	1,339	—	1,340	8	1,700	42	1,750
TRADING:								
Equity securities:								
Mutual funds	12	—	—	12	10	—	—	10
Total trading	12	—	—	12	10	—	—	10
TOTAL	$ 13	$1,339	$—	$1,352	$ 18	$1,700	$ 42	$1,760
Held-to-maturity securities				4				—
Total marketable securities				$1,356				$1,760

(1) Amortized cost approximated fair value at December 31, 2011 and 2010, with the exception of certain common stock investments with a cost basis of $4 million and $6 million carried at their fair value of $1 million and $7 million at December 31, 2011 and 2010, respectively. In 2011, the Company recognized an other than temporary impairment of $3 million in net income on these investments.

(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 and meet the definition of a security under the relevant guidance and are therefore classified as available-for-sale securities.

As of December 31, 2011, all available-for-sale debt securities had stated maturities less than one year. As of December 31, 2010, all available-for-sale debt securities had stated maturities less than one year with the exception of $42 million of securities, primarily variable rate demand notes, held by IPL, a subsidiary of the Company in Indiana. These securities, classified as other debt securities in the table above, had stated maturities of greater than ten years, and were called at par during 2011.

The following table summarizes the pre-tax gains and losses related to available-for-sale securities for the years ended December 31, 2011, 2010 and 2009. As noted above, the Company recognized an other than temporary impairment of $3 million in 2011. There was no other-than-temporary impairment of marketable securities recognized in earnings or other comprehensive income for the years ended December 31, 2010 or 2009.

	2011	2010	2009
		(in millions)	
Gains included in earnings that relate to trading securities held at the reporting date	$ 1	$ —	$ 1
Unrealized gains (losses) on available-for-sale securities included in other comprehensive income	2	2	10
Gains reclassified out of other comprehensive income into earnings	—	—	2
Proceeds from sales of available-for-sale securities	6,119	5,852	4,440
Gross realized gains on sales	3	2	3

6. 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 generally utilize variable rate debt financing for construction projects and operations, resulting in an exposure to interest rate risk. Interest rate swap, lock, 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 2043, and are typically designated as cash flow hedges. The following table sets forth, by underlying type of interest rate index, the Company's current outstanding 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 December 31, 2011 regardless of whether the derivative instruments are in qualifying cash flow hedging relationships:

	December 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)	3,628	$3,628	4,697	$4,697	11	67%
EURIBOR (Euro)	673	872	673	872	11	63%
LIBOR (British Pound Sterling)	58	90	82	128	13	87%

(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 December 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 forecasted issuances of debt and variable-rate debt tied to other indices where the Company has no interest rate derivatives.

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 amount under its cross currency derivative instruments as of December 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 amount as of December 31, 2011:

	December 31, 2011			
Cross Currency Swaps	**Notional**	**Notional Translated to USD**	**Weighted Average Remaining Term[1]**	**% of Debt Currently Hedged by Index[2]**
	(in millions)		(in years)	
Chilean Unidad de Fomento (CLF)	6	$240	14	85%

(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 countries 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 2015. 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 December 31, 2011 regardless of whether the derivative instruments are in qualifying hedging relationships:

	December 31, 2011			
Foreign Currency Options	**Notional[1]**	**Notional Translated to USD[1]**	**Probability Adjusted Notional[2]**	**Weighted Average Remaining Term[3]**
		(in millions)		(in years)
Euro (EUR)	38	$54	$52	<1
Brazilian Real (BRL)	86	52	49	<1
British Pound (GBP)	27	44	35	<1
Philippine Peso (PHP)	414	10	7	<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	December 31, 2011 Notional	Notional Translated to USD	Weighted Average Remaining Term[(1)]
	(in millions)		(in years)
Euro (EUR)	113	$154	2
Chilean Peso (CLP)	72,169	145	<1
British Pound (GBP)	11	16	<1
Argentine Peso (ARS)	61	13	<1
Colombian Peso (COP)	23,993	13	<1
Hungarian Forint (HUF)	1,236	5	<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 December 31, 2011:

Embedded Foreign Currency Derivatives	December 31, 2011 Notional	Notional Translated to USD	Weighted Average Remaining Term[(1)]
	(in millions)		(in years)
Philippine Peso (PHP)	13,692	$312	2
Argentine Peso (ARS)	938	218	11
Kazakhstani Tenge (KZT)	29,635	200	8
Euro (EUR)	3	3	9

(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 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 agreements 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 derivative and embedded derivative instruments as of December 31, 2011:

	December 31, 2011	
Commodity Derivatives	**Notional**	**Weighted Average Remaining Term**(1)
	(in millions)	**(in years)**
Natural gas (MMBtu)	31	12
Petcoke (Metric tons)	13	12
Aluminum (MWh)	16(2)	8
Heating Oil (Gallons)	3	1
Coal (Metric tons)	4	3

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

(2) Sonel's PPA with its primary offtaker, an aluminum smelter, contains an embedded derivative which reflects the linkage of our energy contract pricing, in part, to the price of aluminum as quoted on the London Metals Exchange, a global metals exchange (as required by contract). The linkage between the contract price of power based on forecasted forward aluminum price curves and the Cameroon market price for power provides for economic alignment between Sonel's financial results under the PPA and the offtaker's financial performance. However, to the extent there are fluctuations in the price of aluminum as compared to the market price for power under our PPA, we may be exposed to significant swings in earnings through mark-to-market adjustments of the embedded derivative as the market price for aluminum has proven to be volatile.

Accounting and Reporting

The following table sets forth the Company's derivative instruments as of December 31, 2011 and 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 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 and long-term derivative liabilities in other long-term liabilities.

	December 31, 2011				December 31, 2010			
	Level 1	Level 2 (in millions)	Level 3	Total	Level 1	Level 2 (in millions)	Level 3	Total
Assets								
Current assets:								
Foreign currency derivatives	$—	$ 24	$ 4	$ 28	$—	$ 3	$ 3	$ 6
Commodity and other derivatives	2	16	3	21	—	2	3	5
Total current assets	2	40	7	49	—	5	6	11
Noncurrent assets:								
Interest rate derivatives	—	—	—	—	—	49	—	49
Cross currency derivatives	—	—	1	1	—	—	12	12
Foreign currency derivatives	—	3	58	61	—	—	27	27
Commodity and other derivatives	—	9	—	9	—	4	16	20
Total noncurrent assets	—	12	59	71	—	53	55	108
Total assets	$ 2	$ 52	$ 66	$120	$—	$ 58	$ 61	$119
Liabilities								
Current liabilities:								
Interest rate derivatives	$—	$ 97	$ 22	$119	$—	$118	$—	$118
Cross currency derivatives	—	—	5	5	—	—	2	2
Foreign currency derivatives	—	5	1	6	—	13	—	13
Commodity and other derivatives	—	17	6	23	—	—	—	—
Total current liabilities	—	119	34	153	—	131	2	133
Long-term liabilities:								
Interest rate derivatives	—	334	106	440	—	200	1	201
Cross currency derivatives	—	—	14	14	—	—	—	—
Foreign currency derivatives	—	10	10	20	—	15	8	23
Commodity and other derivatives	—	13	50	63	—	—	1	1
Total long-term liabilities	—	357	180	537	—	215	10	225
Total liabilities	$—	$476	$214	$690	$—	$346	$ 12	$358

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

	December 31, 2011			December 31, 2010		
	Designated as Hedging Instruments	Not Designated as Hedging Instruments	Total	Designated as Hedging Instruments	Not Designated as Hedging Instruments	Total
	(in millions)			(in millions)		
Assets						
Current assets:						
Foreign currency derivatives	$ 10	$ 18	$ 28	$—	$ 6	$ 6
Commodity and other derivatives	2	19	21	—	5	5
Total current assets	12	37	49	—	11	11
Noncurrent assets:						
Interest rate derivatives	—	—	—	49	—	49
Cross currency derivatives	1	—	1	12	—	12
Foreign currency derivatives	3	58	61	—	27	27
Commodity and other derivatives	—	9	9	—	20	20
Total noncurrent assets	4	67	71	61	47	108
Total assets	$ 16	$104	$120	$ 61	$ 58	$119
Liabilities						
Current liabilities:						
Interest rate derivatives	$110	$ 9	$119	$107	$ 11	$118
Cross currency derivatives	5	—	5	2	—	2
Foreign currency derivatives	1	5	6	8	5	13
Commodity and other derivatives	—	23	23	—	—	—
Total current liabilities	116	37	153	117	16	133
Long-term liabilities:						
Interest rate derivatives	425	15	440	186	15	201
Cross currency derivatives	14	—	14	—	—	—
Foreign currency derivatives	—	20	20	—	23	23
Commodity and other derivatives	3	60	63	—	1	1
Total long-term liabilities	442	95	537	186	39	225
Total liabilities	$558	$132	$690	$303	$ 55	$358

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 December 31, 2011 and 2010, we held $3 million and $0 million, respectively, of cash collateral that we received from counterparties to our derivative positions. Beyond the cash collateral held by us, 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 December 31, 2011 and 2010, we had $16 million and $0 million, respectively, of 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 December 31, 2011 for the following types of derivative instruments:

	Accumulated Other Comprehensive Income (Loss)[1]
	(in millions)
Interest rate derivatives	$(101)
Cross currency derivatives	$ (1)
Foreign currency derivatives	$ 7
Commodity and other derivatives	$ (1)

(1) Excludes a loss of $94 million expected to be recognized as part of the sale of Cartagena, which closed on February 9, 2012, and is further discussed in Note 23—Acquisitions and Dispositions.

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 (except for the amount reclassified to foreign currency transaction gains and losses to offset the remeasurement of the foreign currency-denominated debt being hedged by the cross currency swaps), as depreciation is recognized for interest rate hedges during construction, as foreign currency transaction gains and losses are recognized for hedges of foreign currency exposure, and as electricity sales and fuel purchases are recognized for hedges of forecasted electricity and fuel transactions. These balances are included in the consolidated statements of cash flows as operating and/or investing activities based on the nature of the underlying transaction.

For the years ended December 31, 2011, 2010 and 2009, pre-tax gains (losses) of $0 million, $(1) million, and $0 million net of noncontrolling interests, respectively, were reclassified into earnings as a result of the discontinuance of a cash flow hedge because it was probable that the forecasted transaction would not occur by the end of the originally specified time period (as documented at the inception of the hedging relationship) or within an additional two-month time period thereafter.

The following table sets forth the pre-tax 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 years ended December 31, 2011, 2010 and 2009:

	Gains (Losses) Recognized in AOCL			Consolidated Statement of Operations	Gains (Losses) Reclassified from AOCL into Earnings		
	2011	2010	2009		2011	2010	2009
	(in millions)				(in millions)		
Interest rate derivatives	$(475)[1]	$(243)[1]	$ 49	Interest expense	$(125)[2]	$(108)[2]	$ (72)[2]
				Non-regulated cost of sales	(3)	(2)	—
				Net equity in earnings of affiliates	(4)	(1)	—
Cross currency derivatives	(36)	11	48	Interest expense	(10)	(1)	2
				Foreign currency transaction gains (losses)	(16)	25	43
Foreign currency derivatives	24	(9)	2	Foreign currency transaction gains (losses)	1	(3)	—
Commodity and other derivatives	—	(8)	120	Non-regulated revenue	—[3]	—[3]	3[3]
				Non-regulated cost of sales	(2)	—	—
Total	$(487)	$(249)	$219		$(159)	$ (90)	$ (24)

(1) Includes $(49) million and $(29) million related to Cartagena for the years ended December 31, 2011 and 2010, respectively, which was consolidated prospectively beginning January 1, 2010 under VIE accounting guidance.

(2) Includes amounts that were reclassified from AOCL related to derivative instruments that previously, but no longer, qualify for cash flow hedge accounting. Excludes $0 million, $(113) million and $(35) million related to discontinued operations for the years ended December 31, 2011, 2010 and 2009, respectively.

(3) Excludes $0 million, $11 million and $190 million related to discontinued operations for the years ended December 31, 2011, 2010 and 2009, respectively.

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 years ended December 31, 2011, 2010 and 2009:

	Classification in Consolidated Statement of Operations	Gains (Losses) Recognized in Earnings		
		2011	2010	2009
		(in millions)		
Interest rate derivatives	Interest expense	$ (6)	$ (15)	$ (8)
	Net equity in earnings of affiliates	(2)	—[1]	(1)
Cross currency derivatives	Interest expense	(4)	5	(11)
Foreign currency derivatives	Foreign currency transaction gains (losses)	—[1]	—[1]	—[1]
Total		$ (12)	$ (10)	$ (20)

(1) De minimis amount.

The following table sets forth the pre-tax gains (losses) recognized in earnings related to derivative instruments not designated as hedging instruments under the accounting standards for derivatives and hedging, for the years ended December 31, 2011, 2010 and 2009:

	Classification in Consolidated Statement of Operations	Gains (Losses) Recognized in Earnings		
		2011	2010	2009
			(in millions)	
Interest rate derivatives	Interest expense	$ (4)	$ (9)	$ (26)
Foreign currency derivatives	Foreign currency transaction gains (losses)	57	(36)	(38)
	Net equity in earnings of affiliates	—	(2)	—
Commodity and other derivatives	Non-regulated revenue	(71)	21	1
	Regulated revenue	1	—	—
	Non-regulated cost of sales	(9)	5	(30)
	Regulated cost of sales	(5)	—	—
Total		$ (31)	$ (21)	$ (93)

In addition, DPL and IPL have 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 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 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 years ended December 31, 2011 and 2010:

	2011	2010
	(in millions)	
(Increase) decrease in regulatory assets	$(5)	$(3)
Increase (decrease) in regulatory liabilities	$ 8	$ 1

Credit Risk-Related Contingent Features

Gener, our generation 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 agreements. 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 loss of the swaps (excluding credit valuation adjustments), which was $18 million at December 31, 2011. The mark-to-market value of the swaps was in a net asset position at December 31, 2010. As of December 31, 2011 and 2010, Gener had not posted collateral to support these swaps.

DPL, our utility in Ohio, has certain over-the-counter commodity derivative contracts under master netting agreements that contain provisions that require its debt to maintain an investment-grade credit rating from credit rating agencies. If its debt were to fall below investment grade, the business would be in violation of these provisions, and the counterparties to the derivative contracts could request immediate payment or demand immediate and ongoing full overnight collateralization of the mark-to-market loss (excluding credit valuation adjustments), which was $28 million as of December 31, 2011. As of December 31, 2011, DPL had posted $16 million of cash collateral directly with third parties and in a broker margin account and held $3 million of cash collateral that it received from counterparties to its derivative instruments that were in an asset position.

7. INVESTMENTS IN AND ADVANCES TO AFFILIATES

The following table summarizes the relevant effective equity ownership interest and carrying values for the Company's investments accounted for under the equity method as of December 31, 2011 and 2010.

		December 31,			
Affiliate	Country	2011	2010	2011	2010
		Carrying Value (in millions)		Ownership Interest %	
AES Solar Energy Ltd.	Europe	$ 225	$ 256	50%	50%
AES Solar Power LLC	United States	91	8	50%	50%
AES Solar Power, PR, LLC	Puerto Rico	8	—	50%	0%
Barry[(1)]	United Kingdom	—	—	100%	100%
CET[(1)]	Brazil	14	22	72%	72%
Chigen affiliates[(2)]	China	30	146	25%	25%
China Wind[(3)]	China	75	69	49%	49%
Elsta	Netherlands	197	202	50%	50%
Entek	Turkey	121	—	50%	0%
Guacolda	Chile	186	149	35%	35%
IC Ictas Energy Group	Turkey	161	151	51%	51%
InnoVent[(1)]	France	32	31	40%	40%
JHRH	China	59	39	49%	35%
OPGC	India	203	224	49%	49%
Trinidad Generation Unlimited[(1)]	Trinidad	19	20	10%	10%
Other affiliates		1	3		
Total investments in and advances to affiliates		$1,422	$1,320		

(1) Represent VIEs in which the Company holds a variable interest, but is not the primary beneficiary.
(2) Represent our investments in Chengdu AES Kaihua Gas Turbine Company Ltd. and Yangcheng International Power Generating Co. Ltd.
(3) Represent our investments in Guohua AES (Huanghua) Wind Power Co. Ltd., Guohua AES (Hulunbeier) Wind Power Co. Ltd., Guohua AES (Chenba'-erhu) Wind Power Co. Ltd., and Guohua AES (Xinba'-erhu) Wind Power Co. Ltd.

AES Solar Energy Ltd.— In the fourth quarter of 2011, AES Solar Energy Ltd. ("AES Solar"), recognized a $40 million other-than-temporary impairment of a cost method investment in a manufacturer of solar panels. The Company's share of impairment was $20 million, which was recorded within "Net equity in earnings of affiliates" in the Consolidated Statement of Operations.

AES Solar Power, PR, LLC—In June 2011, the Company formed AES Solar Power, PR LLC., a joint venture with R/C PR Investment Partnership L.P., a wholly-owned subsidiary of Riverstone/Carlyle Renewable

Energy Partners II, LP. This joint venture was created to develop and construct a 24 MW project in Guayama, Puerto Rico. The investment balance at December 31, 2011 was $8 million.

AES Barry Ltd.—The Company holds a 100% ownership interest in AES Barry Ltd. (“Barry”), a dormant entity in the United Kingdom that disposed of its generation and other operating assets. Due to a debt agreement, no material financial or operating decisions can be made without the banks’ consent, and the Company does not control Barry. As of December 31, 2011 and 2010, other long-term liabilities included $52 million and $53 million, respectively, related to this debt agreement.

Cayman Energy Trader (“CET”)—In 2010, the Company transferred its 14.8% voting interest in Companhia Energética de Minas Gerais (“CEMIG”), an integrated utility in Brazil, through SEB, a Brazilian subsidiary, to a third party. The buyer also assumed a debt with Banco Nacional de Desenvolvimento Econômico e Social (“BNDES”) in the amount of approximately $1.4 billion (the “BNDES Loan”) including all unpaid interest and penalties. In exchange, SEB received $25 million and obtained a full release from any claims of BNDES and originating from the BNDES Loan. CEMIG was previously accounted for as an equity method investment due to the Company’s representation on its board of directors. The transfer resulted in the recognition of a $115 million pre-tax gain reflected in “Net equity in earnings of affiliates” in the Consolidated Statement of Operations for the year ended December 31, 2010. Additionally, $70 million of net tax expense resulting from the CEMIG transfer was recorded as “income tax expense,” rather than equity earnings, since the expense is attributable to a consolidated corporate level partner in the CEMIG investment. The Company retains its ownership in CET.

Chigen affiliates—In 2011, the Company recognized an other-than-temporary impairment of $74 million on Yangcheng, an equity method investment in China. See Note 8—*Other Non-Operating Expense* for further information.

Entek— In February 2011, the Company acquired a 49.6% interest in Entek Elektrik Uretim A.S. (“Entek”) for approximately $136 million. Additional purchase consideration of $13 million was paid in May 2011, increasing the total purchase consideration to $149 million. Entek owns and operates two gas-fired generation facilities in Turkey with an aggregate capacity of 312 MW 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.

Jianghe Rural Electrification Development Co., LTD (“JHRH”)—On June 3, 2010, the Company acquired a 35% ownership in this joint venture which operates seven hydro plants in China. In April 2011, the Company acquired an additional 14% ownership for $15 million, increasing its total ownership to 49%.

Trinidad Generation Unlimited (“TGU”)—Although the Company’s ownership in TGU is 10%, the Company accounts for the investment as an equity method investment due to the Company’s ability to exercise significant influence through the supermajority vote requirement for any significant future project development activities. TGU had four gas turbines commence commercial operations in 2011.

Summarized Financial Information

The following tables summarize financial information of the Company's 50%-or-less owned affiliates and majority-owned unconsolidated subsidiaries that are accounted for using the equity method.

	50%-or-less Owned Affiliates			Majority-Owned Unconsolidated Subsidiaries		
Years ended December 31,	**2011**	**2010**	**2009**	**2011**	**2010**	**2009**
	(in millions)			(in millions)		
Revenue	$1,668	$1,341	$1,229	$ 24	$ 20	$158
Gross margin	258	207	240	24	18	71
Net income (loss)	(5)	100	110	(5)	7	(5)

December 31,	**2011**	**2010**	**2011**	**2010**
	(in millions)		(in millions)	
Current assets	$1,182	$ 948	$ 58	$114
Noncurrent assets	4,298	4,131	519	646
Current liabilities	899	687	109	144
Noncurrent liabilities	1,720	1,597	269	242
Noncontrolling interests	(240)	(206)	—	125
Stockholders' equity	3,101	3,001	199	249

At December 31, 2011, retained earnings included $136 million related to the undistributed earnings of the Company's 50%-or-less owned affiliates. Distributions received from these affiliates were $36 million, $49 million and $35 million for the years ended December 31, 2011, 2010 and 2009, respectively. As of December 31, 2011, the aggregate carrying amount of our investments in equity affiliates exceeded the underlying equity in their net assets by $145 million.

Refer to Item 1 of this Form 10-K for additional information on these affiliates.

8. OTHER NON-OPERATING EXPENSE

Other non-operating expense of $82 million for the year ended December 31, 2011 primarily consisted of other-than-temporary impairments of equity method investments in China. During the third quarter of 2011 as part of the quarterly close process, the Company evaluated its investment in Yangcheng, a 2,100 MW coal-fired plant in China, for other-than-temporary-impairment. AES owns a 25% interest in Yangcheng and the remaining equity interest in the venture is held by Chinese partners. During the nine months ended September 30, 2011, coal prices continued an upward trend in China, thereby reducing the operating margin of coal generation facilities. During this time, there was no corresponding increase in tariffs to compensate for higher coal prices. Power prices in China are tightly regulated by the national and provincial governments, which often limit power generators' ability to pass through increases in fuel costs to customers. In addition, under the Yangcheng venture agreement, AES will surrender its equity interest to the venture partners in 2016 without additional compensation. During the nine months ended September 30, 2011, management continued to monitor the situation and in the third quarter determined that it was unlikely that there would be a reversal in the trends in coal prices during the remaining term of the venture. Accordingly, in September 2011, management revised downward its forecasts of earning and cash flows over the remaining term of the venture. The revised forecasts were significantly lower than management's earlier estimates such that the carrying amount of the investment in Yangcheng was considered to have incurred an other-than-temporary-impairment. In determining the fair value of our investment, management used a discounted cash flow analysis based on probability-weighted revised cash distribution forecasts under multiple scenarios. As of September 30, 2011, Yangcheng had a carrying amount of $100 million which was written down to its estimated fair value of $26 million, and the difference was recognized as other non-operating expense.

Other non-operating expense of $7 million for the year ended December 31, 2010 primarily consisted of an other-than-temporary impairment of an equity method investment. During the second quarter of 2010, AES decided to not pursue its investment in a project to generate environmental offset credits and recognized the other-than-temporary impairment.

Other non-operating expense of $12 million for the year ended December 31, 2009 primarily consisted of impairment charges on a cost method investment in a company developing a commercial facility for a "blue gas" (coal to gas) technology project.

9. GOODWILL AND OTHER INTANGIBLE ASSETS

The following table summarizes the changes in the carrying amount of goodwill, by segment for the years ended December 31, 2011 and 2010.

	Latin America - Generation	Latin America - Utilities	North America - Generation	North America - Utilities	Europe - Generation	Asia - Generation	Corporate and Other	Total
Balance as of December 31, 2009								
Goodwill	$926	$140	$111	$ —	$ 137	$ 78	$101	$1,493
Accumulated impairment losses	(24)	(7)	(20)	—	(137)	—	(6)	(194)
Net balance	902	133	91	—	—	78	95	1,299
Impairment losses	—	—	(18)	—	—	—	(3)	(21)
Foreign currency translation and other	—	—	(10)	—	—	3	—	(7)
Balance as of December 31, 2010								
Goodwill	926	140	101	—	137	81	101	1,486
Accumulated impairment losses	(24)	(7)	(38)	—	(137)	—	(9)	(215)
Net balance	902	133	63	—	—	81	92	1,271
Impairment losses	—	—	—	—	—	(17)	—	(17)
Goodwill acquired during the year[(1)]	—	—	—	2,489	—	—	—	2,489
Foreign currency translation and other	—	—	(10)	—	—	—	—	(10)
Balance as of December 31, 2011								
Goodwill	926	140	91	2,489	137	81	101	3,965
Accumulated impairment losses	(24)	(7)	(38)	—	(137)	(17)	(9)	(232)
Net balance	$902	$133	$ 53	$2,489	$ —	$ 64	$ 92	$3,733

(1) Represents goodwill resulting from the acquisition of DPL, which was allocated to the two newly established reporting units identified within DPL. See Note 23—*Acquisitions and Dispositions* for further information.

During the third quarter of 2011, the Company identified higher coal prices and the resulting reduced operating margins in China as an impairment indicator for the goodwill at Chigen, our wholly-owned subsidiary that holds equity interests in Chinese ventures and reported in the Asia Generation segment. A significant downward revision of cash flow forecasts indicated that the fair value of Chigen reporting unit was lower than its carrying amount. As of September 30, 2011, Chigen had goodwill of $17 million. The Company performed an interim impairment evaluation of Chigen's goodwill and determined that goodwill had no implied fair value. As a result, the entire carrying amount of $17 million was recognized as goodwill impairment in the third quarter.

During the third quarter of 2010, Deepwater, our petcoke-fired merchant generation facility in Texas, reported in the North America Generation segment, incurred a goodwill impairment of $18 million. The Company determined the adverse market conditions as an impairment indicator, performed the two-step goodwill impairment test and recognized the entire $18 million carrying amount of goodwill as goodwill impairment in the third quarter.

In 2009, Kilroot, our coal fired power plant in the United Kingdom, reported in the Europe Generation segment, incurred a goodwill impairment of $118 million. Factors contributing to the impairment included: reduced profit expectations based on latest estimates of future commodity prices and reduced expectations on the recovery of cash flows on the existing plant following the Company's decision to forgo capital expenditures to meet emission allowance requirements taking effect in 2024. Additionally, one of our subsidiaries located in the Ukraine and reported within "Corporate and Other" incurred a goodwill impairment loss of $4 million.

The following tables summarize the balances comprising other intangible assets in the accompanying Consolidated Balance Sheets as of December 31, 2011 and 2010:

	December 31, 2011			December 31, 2010		
	Gross Balance	Accumulated Amortization (in millions)	Net Balance	Gross Balance	Accumulated Amortization (in millions)	Net Balance
Subject to Amortization						
Project development rights[1]	$102	$ —	$102	$117	$ —	$117
Sales concessions	156	(92)	64	162	(89)	73
Contractual payment rights[2]	69	(13)	56	65	(4)	61
Land use rights	49	(4)	45	50	(2)	48
Management rights	39	(13)	26	66	(30)	36
Emission allowances[3]	18	—	18	8	—	8
Electric security plan	88	(9)	79	—	—	—
Customer contracts	45	(3)	42	—	—	—
Customer relationships	30	—	30	—	—	—
Other[4]	71	(30)	41	70	(26)	44
Subtotal	667	(164)	503	538	(151)	387
Indefinite-Lived Intangible Assets						
Land use rights	52	—	52	51	—	51
Emission allowances[5]	4	—	4	8	—	8
Trademark/Trade name	5	—	5	—	—	—
Other	2	—	2	2	—	2
Subtotal	63	—	63	61	—	61
Total	$730	$(164)	$566	$599	$(151)	$448

(1) Represent development rights, including but not limited to, land control, various permits and right to acquire equity interests in development projects resulting from asset acquisitions by our Wind group. A portion of these development rights was recognized as a loss on disposal of discontinued operations when certain development projects were abandoned during the fourth quarter of 2011. See Note 22—*Discontinued Operations and Held for Sale Businesses* for further information.
(2) Represent legal rights to receive system reliability payments from the regulator.
(3) Acquired or purchased emission allowances are expensed when utilized and included in net income for the year.
(4) Consists of various intangible assets including PPAs and transmission rights, none of which is individually significant.
(5) Represent perpetual emission allowances without an expiration date.

The following table summarizes, by category, intangible assets acquired during the years ended December 31, 2011 and 2010:

	December 31, 2011			
	Amount (in millions)	Subject to Amortization/ Indefinite-Lived	Weighted Average Amortization Period (in years)	Amortization Method
Electric security plan[2]	$ 88	Subject to amortization	1	Straight line
Customer relationship[1][3]	30	Subject to amortization	12	Straight line
Customer contracts[1][4]	45	Subject to amortization	3	Other
Trademark/Trade name[1][5]	5	Indefinite-lived	N/A	N/A
Other	4	Subject to amortization	Various	As utilized
Total	$172			

	December 31, 2010			
	Amount (in millions)	Subject to Amortization/ Indefinite-Lived	Weighted Average Amortization Period (in years)	Amortization Method
Project development rights	$141	Subject to amortization	Various	Straight line
Contractual payment rights	65	Subject to amortization	10	Straight line
Emission allowances	14	Subject to amortization	Various	As utilized
Land use rights	7	Indefinite-lived	N/A	N/A
Total	$227			

(1) Represents intangible assets arising from the acquisition of DPL. See Note 23—*Acquisitions and Dispositions* for further information.
(2) Electric Security Plan is a rate plan for the supply and pricing of electric generation service applicable to Ohio's electric utilities under state law. It provides a level of price stability to consumers of electricity as compared to market-based electricity prices. The plan was recognized as an intangible asset since the prices under the plan are higher than market prices charged by competitive retailers or CRES.

(3) Customer relationships represent the value assigned to customer information possessed by DPL in the preliminary purchase price allocation, where DPL has regular contact with the customer, and the customer has the ability to make direct contact with DPL. See Note 23—*Acquisitions and Dispositions* for further information.

(4) The amortization method used reflects the pattern in which the economic benefits of the intangible asset are consumed.

(5) Trademarks/Trade name represent the value assigned to trade name of DPLER, DPL's subsidiary engaged in competitive retail business in Ohio.

The following table summarizes the estimated amortization expense, broken down by intangible asset category, for 2012 through 2016:

	Estimated amortization expense				
	2012	**2013**	**2014**	**2015**	**2016**
	(in millions)				
Contractual payment rights	$ 9	$ 9	$ 9	$ 9	$ 3
Sales concessions	6	6	6	6	5
Customer relationships & contracts	35	11	4	3	3
Electric security plan	79	—	—	—	—
All other	9	6	4	4	4
Total	$138	$ 32	$ 23	$ 22	$ 15

Intangible asset amortization expense was $36 million, $14 million and $16 million for the years ended December 31, 2011, 2010 and 2009, respectively.

10. REGULATORY ASSETS & LIABILITIES

The Company has recorded regulatory assets and liabilities that it expects to pass through to its customers in accordance with, and subject to, regulatory provisions as follows:

	December 31, 2011	December 31, 2010	Recovery Period
	(in millions)		
REGULATORY ASSETS			
Current regulatory assets:			
Brazil tariff recoveries:(1)			
Energy purchases	$ 79	$ 62	Over tariff reset period
Transmission costs, regulatory fees and other	185	82	Over tariff reset period
El Salvador tariff recoveries(2)	108	67	Over tariff reset period
Other(3)	19	1	Various
Total current regulatory assets	391	212	
Noncurrent regulatory assets:			
Defined benefit pension obligations at IPL and DPL(4)(5)	399	235	Various
Income taxes recoverable from customers(4)(6)	76	66	Various
Brazil tariff recoveries:(1)			
Energy purchases	84	18	Over tariff reset period
Transmission costs, regulatory fees and other	86	32	Over tariff reset period
Deferred Midwest ISO costs(7)	80	80	To be determined
Other(3)	122	39	Various
Total noncurrent regulatory assets	847	470	
TOTAL REGULATORY ASSETS	$1,238	$ 682	
REGULATORY LIABILITIES			
Current regulatory liabilities:			
Brazil tariff reset adjustment(8)	$ 190	$ —	To be determined
Efficiency program costs(9)	29	58	Over tariff reset period
Brazil tariff recoveries:(1)			
Energy purchases	305	118	Over tariff reset period
Transmission costs, regulatory fees and other	172	71	Over tariff reset period
Other(10)	37	37	Various
Total current regulatory liabilities	733	284	
Noncurrent regulatory liabilities:			
Asset retirement obligations(11)	649	509	Over life of assets
Brazil special obligations(12)	422	435	To be determined
Brazil tariff recoveries:(1)			
Energy purchases	76	69	Over tariff reset period
Transmission costs, regulatory fees and other	64	57	Over tariff reset period
Efficiency program costs(9)	44	54	Over tariff reset period
Other(10)	24	8	Various
Total noncurrent regulatory liabilities	1,279	1,132	
TOTAL REGULATORY LIABILITIES	$2,012	$1,416	

(1) Recoverable per National Electric Energy Agency ("ANEEL") regulations through the Annual Tariff Adjustment ("IRT"). These costs are generally non-controllable costs and primarily consist of purchased electricity, energy transmission costs and sector costs that are considered volatile. These costs are recovered in 24 installments through the annual IRT process and are amortized over the tariff reset period.

(2) Deferred fuel costs incurred by our El Salvador subsidiaries associated with purchase of energy from the El Salvador spot market and the power generation plants. In El Salvador, the deferred fuel adjustment represents the variance between the actual fuel costs and the fuel costs recovered in the tariffs. The variance is recovered semi-annually at the tariff reset period.

(3) Includes assets with and without a rate of return. Other current regulatory assets that did not earn a rate of return were $12 million and $0 million, as of December 31, 2011 and 2010, respectively. Other noncurrent regulatory assets that did not earn a rate of return were $37 million and $14 million, as of December 31, 2011 and 2010, respectively. Other Current and Noncurrent Regulatory Assets primarily consist of:

- Unamortized losses on long-term debt reacquired or redeemed in prior periods at IPL and DPL, which are amortized over the lives of the original issues in accordance with the FERC and PUCO rules.
- Unamortized carrying charges and certain other costs related to Petersburg unit 4 at IPL.
- Deferred storm costs incurred to repair 2008 storm damage at DPL, which have been deferred until such time that DPL seeks recovery in a future rate proceeding.

(4) Past expenditures on which the Company does not earn a rate of return.

(5) The regulatory accounting standards allow the defined pension and postretirement benefit obligation to be recorded as a regulatory asset equal to the previously unrecognized actuarial gains and losses and prior service costs that are expected to be recovered through future rates. Pension expense is recognized based on the plan's actuarially determined pension liability. Recovery of costs is probable, but not yet determined. Pension contributions made by our Brazilian subsidiaries are not included in regulatory assets as those contributions are not covered by the established tariff in Brazil.

(6) Probable of recovery through future rates, based upon established regulatory practices, which permit the recovery of current taxes. This amount is expected to be recovered, without interest, over the period as book-tax temporary differences reverse and become current taxes.

(7) Transmission service costs and other administrative costs from IPL's participation in the Midwest ISO market, which are recoverable but do not earn a rate of return. Recovery of costs is probable, but the timing is not yet determined.

(8) In July 2011, the Brazilian energy regulator (the "Regulator") postponed the periodic review and reset of a component of Eletropaulo's regulated tariff, which determines the margin to be earned by Eletropaulo. The review and reset of this tariff component is performed every four years. From July 2011 through December 2011, Eletropaulo continued to invoice customers under the existing tariff rate, as required by the Regulator. Management believes that it is probable that the new tariff rate will be lower than the existing tariff rate, resulting in future refunds to customers, and has estimated the amount of this liability. Accordingly, as of December 31, 2011, Eletropaulo recognized a regulatory liability. It is at least reasonably possible that future events confirming the final amount of the regulatory liability or a change in the estimated amount of the liability will occur in the near term as the periodic review and tariff reset process progresses with the Regulator in 2012. The primary factor in the ongoing discussions between Eletropaulo and the Regulator that causes the estimate to be sensitive to change is the regulatory asset base which will be used by the Regulator to determine the return included in the revised tariff. The final amount of the regulatory liability may differ from the estimated amount recognized as of December 31, 2011.

(9) Payments received for costs expected to be incurred to improve the efficiency of our plants in Brazil that are refunded as part of the IRT.

(10) Other Current and Noncurrent Regulatory Liabilities primarily consist of the cost incurred by electricity generators due to variance in energy prices during rationing periods ("Free Energy"). Our Brazilian subsidiaries are authorized to recover or refund this cost associated with monthly energy price variances between the wholesale energy market prices owed to the power generation plants producing Free Energy and the capped price reimbursed by the local distribution companies which are passed through to the final customers through energy tariffs.

(11) Obligations for removal costs which do not have an associated legal retirement obligation as defined by the accounting standards on asset retirement obligations.

(12) Obligations established by ANEEL in Brazil associated with electric utility concessions and represent amounts received from customers or donations not subject to return. These donations are allocated to support energy network expansion and to improve utility operations to meet customers' needs. The term of the obligation is established by ANEEL. Settlement shall occur when the concession ends.

The current regulatory assets and liabilities are recorded in "Other current assets" and "Accrued and other liabilities," respectively, on the accompanying Consolidated Balance Sheets. The noncurrent regulatory assets and liabilities are recorded in "Other noncurrent assets" and "Other long-term liabilities," respectively, in the accompanying Consolidated Balance Sheets.

The following table summarizes regulatory assets by region as of December 31, 2011 and 2010:

	December 31,	
	2011	2010
	(in millions)	
Latin America	$ 546	$265
North America	692	417
Total regulatory assets	$1,238	$682

The following table summarizes regulatory liabilities by region as of December 31, 2011 and 2010:

	December 31,	
	2011	2010
	(in millions)	
Latin America	$1,333	$ 890
North America	679	526
Total regulatory liabilities	$2,012	$1,416

11. DEBT

The Company has two types of debt reported on its Consolidated Balance Sheets: 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 December 31, 2011 and 2010:

	December 31,			
	2011		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Non-recourse debt	$16,088	$16,425	$14,176	$14,506
Recourse debt	6,485	6,640	4,612	4,868
Total debt	$22,573	$23,065	$18,788	$19,374

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 December 31, 2011 and 2010. The Company is not aware of any factors that would significantly affect the estimated fair value amounts since December 31, 2011.

NON-RECOURSE DEBT

The following table summarizes the carrying amount and terms of non-recourse debt as of December 31, 2011 and 2010:

NON-RECOURSE DEBT	Interest Rate[1]	Maturity	December 31, 2011	December 31, 2010
			(in millions)	
VARIABLE RATE:[2]				
Bank loans	2.95%	2012 – 2028	$ 3,453	$ 3,079
Notes and bonds	11.70%	2012 –2040	2,178	2,982
Debt to (or guaranteed by) multilateral, export credit agencies or development banks[3]	3.30%	2012 – 2027	1,989	1,848
Other	3.83%	2012 – 2041	321	363
FIXED RATE:				
Bank loans	8.24%	2012 – 2023	412	424
Notes and bonds	6.56%	2012 – 2061	7,021	4,829
Debt to (or guaranteed by) multilateral, export credit agencies or development banks[3]	6.57%	2012 – 2027	513	467
Other	11.85%	2012 – 2039	201	184
SUBTOTAL			$16,088[4]	$14,176[4]
Less: Current maturities			(2,152)	(2,533)
TOTAL			$13,936	$11,643

(1) Weighted average interest rate at December 31, 2011.

(2) The Company has interest rate swaps and interest rate option agreements in an aggregate notional principal amount of approximately $3.6 billion on non-recourse debt outstanding at December 31, 2011. The swap agreements economically change the variable interest rates on the portion of the debt covered by the notional amounts to fixed rates ranging from approximately 1.44% to 6.98%. The option agreements fix interest rates within a range from 1.00% to 7.00%. The agreements expire at various dates from 2016 through 2028.

(3) Multilateral loans include loans funded and guaranteed by bilaterals, multilaterals, development banks and other similar institutions.

(4) Non-recourse debt of $704 million and $945 million as of December 31, 2011 and 2010, respectively, was excluded from non-recourse debt and included in current and long-term liabilities of held for sale and discontinued businesses in the accompanying Consolidated Balance Sheets.

Non-recourse debt as of December 31, 2011 is scheduled to reach maturity as set forth in the table below:

December 31,	Annual Maturities
	(in millions)
2012	$ 2,152
2013	1,389
2014	1,697
2015	851
2016	2,301
Thereafter	7,698
Total non-recourse debt	$16,088

As of December 31, 2011, AES subsidiaries with facilities under construction had a total of approximately $1.4 billion of committed but unused credit facilities available to fund construction and other related costs. Excluding these facilities under construction, AES subsidiaries had approximately $1.2 billion in a number of available but unused committed revolving credit lines to support their working capital, debt service reserves and other business needs. These credit lines can be used in one or more of the following ways: solely for borrowings; solely for letters of credit; or a combination of these uses. The weighted average interest rate on borrowings from these facilities was 14.75% at December 31, 2011.

On October 3, 2011, Dolphin Subsidiary II, Inc. (“Dolphin II”), a newly formed, wholly-owned special purpose indirect subsidiary of AES, entered into an indenture (the “Indenture”) with Wells Fargo Bank, N.A. (the “Trustee”) as part of its issuance of $450 million aggregate principal amount of 6.50% senior notes due 2016 (the “2016 Notes”) and $800 million aggregate principal amount of 7.25% senior notes due 2021 (the “7.25% 2021 Notes”, together with the 2016 Notes, the “notes”) to finance the acquisition (the “Acquisition”) of DPL. Upon closing of the acquisition on November 28, 2011, Dolphin II was merged into DPL with DPL being the surviving entity and obligor. The 2016 Notes and the 7.25% 2021 Notes are included under “Notes and bonds” in the non-recourse detail table above. See Note 23—*Acquisitions and Dispositions* for further information.

Interest on the 2016 Notes and the 7.25% 2021 Notes accrues at a rate of 6.50% and 7.25% per year, respectively, and is payable on April 15 and October 15 of each year, beginning April 15, 2012. Prior to September 15, 2016 with respect to the 2016 Notes and July 15, 2021 with respect to the 7.25% 2021 Notes, DPL may redeem some or all of the 2016 Notes or 7.25% 2021 Notes at par, plus a “make-whole” amount set forth in the Indenture and accrued and unpaid interest. At any time on or after September 15, 2016 or July 15, 2021 with respect to the 2016 Notes and 7.25% 2021 Notes, respectively, DPL may redeem some or all of the 2016 Notes or 7.25% 2021 Notes at par plus accrued and unpaid interest. The proceeds from issuance of the notes were used to partially finance the DPL acquisition.

Non-Recourse Debt Covenants, Restrictions and Defaults

The terms of the Company's non-recourse debt include certain financial and non-financial covenants. These covenants are limited to subsidiary activity and vary among the subsidiaries. These covenants may include but are not limited to maintenance of certain reserves, minimum levels of working capital and limitations on incurring additional indebtedness. Compliance with certain covenants may not be objectively determinable.

As of December 31, 2011 and 2010, approximately $639 million and $595 million, respectively, of restricted cash was maintained in accordance with certain covenants of the non-recourse debt agreements, and these amounts were included within "Restricted cash" and "Debt service reserves and other deposits" in the accompanying Consolidated Balance Sheets.

Various lender and governmental provisions restrict the ability of certain of the Company's subsidiaries to transfer their net assets to the Parent Company. Such restricted net assets of subsidiaries amounted to approximately $3.3 billion at December 31, 2011.

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

Subsidiary	Primary Nature of Default	December 31, 2011 Default	December 31, 2011 Net Assets
		(in millions)	
Maritza	Covenant	$ 905	$204
Sonel	Covenant	331	305
Kelanitissa	Covenant	16	48
Total		$1,252	

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 December 31, 2011 in order for such defaults 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 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 a bankruptcy or 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.

RECOURSE DEBT

The following table summarizes the carrying amount and terms of recourse debt of the Company as of December 31, 2011 and 2010:

RECOURSE DEBT	Interest Rate	Maturity	December 31, 2011	December 31, 2010
			(in millions)	
Senior Secured Term Loan	LIBOR + 1.75%	2011	$ —	$ 200
Senior Unsecured Note	8.875%	2011	—	129
Senior Unsecured Note	8.375%	2011	—	134
Senior Unsecured Note	7.75%	2014	500	500
Revolving Loan under Senior Secured Credit Facility[1]	LIBOR + 3.00%	2015	295	—
Senior Unsecured Note	7.75%	2015	500	500
Senior Unsecured Note	9.75%	2016	535	535
Senior Unsecured Note	8.00%	2017	1,500	1,500
Senior Secured Term Loan	LIBOR + 3.25%	2018	1,042	—
Senior Unsecured Note	8.00%	2020	625	625
Senior Unsecured Note	7.375%	2021	1,000	—
Term Convertible Trust Securities	6.75%	2029	517	517
Unamortized discounts			(29)	(28)
SUBTOTAL			$6,485	$4,612
Less: Current maturities			(305)	(463)
Total			$6,180	$4,149

(1) Subsequent to year end the loan was substantially repaid and is expected to be repaid in full prior to March 31, 2012.

Recourse debt as of December 31, 2011 is scheduled to reach maturity as set forth in the table below:

December 31,	Annual Maturities
	(in millions)
2012	$ 305
2013	11
2014	509
2015	511
2016	523
Thereafter	4,626
Total recourse debt	$6,485

Recourse Debt Transactions

During the year ended December 31, 2011, the Company issued recourse debt of $2.05 billion as outlined below. The proceeds of the debt were used to partially finance the Company's acquisition of DPL as discussed further in Note 23—*Acquisitions and Dispositions*.

On May 27, 2011, the Company secured a $1.05 billion term loan under a senior secured credit facility (the "senior secured term loan"). The senior secured term loan bears annual interest, at the Company's option, at a variable rate of LIBOR plus 3.25% or Base Rate plus 2.25%, and matures in 2018. The senior secured term loan is subject to certain customary representations, covenants and events of default.

On June 15, 2011, the Company issued $1 billion aggregate principal amount of 7.375% senior unsecured notes maturing July 1, 2021 (the "7.375% 2021 Notes"). Upon a change of control, the Company must offer to repurchase the 7.375% 2021 Notes at a price equal to 101% of principal, plus accrued and unpaid interest. The 7.375% 2021 Notes are also subject to certain covenants restricting the ability of the Company to incur additional secured debt; to enter into sale-lease back transactions; to consolidate, merge, convey or transfer substantially all of its assets; as well as other covenants and events of default that are customary for debt securities similar to the 7.375% 2021 Notes. The Company entered into interest rate locks in May 2011 to hedge the risk of changes in LIBOR until the issuance of the 7.375% 2021 Notes. The Company paid $24 million to settle those interest rate locks as of June 15, 2011. The payment was recognized in accumulated other comprehensive loss and is being amortized over the life of the 7.375% 2021 Notes as an adjustment to interest expense using the effective yield method.

Recourse Debt Covenants and Guarantees

Certain of the Company's obligations under the senior secured credit facility are guaranteed by its direct subsidiaries through which the Company owns its interests in the AES Shady Point, AES Hawaii, AES Warrior Run and AES Eastern Energy businesses. On December 30, 2011, AES Eastern Energy filed for bankruptcy and was deconsolidated. See Note 1—*General and Summary of Significant Accounting Policies* for additional information. The Company's obligations under the senior secured credit facility are, subject to certain exceptions, secured by:

(i) all of the capital stock of domestic subsidiaries owned directly by the Company and 65% of the capital stock of certain foreign subsidiaries owned directly or indirectly by the Company; and

(ii) certain intercompany receivables, certain intercompany notes and certain intercompany tax sharing agreements.

The senior secured credit facility is subject to mandatory prepayment under certain circumstances, including the sale of a guarantor subsidiary. In such a situation, the net cash proceeds from the sale of a Guarantor or any of its subsidiaries must be applied pro rata to repay the term loan using 60% of net cash proceeds, reduced to 50% when and if the parent's recourse debt to cash flow ratio is less than 5:1. The lenders have the option to waive their pro rata redemption.

The senior secured credit facility contains customary covenants and restrictions on the Company's ability to engage in certain activities, including, but not limited to, limitations on other indebtedness, liens, investments and guarantees; limitations on restricted payments such as shareholder dividends and equity repurchases; restrictions on mergers and acquisitions, sales of assets, leases, transactions with affiliates and off-balance sheet or derivative arrangements; and other financial reporting requirements.

The senior secured credit facility also contains financial covenants requiring the Company to maintain certain financial ratios including a cash flow to interest coverage ratio, calculated quarterly, which provides that a minimum ratio of the Company's adjusted operating cash flow to the Company's interest charges related to recourse debt of 1.3× must be maintained at all times and a recourse debt to cash flow ratio, calculated quarterly, which provides that the ratio of the Company's total recourse debt to the Company's adjusted operating cash flow must not exceed a maximum at any time of 7.5× at December 31, 2011.

The terms of the Company's senior unsecured notes and senior secured credit facility contain certain covenants including, without limitation, limitation on the Company's ability to incur liens or enter into sale and leaseback transactions.

TERM CONVERTIBLE TRUST SECURITIES

Between 1999 and 2000, AES Trust III, a wholly owned special purpose business trust, issued approximately 10.35 million of $3.375 Term Convertible Preferred Securities ("TECONS") (liquidation value $50) for total proceeds of $517 million and concurrently purchased $517 million of 6.75% Junior Subordinated Convertible Debentures due 2029 (the "6.75% Debentures" of the Company). The TECONS are consolidated and classified as long-term recourse debt on the Company's Consolidated Balance Sheet.

AES, at its option, can redeem the 6.75% Debentures which would result in the required redemption of the TECONS issued by AES Trust III, currently for $50 per TECON. The TECONS must be redeemed upon maturity of the 6.75% Debentures. The TECONS are convertible into the common stock of AES at each holder's option prior to October 15, 2029 at the rate of 1.4216, representing a conversion price of $35.17 per share. The maximum number of shares of common stock AES would be required to issue should all holders decide to convert their securities would be 14.7 million shares.

Dividends on the TECONS are payable quarterly at an annual rate of 6.75%. The Trust is permitted to defer payment of dividends for up to 20 consecutive quarters, provided that the Company has exercised its right to defer interest payments under the corresponding debentures or notes. During such deferral periods, dividends on the TECONS would accumulate quarterly and accrue interest, and the Company may not declare or pay dividends on its common stock. AES has not exercised the option to defer any dividends at this time and all dividends due under the Trust have been paid.

AES Trust III is a VIE under the relevant consolidation accounting guidance. AES' obligations under the 6.75% Debentures and other relevant trust agreements, in aggregate, constitute a full and unconditional guarantee by AES of the TECON Trusts' obligations. Accordingly, AES consolidates AES Trust III. As of December 31, 2011 and 2010, the sole assets of AES Trust III are the 6.75% Debentures.

12. COMMITMENTS

The following disclosures exclude any businesses classified as discontinued operations or held-for-sale.

OPERATING LEASES—As of December 31, 2011, the Company was obligated under long-term non-cancelable operating leases, primarily for certain transmission lines, office rental and site leases. Rental expense for lease commitments under these operating leases for the years ended December 31, 2011, 2010 and 2009 was $63 million, $56 million and $60 million, respectively.

The table below sets forth the future minimum lease commitments under these operating leases as of December 31, 2011 for 2012 through 2016 and thereafter:

December 31,	Future Commitments for Operating Leases
	(in millions)
2012	$ 57
2013	57
2014	55
2015	54
2016	54
Thereafter	730
Total	$1,007

CAPITAL LEASES—Several AES subsidiaries lease operating and office equipment and vehicles that are considered capital lease transactions. These capital leases are recognized in Property, Plant and Equipment within "Electric generation and distribution assets" and primarily relate to transmission lines at our subsidiaries in Brazil. The gross value of the leased assets as of December 31, 2011 and 2010 was $95 million and $97 million, respectively.

The following table summarizes the future minimum lease payments under capital leases together with the present value of the net minimum lease payments as of December 31, 2011 for 2012 through 2016 and thereafter:

December 31,	Future Minimum Lease Payments
	(in millions)
2012	$ 14
2013	11
2014	10
2015	9
2016	9
Thereafter	125
Total	$178
Less: Imputed interest	106
Present value of total minimum lease payments	$ 72

CONTRACTS—Operating subsidiaries of the Company have entered into contracts for the purchase of electricity from third parties that primarily include energy auction agreements at our Brazil subsidiaries with extended terms from 2012 through 2028 and in some cases are subject to variable quantities or prices. Purchases in the years ended December 31, 2011, 2010 and 2009 were approximately $2.5 billion, $2.4 billion and $2.1 billion, respectively.

The table below sets forth the future minimum commitments under these electricity purchase contracts at December 31, 2011 for 2012 through 2016 and thereafter:

December 31,	Future Commitments for Electricity Purchase Contracts
	(in millions)
2012	$ 2,800
2013	2,412
2014	2,034
2015	1,995
2016	1,979
Thereafter	23,887
Total	$35,107

Operating subsidiaries of the Company have entered into various long-term contracts for the purchase of fuel subject to termination only in certain limited circumstances and in some cases are subject to variable quantities or prices. Purchases in the years ended December 31, 2011, 2010 and 2009 were $1.7 billion, $1.7 billion and $1.2 billion, respectively.

The table below sets forth the future minimum commitments under these fuel contracts as of December 31, 2011 for 2012 through 2016 and thereafter:

December 31,	Future Commitments for Fuel Contracts
	(in millions)
2012	$ 1,980
2013	1,187
2014	790
2015	663
2016	661
Thereafter	4,875
Total	$10,156

The Company's subsidiaries have entered into other various long-term contracts. These contracts are mainly for construction projects, service and maintenance, transmission of electricity and other operation services. Payments under these contracts for the years ended December 31, 2011, 2010 and 2009 were $1.8 billion, $1.7 billion and $2.8 billion, respectively.

The table below sets forth the future minimum commitments under these other purchase contracts as of December 31, 2011 for 2012 through 2016 and thereafter:

December 31,	Future Commitments for Other Purchase Contracts
	(in millions)
2012	$ 1,853
2013	1,476
2014	1,232
2015	990
2016	906
Thereafter	9,618
Total	$16,075

13. CONTINGENCIES

ENVIRONMENTAL LIABILITIES

The Company periodically reviews its obligations as they relate to compliance with environmental laws, including site restoration and remediation. As of December 31, 2011, the Company had recorded liabilities of $26 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 December 31, 2011.

GUARANTEES, LETTERS OF CREDIT

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 December 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 $24 million.

Contingent contractual obligations	Amount	Number of Agreements	Maximum Exposure Range for Each Agreement
	(in millions)		(in millions)
Guarantees	$351	22	<$1 - $53
Letters of credit under the senior secured credit facility	12	11	<$1 -$7
Cash collateralized letters of credit	261	13	<$1 - $221
Total	$624	46	

As of December 31, 2011, the Company had $9 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 2012. 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.

During 2011, the Company paid letter of credit fees ranging from 0.250% to 3.250% per annum on the outstanding amounts of letters of credit.

LITIGATION

The Company is involved in certain claims, suits and legal proceedings in the normal course of business. The Company accrues for litigation and claims when 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 $363 million and $443 million as of December 31, 2011 and 2010, respectively. These reserves are reported on the 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 consolidated financial statements. However, 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 December 31, 2011. The material contingencies where a loss is reasonably possible primarily include: claims under financing agreements; disputes with offtakers, suppliers and EPC contractors; alleged violation of monopoly laws and regulations; income tax and non-income tax assessments by tax authorities; and environmental matters. In aggregate, the Company estimates that the range of potential losses, where estimable, related to these material contingences to be in the range of $355 million to $1.7 billion. The amounts considered reasonably possible do not include amounts reserved, as discussed above. These material contingencies do not include income tax related contingencies which are considered part of our uncertain tax positions.

14. BENEFIT PLANS

DEFINED CONTRIBUTION PLAN—The Company sponsors one defined contribution plan ("the Plan"), qualified under section 401 of the Internal Revenue Code. All U.S. employees of the Company are eligible to participate in the Plan except for those employees who are covered by a collective bargaining agreement, unless such agreement specifically provides that the employee is considered an eligible employee under the Plan. The Plan provides matching contributions in AES common stock, other contributions at the discretion of the Compensation Committee of the Board of Directors in AES common stock and discretionary tax deferred contributions from the participants. Participants are fully vested in their own contributions and the Company's matching contributions. Participants vest in other company contributions ratably over a five-year period ending on the fifth anniversary of their hire date. Company contributions to the Plan were approximately $22 million for each of the years ended December 31, 2011, 2010, and 2009.

DEFINED BENEFIT PLANS—Certain of the Company's subsidiaries have defined benefit pension plans covering substantially all of their respective employees. Pension benefits are based on years of credited service, age of the participant and average earnings. Of the 26 active defined benefit plans as of December 31, 2011, four are at U.S. subsidiaries and the remaining plans are at foreign subsidiaries.

The following table reconciles the Company's funded status, both domestic and foreign, as of December 31, 2011 and 2010:

	December 31,			
	2011		2010	
	U.S.	Foreign	U.S.	Foreign
	(in millions)			
CHANGE IN PROJECTED BENEFIT OBLIGATION:				
Benefit obligation at beginning of year	$ 608	$ 5,986	$ 549	$ 5,129
Service cost	8	19	7	16
Interest cost	33	564	32	510
Employee contributions	—	5	—	5
Plan amendments	—	—	11	—
Plan curtailments	—	5	—	—
Plan settlements	—	—	—	(2)
Benefits paid	(30)	(465)	(30)	(409)
Business combinations	365	—	—	14
Actuarial loss	60	371	39	474
Effect of foreign currency exchange rate change	—	(696)	—	249
Benefit obligation as of December 31	$1,044	$ 5,789	$ 608	$ 5,986
CHANGE IN PLAN ASSETS:				
Fair value of plan assets at beginning of year	$ 413	$ 4,730	$ 368	$ 4,042
Actual return on plan assets	6	486	46	742
Employer contributions	37	175	29	156
Employee contributions	—	5	—	5
Plan settlements	—	—	—	(2)
Benefits paid	(30)	(465)	(30)	(409)
Business combinations	336	—	—	—
Effect of foreign currency exchange rate change	—	(531)	—	196
Fair value of plan assets as of December 31	$ 762	$ 4,400	$ 413	$ 4,730
RECONCILIATION OF FUNDED STATUS				
Funded status as of December 31	$ (282)	$(1,389)	$(195)	$(1,256)

The following table summarizes the amounts recognized on the Consolidated Balance Sheets related to the funded status of the plans, both domestic and foreign, as of December 31, 2011 and 2010:

	December 31,			
	2011		2010	
	U.S.	Foreign	U.S.	Foreign
	(in millions)			
AMOUNTS RECOGNIZED ON THE CONSOLIDATED BALANCE SHEETS				
Noncurrent assets	$ —	$ 20	$ —	$ 32
Accrued benefit liability—current	(1)	(4)	—	(4)
Accrued benefit liability—long-term	(281)	(1,405)	(195)	(1,284)
Net amount recognized at end of year	$(282)	$(1,389)	$(195)	$(1,256)

The following table summarizes the Company's accumulated benefit obligation, both domestic and foreign, as of December 31, 2011 and 2010:

	December 31,			
	2011		2010	
	U.S.	Foreign	U.S.	Foreign
	(in millions)			
Accumulated Benefit Obligation	$1,020	$5,724	$592	$5,927
Information for pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	$1,044	$5,478	$608	$5,697
Accumulated benefit obligation	1,020	5,423	592	5,651
Fair value of plan assets	762	4,072	413	4,410
Information for pension plans with a projected benefit obligation in excess of plan assets:				
Projected benefit obligation	$1,044	$5,492	$608	$5,704
Fair value of plan assets	762	4,084	413	4,415

The table below summarizes the significant weighted average assumptions used in the calculation of benefit obligation and net periodic benefit cost, both domestic and foreign, as of December 31, 2011 and 2010:

	December 31,			
	2011		2010	
	U.S.	Foreign	U.S.	Foreign
Benefit Obligation:				
Discount rates	4.67%	9.52%(2)	5.38%	9.82%(2)
Rates of compensation increase	3.94%(1)	5.98%	N/A(1)	5.99%
Periodic Benefit Cost:				
Discount rate	5.38%	9.82%	5.92%	10.56%
Expected long-term rate of return on plan assets	7.49%	11.08%	8.00%	11.14%
Rate of compensation increase	3.94%(1)	5.98%	N/A(1)	5.99%

(1) A U.S. subsidiary of the Company has a defined benefit obligation of $679 million and $607 million as of December 31, 2011 and 2010, respectively, and uses salary bands to determine future benefit costs rather than rates of compensation increases. Rates of compensation increases in the table above do not include amounts related to this specific defined benefit plan.

(2) Includes an inflation factor that is used to calculate future periodic benefit cost, but is not used to calculate the benefit obligation.

The Company establishes its estimated long-term return on plan assets considering various factors, which include the targeted asset allocation percentages, historic returns and expected future returns.

The measurement of pension obligations, costs and liabilities is dependent on a variety of assumptions. These assumptions include estimates of the present value of projected future pension payments to all plan participants, taking into consideration the likelihood of potential future events such as salary increases and demographic experience. These assumptions may have an effect on the amount and timing of future contributions.

The assumptions used in developing the required estimates include the following key factors:

- discount rates;

- salary growth;
- retirement rates;
- inflation;
- expected return on plan assets; and
- mortality rates.

The effects of actual results differing from the Company's assumptions are accumulated and amortized over future periods and, therefore, generally affect the Company's recognized expense in such future periods.

Sensitivity of the Company's pension funded status to the indicated increase or decrease in the discount rate and long-term rate of return on plan assets assumptions is shown below. Note that these sensitivities may be asymmetric and are specific to the base conditions at year-end 2011. They also may not be additive, so the impact of changing multiple factors simultaneously cannot be calculated by combining the individual sensitivities shown. The December 31, 2011 funded status is affected by the December 31, 2011 assumptions. Pension expense for 2011 is affected by the December 31, 2010 assumptions. The impact on pension expense from a one percentage point change in these assumptions is shown in the table below (in millions):

Increase of 1% in the discount rate	$(40)
Decrease of 1% in the discount rate	$ 42
Increase of 1% in the long-term rate of return on plan assets	$(51)
Decrease of 1% in the long-term rate of return on plan assets	$ 51

The following table summarizes the components of the net periodic benefit cost, both domestic and foreign, for the years ended December 31, 2011 through 2009:

	December 31,					
	2011		2010		2009	
Components of Net Periodic Benefit Cost:	U.S.	Foreign	U.S.	Foreign	U.S.	Foreign
			(in millions)			
Service cost	$ 8	$ 19	$ 7	$ 16	$ 6	$ 12
Interest cost	33	564	32	510	32	458
Expected return on plan assets	(33)	(508)	(30)	(427)	(24)	(373)
Amortization of initial net asset	—	—	—	(1)	—	(2)
Amortization of prior service cost	4	—	3	—	4	—
Amortization of net loss	13	23	12	38	16	6
Loss on curtailment	—	5	—	—	—	—
Settlement gain recognized	—	—	—	1	—	—
Total pension cost	$ 25	$ 103	$ 24	$ 137	$ 34	$ 101

The following table summarizes the amounts reflected in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheet as of December 31, 2011 that have not yet been recognized as components of net periodic benefit cost:

	December 31, 2011			
	Accumulated Other Comprehensive Loss		Amounts expected to be reclassified to earnings in next fiscal year	
	U.S.	Foreign	U.S.	Foreign
	(in millions)			
Prior service cost	$—	$ (2)	$—	$—
Unrecognized net actuarial loss	—	(1,112)	—	(40)
Total	$—	$(1,114)	$—	$ (40)

The following table summarizes the Company's target allocation for 2011 and pension plan asset allocation, both domestic and foreign, as of December 31, 2011 and 2010:

	Target Allocations		Percentage of Plan Assets as of December 31,			
			2011		2010	
Asset Category	U.S.	Foreign	U.S.	Foreign	U.S.	Foreign
Equity securities	46%	15% - 30%	42.07%	23.48%	53.51%	22.43%
Debt securities	39%	59% - 85%	38.53%	72.55%	25.91%	73.64%
Real estate	0%	0% - 4%	0.00%	2.34%	0.00%	2.09%
Other	15%	0% - 6%	19.40%	1.63%	20.58%	1.84%
Total pension assets			100.00%	100.00%	100.00%	100.00%

The U.S. plans seek to achieve the following long-term investment objectives:

- maintenance of sufficient income and liquidity to pay retirement benefits and other lump sum payments;
- long-term rate of return in excess of the annualized inflation rate;
- long-term rate of return, net of relevant fees, that meet or exceed the assumed actuarial rate; and
- long-term competitive rate of return on investments, net of expenses, that is equal to or exceeds various benchmark rates.

The asset allocation is reviewed periodically to determine a suitable asset allocation which seeks to manage risk through portfolio diversification and takes into account, among other possible factors, the above-stated objectives, in conjunction with current funding levels, cash flow conditions and economic and industry trends. The following table summarizes the Company's U.S. plan assets by category of investment and level within the fair value hierarchy as of December 31, 2011 and 2010:

U.S. Plans	December 31, 2011 Level 1	Level 2	Level 3	Total	December 31, 2010 Level 1	Level 2	Level 3	Total
				(in millions)				
Equity securities:								
Common stock	$120	$—	$—	$120	$146	$—	$—	$146
Mutual funds	140	—	—	140	39	—	—	39
Debt securities:								
Government debt securities	31	—	—	31	32	—	—	32
Corporate debt securities	114	—	—	114	62	—	—	62
Mutual funds[(1)]	135	—	—	135	2	—	—	2
Other debt securities	14	—	—	14	11	—	—	11
Other:								
Cash and cash equivalents	43	—	—	43	69	—	—	69
Other investments	72	93	—	165	—	52	—	52
Total plan assets	$669	$ 93	$—	$762	$361	$ 52	$—	$413

(1) Mutual funds categorized as debt securities consist of mutual funds for which debt securities are the primary underlying investment.

The investment strategy of the foreign plans seeks to maximize return on investment while minimizing risk. The assumed asset allocation has less exposure to equities in order to closely match market conditions and near term forecasts. The following table summarizes the Company's foreign plan assets by category of investment and level within the fair value hierarchy as of December 31, 2011 and 2010:

Foreign Plans	December 31, 2011 Level 1	Level 2	Level 3	Total	December 31, 2010 Level 1	Level 2	Level 3	Total
				(in millions)				
Equity securities:								
Common stock	$ 26	$ —	$—	$ 26	$ 30	$ —	$—	$ 30
Mutual funds	427	—	—	427	510	—	—	510
Private equity[(1)]	—	—	580	580	—	—	521	521
Debt securities:								
Certificates of deposit	—	5	—	5	—	4	—	4
Unsecured debentures	—	20	—	20	—	19	—	19
Government debt securities	6	221	—	227	—	233	—	233
Mutual funds[(2)]	125	2,805	—	2,930	108	3,107	—	3,215
Other debt securities	—	10	—	10	—	12	—	12
Real estate:								
Real estate[(1)]	—	—	103	103	—	—	99	99
Other:								
Cash and cash equivalents	—	—	—	—	—	4	—	4
Participant loans[(3)]	—	—	72	72	—	—	83	83
Total plan assets	$584	$3,061	$755	$4,400	$648	$3,379	$703	$4,730

(1) Plan assets of our Brazilian subsidiaries are invested in private equities and commercial real estate through the plan administrator in Brazil. The fair value of these assets is determined using the income approach through annual appraisals based on a discounted cash flow analysis.
(2) Mutual funds categorized as debt securities consist of mutual funds for which debt securities are the primary underlying investment.
(3) Loans to participants are stated at cost, which approximates fair value.

The following table presents a reconciliation of all plan assets measured at fair value using significant unobservable inputs (Level 3) for the years ended December 31, 2011 and 2010:

	Year Ended December 31,	
	2011	2010
	(in millions)	
Balance at January 1	$703	$564
Actual return on plan assets:		
Returns relating to assets still held at reporting date	167	104
Returns relating to assets sold during the period	28	—
Purchases, sales and settlements, net	(48)	3
Change due to exchange rate changes	(95)	32
Balance at December 31	$755	$703

The following table summarizes the scheduled cash flows for U.S. and foreign expected employer contributions and expected future benefit payments, both domestic and foreign:

	U.S.	Foreign
	(in millions)	
Expected employer contribution in 2012	$ 49	$ 174
Expected benefit payments for fiscal year ending:		
2012	55	421
2013	56	435
2014	58	451
2015	59	465
2016	61	483
2017 - 2021	325	2,657

15. EQUITY

STOCK PURCHASE AGREEMENT

On March 12, 2010, the Company and Terrific Investment Corporation ("Investor"), a wholly owned subsidiary of China Investment Corporation, entered into a stockholder agreement (the "Stockholder Agreement") in connection with the agreement discussed in the following paragraph. Under the Stockholder Agreement, as long as Investor holds more than 5% of the outstanding shares of common stock of the Company, Investor has the right to designate one nominee, who must be reasonably acceptable to the Board, for election to the Board of Directors of the Company. Effective December 9, 2011, Investor's designated nominee was elected to the Board of Directors of the Company. In addition, until such time as Investor holds 5% or less of the outstanding shares of common stock, Investor has agreed to vote its shares in accordance with the recommendation of the Company on any matters submitted to a vote of the stockholders of the Company relating to the election of directors and compensation matters. Otherwise, Investor may vote its shares at its discretion. Further, under the Stockholder Agreement, Investor will be subject to a standstill restriction which generally prohibits Investor from purchasing additional securities of the Company beyond the level acquired by it under the stock purchase agreement entered into between Investor and the Company on November 6, 2009. The standstill and lock-up restrictions also terminate at such time as Investor holds 5% or less of the outstanding shares of common stock. Investor has certain registration rights and preemptive rights under the Stockholder Agreement with respect to its shares of common stock of the Company.

On March 15, 2010, the Company completed the sale of 125,468,788 shares of common stock to Investor. The shares were sold for $12.60 per share, for an aggregate purchase price of $1.58 billion. Investor's ownership in the Company's common stock is now approximately 15% of the Company's total outstanding shares of common stock on a fully diluted basis.

STOCK REPURCHASE PROGRAM

In July 2010, the Company's Board of Directors approved a stock repurchase program (the "Program") under which the Company can 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. There can be no assurances as to the amount, timing or prices of repurchases, which may vary based on market conditions and other factors. The Program does not have an expiration date and can be modified or terminated by the Board of Directors at any time. During the year ended December 31, 2011, shares of common stock repurchased under this plan totaled 25,541,980 at a total cost of $279 million plus a nominal amount of commissions (average of $10.93 per share including commissions), bringing the cumulative total purchases under the program to 33,924,805 shares at a total cost of $378 million plus a nominal amount of commissions (average of $11.16 per share including commissions).

The shares of stock repurchased have been classified as treasury stock and accounted for using the cost method. A total of 42,386,961 and 17,287,073 shares were held in treasury stock at December 31, 2011 and 2010, respectively. The Company has not retired any shares held in treasury during the years ended December 31, 2011, 2010 or 2009.

COMPREHENSIVE INCOME

The components of comprehensive income for the years ended December 31, 2011, 2010 and 2009 were as follows:

	December 31,		
	2011	2010	2009
		(in millions)	
Net income	$ 1,530	$ 1,059	$ 1,755
Available-for-sale securities activity:			
Change in fair value of available-for-sale securities, net of income tax (expense) benefit of $0, $3 and $(4), respectively	1	(5)	8
Reclassification to earnings, net of income tax (expense) benefit of $0, $0 and $0, respectively	(2)	—	(2)
Total change in fair value of available-for-sale securities	(1)	(5)	6
Foreign currency activity:			
Foreign currency translation adjustments, net of income tax (expense) benefit of $18, $(11) and $(78), respectively	(484)	468	746
Reclassification to earnings, net of income tax (expense) benefit of $0, $0 and $0, respectively	188	142	(4)
Total foreign currency translation adjustments	(296)	610	742
Derivative activity:			
Change in derivative fair value, net of income tax (expense) benefit of $108, $56 and $34, respectively	(379)	(242)	214
Reclassification to earnings, net of income tax (expense) benefit of $(22), $(41) and $(41), respectively	137	162	(141)
Total change in fair value of derivatives	(242)	(80)	73
Pension activity:			
Change in unfunded pension obligation, net of income tax (expense) benefit of $117, $57 and $70, respectively	(223)	(111)	(139)
Reclassification to earnings, net of income tax (expense) benefit of $(6), $(12) and $(1), respectively	13	23	—
Total change in unfunded pensions obligation	(210)	(88)	(139)
Other comprehensive income (loss)	(749)	437	682
Comprehensive income	781	1,496	2,437
Less: Comprehensive income attributable to noncontrolling interests[1]	(1,098)	(1,108)	(1,485)
Comprehensive income (loss) attributable to The AES Corporation	$ (317)	$ 388	$ 952

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

The following table summarizes the balances comprising accumulated other comprehensive loss, net of tax, as of December 31, 2011 and 2010:

	December 31, 2011	December 31, 2010
	(in millions)	
Foreign currency translation adjustment	$1,967	$1,824
Unrealized derivative losses, net	534	344
Unfunded pension obligations	257	216
Unrealized (gain) loss on securities available for sale	—	(1)
Total	$2,758	$2,383

EQUITY TRANSACTIONS WITH NONCONTROLLING INTERESTS

On July 7, 2011, a subsidiary of the Company completed the acquisition of an additional 10% equity interest in AES-VCM Mong Duong Power Company Limited ("Mong Duong"), a 1,200 MW coal-fired power plant in development in the Quang Ninh province in Vietnam, from Vietnam National Coal and Mineral Industries Group, its minority shareholder. On July 8, 2011, through a subsidiary, the Company sold 30% and 19% equity interests in Mong Duong to PSC Energy Global Co., Ltd. (a wholly owned subsidiary of POSCO Corporation) and Stable Investment Corporation (a wholly owned subsidiary of China Investment Corporation, a related party), respectively, resulting in the Company retaining a 51% indirect equity interest in Mong Duong. As a result of these transactions, the Company did not lose control of Mong Duong, which continues to be accounted for as a consolidated subsidiary. A net gain of $19 million resulting from these transactions was recorded as an equity transaction in additional paid-in capital.

The following table summarizes the net income attributable to The AES Corporation and transfers (to) from noncontrolling interests for the years ended December 31, 2011 and 2010:

	December 31, 2011	December 31, 2010
	(in millions)	
Net income attributable to The AES Corporation	$ 58	$ 9
Transfers (to) from the noncontrolling interests:		
Net increase in The AES Corporation's paid-in capital for sale of subsidiary shares	19	—
Decrease in The AES Corporation's paid-in capital for purchase of subsidiary shares	—	(25)
Net transfers (to) from noncontrolling interest	19	(25)
Change from net income attributable to The AES Corporation and transfers (to) from noncontrolling interests	$ 77	$ (16)

16. SEGMENT AND GEOGRAPHIC INFORMATION

The Company's current 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"). The segment reporting structure uses the Company's management reporting structure as its foundation to reflect how the Company manages the business internally. In October 2011, the Company announced a plan to redefine its operational management and organizational structure. The reporting structure will remain organized along two lines of business – Generation and Utilities, each led by a Chief Operating Officer, however, we are continuing to evaluate both the timing and impact, if any, that the realignment will have on our reportable segments. For the year ended December 31, 2011 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 operating segments and climate solutions and other renewables projects 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 management fees and 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 December 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 as of and for the years ended December 31, 2011 through 2009:

	Total Revenue			Intersegment			External Revenue		
	2011	2010	2009	2011	2010	2009	2011	2010	2009
	(in millions)								
Revenue									
Latin America—Generation	$ 4,982	$ 4,281	$ 3,651	$(1,148)	$(1,017)	$(864)	$ 3,834	$ 3,264	$ 2,787
Latin America—Utilities	7,374	6,987	5,877	—	—	—	7,374	6,987	5,877
North America—Generation	1,465	1,453	1,381	(4)	—	—	1,461	1,453	1,381
North America—Utilities	1,326	1,145	1,068	—	—	—	1,326	1,145	1,068
Europe—Generation	1,550	1,318	762	(2)	(2)	2	1,548	1,316	764
Asia—Generation	625	618	375	—	—	—	625	618	375
Corp/Other and eliminations	(48)	26	(4)	1,154	1,019	862	1,106	1,045	858
Total Revenue	$17,274	$15,828	$13,110	$ —	$ —	$ —	$17,274	$15,828	$13,110

	Total Adjusted Gross Margin			Intersegment			External Adjusted Gross Margin		
	2011	2010	2009	2011	2010	2009	2011	2010	2009
	(in millions)								
Adjusted Gross Margin									
Latin America—Generation	$2,086	$1,698	$1,528	$(1,090)	$(1,010)	$(852)	$ 996	$ 688	$ 676
Latin America—Utilities	1,321	1,248	1,060	1,118	1,018	865	2,439	2,266	1,925
North America—Generation	533	540	537	9	2	(3)	542	542	534
North America—Utilities	394	407	401	1	2	2	395	409	403
Europe—Generation	469	395	273	8	3	4	477	398	277
Asia—Generation	176	255	111	2	2	4	178	257	115
Corp/Other and eliminations	(27)	65	16	(48)	(17)	(20)	(75)	48	(4)
Reconciliation to Income from Continuing Operations before Taxes									
Depreciation and amortization							(1,209)	(1,064)	(908)
Interest expense							(1,603)	(1,503)	(1,461)
Interest income							400	408	344
Other expense							(156)	(234)	(104)
Other income							149	100	459
Gain on sale of investments							8	—	131
Goodwill impairment							(17)	(21)	(122)
Asset impairment expense							(225)	(389)	(20)
Foreign currency transaction gains (losses)							(38)	(33)	35
Other non-operating expense							(82)	(7)	(12)
Income from continuing operations before taxes and equity in earnings of affiliates							$ 2,179	$ 1,865	$ 2,268

	Total Assets			Depreciation and Amortization			Capital Expenditures		
	2011	2010	2009	2011	2010	2009	2011	2010	2009
	(in millions)								
Latin America—Generation	$10,713	$10,373	$ 9,802	$ 261	$ 215	$ 183	$ 658	$ 641	$ 951
Latin America—Utilities	9,468	9,609	8,810	293	231	201	666	584	356
North America—Generation	4,326	4,519	4,914	150	160	158	64	71	64
North America—Utilities	9,384	3,139	3,035	178	161	157	232	177	116
Europe—Generation	3,276	3,317	3,147	136	114	53	140	233	212
Asia—Generation	1,717	1,762	1,594	33	33	32	129	10	22
Discontinued businesses	829	1,844	3,023	27	81	117	66	88	100
Corp/Other and eliminations	5,620	5,948	5,210	184	183	148	506	529	717
Total	$45,333	$40,511	$39,535	$1,262	$1,178	$1,049	$2,461	$2,333	$2,538

	Investment in and Advances to Affiliates			Equity in Earnings (Loss)		
	2011	2010	2009	2011	2010	2009
	(in millions)					
Latin America—Generation	$ 188	$ 150	$ 129	$ 35	$ 48	$ 30
Latin America—Utilities	—	—	—	—	—	—
North America—Generation	18	—	3	(2)	(2)	(2)
North America—Utilities	—	—	—	—	—	—
Europe—Generation	479	353	308	8	19	50
Asia—Generation	291	409	390	(1)	3	28
Discontinued businesses	—	—	—	—	—	—
Corp/Other and eliminations	446	408	327	(42)	116	(13)
Total	$1,422	$1,320	$1,157	$ (2)	$184	$ 93

The table below presents information, by country, about the Company's consolidated operations for each of the years ended December 31, 2011 through 2009 and as of December 31, 2011 and 2010, respectively. Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located.

	Revenue			Property, Plant & Equipment, net	
	2011	2010	2009	2011	2010
			(in millions)		
United States[1]	$ 2,256	$ 2,095	$ 1,987	$ 8,448	$ 6,027
Non-U.S.:					
Brazil[2]	6,640	6,355	5,292	5,896	6,263
Chile	1,608	1,355	1,239	2,781	2,560
Argentina[3]	979	771	571	279	270
El Salvador	752	648	619	268	261
Dominican Republic	674	535	429	662	625
United Kingdom[4]	587	364	228	523	507
Philippines	480	501	250	766	784
Ukraine	418	356	286	94	86
Mexico	404	409	329	774	786
Cameroon	386	422	370	901	823
Colombia	365	393	347	384	387
Puerto Rico	298	253	267	581	596
Spain[5]	258	411	—	—	—
Bulgaria[6]	251	44	—	1,619	1,825
Hungary[7]	204	252	259	6	73
Panama	189	194	168	1,040	921
Kazakhstan	145	138	123	86	63
Sri Lanka	140	100	109	22	69
Jordan	124	120	104	216	224
Qatar[8]	—	—	—	—	—
Pakistan[9]	—	—	—	—	—
Oman[10]	—	—	—	—	—
Other Non-U.S. [11]	116	112	133	385	279
Total Non-U.S.	15,018	13,733	11,123	17,283	17,402
Total	$17,274	$15,828	$13,110	$25,731	$23,429

(1) Excludes revenue of $228 million, $519 million and $559 million for the years ended December 31, 2011, 2010 and 2009, respectively, and property, plant and equipment of $140 million as of December 31, 2010, related to Eastern Energy and Thames, which were reflected as discontinued operations and businesses held for sale in the accompanying Consolidated Statements of Operations and Consolidated Balance Sheets.

(2) Excludes revenue of $124 million, $118 million and $102 million for the years ended December 31, 2011, 2010 and 2009, respectively, and property, plant and equipment of $151 million as of December 31, 2010, related to Brazil Telecom, which was reflected as discontinued operations and businesses held for sale in the accompanying Consolidated Statements of Operations and Consolidated Balance Sheets.

(3) Excludes revenue of $102 million, $116 million and $113 million for the years ended December 31, 2011, 2010 and 2009, respectively, and property, plant and equipment of $189 million as of December 31, 2010, related to our Argentina distribution businesses, which were reflected as discontinued operations and businesses held for sale in the accompanying Consolidated Statements of Operations and Consolidated Balance Sheets.

(4) Excludes revenue of $17 million, $21 million and $11 million for the years ended December 31, 2011, 2010 and 2009, respectively, and property, plant and equipment of $20 million as of December 31, 2010, related to carbon reduction projects, which were reflected as discontinued operations and businesses held for sale in the accompanying Consolidated Statements of Operations and Consolidated Balance Sheets.

(5) Excludes property, plant and equipment of $620 million and $667 million as of December 31, 2011 and 2010, respectively, related to Cartagena, which was reflected as businesses held for sale in the accompanying Consolidated Balance Sheets.

(6) Maritza and our wind project in Bulgaria were under development and therefore not operational as of December 31, 2009. Our wind project in Bulgaria started operations in 2010 and Maritza started operations in June 2011.

(7) Excludes revenue of $14 million, $44 million and $58 million for the years ended December 31, 2011, 2010 and 2009, respectively, and property, plant and equipment of $7 million as of December 31, 2010, related to Borsod and Tiszapalkonya, which were reflected as discontinued operations and businesses held for sale in the accompanying Consolidated Statements of Operations and Consolidated Balance Sheets.

(8) Excludes revenue of $129 million and $163 million for the years ended December 31, 2010 and 2009, respectively, related to Ras Laffan, which was reflected as discontinued operations and businesses held for sale in the accompanying Consolidated Statements of Operations.

(9) Excludes revenue of $299 million and $470 million for the years ended December 31, 2010 and 2009, respectively, related to Lal Pir and Pak Gen, which were reflected as discontinued operations and businesses held for sale in the accompanying Consolidated Statements of Operations.

(10) Excludes revenue of $62 million and $101 million for the years ended December 31, 2010 and 2009, respectively, related to Barka, which was reflected as discontinued operations and businesses held for sale in the accompanying Consolidated Statements of Operations.

(11) Excludes revenue of $1 million for the year ended December 31, 2011, and property, plant and equipment of $2 million and $18 million as of December 31, 2011, and 2010, respectively, related to alternative energy and carbon reduction projects, which were reflected as discontinued operations and businesses held for sale in the accompanying Consolidated Statements of Operations and Consolidated Balance Sheets.

17. SHARE-BASED COMPENSATION

STOCK OPTIONS—AES grants options to purchase shares of common stock under stock option plans. Under the terms of the plans, the Company may issue options to purchase shares of the Company's common stock at a price equal to 100% of the market price at the date the option is granted. Stock options are generally granted based upon a percentage of an employee's base salary. Stock options issued under these plans in 2011, 2010 and 2009 have a three-year vesting schedule and vest in one-third increments over the three-year period. The stock options have a contractual term of ten years. At December 31, 2011, approximately 17 million shares were remaining for award under the plans. In all circumstances, stock options granted by AES do not entitle the holder the right, or obligate AES, to settle the stock option in cash or other assets of AES.

The weighted average fair value of each option grant has been estimated, as of the grant date, using the Black-Scholes option-pricing model with the following weighted average assumptions:

	December 31,		
	2011	2010	2009
Expected volatility	31%	38%	66%
Expected annual dividend yield	0%	0%	0%
Expected option term (years)	6	6	6
Risk-free interest rate	2.65%	2.86%	2.01%

The Company exclusively relies on implied volatility as the expected volatility to determine the fair value using the Black-Scholes option-pricing model. The implied volatility may be exclusively relied upon due to the following factors:

- The Company utilizes a valuation model that is based on a constant volatility assumption to value its employee share options;
- The implied volatility is derived from options to purchase AES common stock that are actively traded;
- The market prices of both the traded options and the underlying shares are measured at a similar point in time and on a date reasonably close to the grant date of the employee share options;
- The traded options have exercise prices that are both near-the-money and close to the exercise price of the employee share options; and
- The remaining maturities of the traded options on which the estimate is based are at least one year.

Pursuant to share-based compensation accounting guidance, the Company used a simplified method to determine the expected term based on the average of the original contractual term and the pro rata vesting period. This simplified method was used for stock options granted during 2011, 2010 and 2009. This is appropriate given a lack of relevant stock option exercise data. This simplified method may be used as the Company's stock options have the following characteristics:

- The stock options are granted at-the-money;
- Exercisability is conditional only on performing service through the vesting date;
- If an employee terminates service prior to vesting, the employee forfeits the stock options;
- If an employee terminates service after vesting, the employee has a limited time to exercise the stock option; and
- The stock option is nonhedgeable and not transferable.

The Company does not discount the grant date fair values to estimate post-vesting restrictions. Post-vesting restrictions include black-out periods when the employee is not able to exercise stock options based on their potential knowledge of information prior to the release of that information to the public.

Using the above assumptions, the weighted average fair value of each stock option granted was $4.54, $5.08 and $4.08, for the years ended December 31, 2011, 2010, and 2009, respectively.

The following table summarizes the components of stock-based compensation related to employee stock options recognized in the Company's financial statements:

	December 31,		
	2011	2010	2009
	(in millions)		
Pre-tax compensation expense	$ 7	$ 9	$10
Tax benefit	(2)	(2)	(3)
Stock options expense, net of tax	$ 5	$ 7	$ 7
Total intrinsic value of options exercised	$ 8	$ 2	$ 3
Total fair value of options vested	7	11	13
Cash received from the exercise of stock options	4	2	6

There was no cash used to settle stock options or compensation cost capitalized as part of the cost of an asset for the years ended December 31, 2011, 2010 and 2009. As of December 31, 2011, $3 million of total unrecognized compensation cost related to stock options is expected to be recognized over a weighted average period of 1.8 years. During the year ended December 31, 2011, modifications were made to stock option awards affecting 2 million stock options.

A summary of the option activity for the year ended December 31, 2011 follows (number of options in thousands, dollars in millions except per option amounts):

	Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value
Outstanding at December 31, 2010	20,482	$16.04		
Exercised	(958)	4.21		
Forfeited and expired	(11,197)	17.72		
Granted	1,131	12.60		
Outstanding at December 31, 2011	9,458	$13.82	4.8	$17
Vested and expected to vest at December 31, 2011	9,379	$13.84	4.7	$16
Eligible for exercise at December 31, 2011	7,385	$14.58	4.1	$14

The aggregate intrinsic value in the table above represents the total pre-tax intrinsic value (the difference between the Company's closing stock price on the last trading day of the fourth quarter of 2011 and the exercise price, multiplied by the number of in-the-money options) that would have been received by the option holders had all option holders exercised their options on December 31, 2011. The amount of the aggregate intrinsic value will change based on the fair market value of the Company's stock.

The Company initially recognizes compensation cost on the estimated number of instruments for which the requisite service is expected to be rendered. In 2011, AES has estimated a forfeiture rate of 12.81% for stock options granted in 2011. This estimate will be revised if subsequent information indicates that the actual number of instruments forfeited is likely to differ from previous estimates. Based on the estimated forfeiture rate, the Company expects to expense $4.4 million on a straight-line basis over a three year period (approximately $1.5 million per year) related to stock options granted during the year ended December 31, 2011.

RESTRICTED STOCK

Restricted Stock Units Without Market Conditions—The Company issues restricted stock units ("RSUs") without market conditions under its long-term compensation plan. The RSUs are generally granted based upon a percentage of the participant's base salary. The units have a three-year vesting schedule and vest in one-third increments over the three-year period. Units granted prior to 2011 are required to be held for an additional two years before they can be converted into shares, and thus become transferable. There is no such requirement for units granted in 2011. In all circumstances, restricted stock units granted by AES do not entitle the holder the right, or obligate AES, to settle the restricted stock unit in cash or other assets of AES.

For the years ended December 31, 2011, 2010, and 2009, RSUs issued without a market condition had a grant date fair value equal to the closing price of the Company's stock on the grant date. The Company does not discount the grant date fair values to reflect any post-vesting restrictions. RSUs without a market condition granted to employees during the years ended December 31, 2011, 2010, and 2009 had grant date fair values per RSU of $12.65, $12.18 and $6.71, respectively. The total grant date fair value of RSUs granted in 2011 without a market condition was $20 million.

The following table summarizes the components of the Company's stock-based compensation related to its employee RSUs issued without market conditions recognized in the Company's consolidated financial statements:

	December 31,		
	2011	2010	2009
	(in millions)		
RSU expense before income tax	$11	$11	$11
Tax benefit	(3)	(2)	(3)
RSU expense, net of tax	$ 8	$ 9	$ 8
Total value of RSUs converted[(1)]	$ 5	$ 5	$ 7
Total fair value of RSUs vested	$10	$12	$12

(1) Amount represents fair market value on the date of conversion.

There was no cash used to settle RSUs or compensation cost capitalized as part of the cost of an asset for the years ended December 31, 2011, 2010 and 2009. As of December 31, 2011, $14 million of total unrecognized compensation cost related to RSUs without a market condition is expected to be recognized over a weighted average period of approximately 1.9 years. There were no modifications to RSU awards during the year ended December 31, 2011.

A summary of the activity of RSUs without a market condition for the year ended December 31, 2011 follows (number of RSUs in thousands):

	RSUs	Weighted Average Grant Date Fair Values	Weighted Average Remaining Vesting Term
Nonvested at December 31, 2010	2,167	$10.20	
Vested	(982)	10.91	
Forfeited and expired	(395)	12.16	
Granted	1,565	12.65	
Nonvested at December 31, 2011	2,355	$11.40	1.6
Vested at December 31, 2011	2,620	$13.97	
Vested and expected to vest at December 31, 2011	4,788	$12.77	

The table below summarizes the RSUs without a market condition that vested and were converted during the years ended December 31, 2011, 2010 and 2009 (number of RSUs in thousands):

	December 31,		
	2011	2010	2009
RSUs vested during the year	982	929	619
RSUs converted during the year[(1)]	442	386	772

(1) Net of shares withheld for taxes of 150,000, 127,000 and 238,000 in the years ended December 31, 2011, 2010 and 2009, respectively.

Restricted Stock Units With Market and Performance Conditions—Restricted stock units were issued to officers of the Company during 2011 that contain market and performance conditions. 50% percent of the RSUs contained in the award include a market condition and the remaining 50% include a performance condition. Vesting will occur if the applicable continued employment conditions are satisfied and (a) for the units subject to the market condition the Total Stockholder Return ("TSR") on AES common stock exceeds the TSR of the Standard and Poor's 500 ("S&P 500") over the three-year measurement period beginning on January 1, 2011 and ending on December 31, 2013 and (b) for the units subject to the performance condition if the actual Cash Value Added ("CVA") meets the performance target over the three-year measurement period of beginning on January 1, 2011 and ending on December 31, 2013. In all circumstances, restricted stock units granted by AES do not entitle the holder the right, or obligate AES, to settle the restricted stock unit in cash or other assets of AES.

Restricted stock units with a market condition were awarded to officers of the Company in previous years and contained only the market condition measuring the TSR on AES common stock. These units were required to be held for an additional two years subsequent to vesting before they could be converted into shares and become transferable. There is no such requirement for the shares granted during 2011.

The effect of the market condition on restricted stock units issued to officers of the Company is reflected in the award's fair value on the grant date for the year ended December 31, 2011. A factor of 137% was applied to the closing price of the Company's stock on the date of grant to estimate the fair value to reflect the market condition for the portion of RSUs with market conditions granted during the year ended December 31, 2011. RSUs that included a market condition granted during the year ended December 31, 2011, 2010 and 2009 had a grant date fair value per RSU of $17.68, $11.57 and $6.68, respectively. The fair value of the RSUs with a performance condition had a grant date fair value of $12.88 equal to the closing price of the Company's stock on the grant date. The Company believes that it is probable that the performance condition will be met. This will continue to be evaluated throughout the performance period. The total grant date fair value of RSUs with market and performance conditions granted in 2011 was $12 million. If the factor was not applied to reflect the market condition for RSUs issued to officers, the total grant date fair value of RSUs with a market condition granted during the year ended December 31, 2011 would have decreased by $2 million.

The following table summarizes the components of the Company's stock-based compensation related to its RSUs granted with market and performance conditions recognized in the Company's consolidated financial statements:

	December 31,		
	2011	2010	2009
	(in millions)		
RSU expense before income tax	$ 5	$ 4	$ 4
Tax benefit	(1)	(1)	(1)
RSU expense, net of tax	$ 4	$ 3	$ 3
Total value of RSUs converted[1]	$—	$ 3	$ 4
Total fair value of RSUs vested[2]	$—	$—	$—

(1) Amount represents fair market value on the date of conversion.

(2) RSUs granted in 2008 with a market condition did not vest in 2011 because the TSR on AES common stock did not exceed the TSR of the S&P 500 over the three year vesting period.

There was no cash used to settle RSUs or compensation cost capitalized as part of the cost of an asset for the years ended December 31, 2011, 2010 and 2009. As of December 31, 2011, $6 million of total unrecognized compensation cost related to RSUs with market and performance conditions is expected to be recognized over a weighted average period of approximately 2.0 years. There were no modifications to RSU awards during the year ended December 31, 2011.

A summary of the activity of RSUs with market and performance conditions for the year ended December 31, 2011 follows (number of RSUs in thousands):

	RSUs	Weighted Average Grant Date Fair Values	Weighted Average Remaining Vesting Term
Nonvested at December 31, 2010	1,283	$ 9.80	
Vested	—	—	
Forfeited and expired	(693)	13.94	
Granted	767	15.28	
Nonvested at December 31, 2011	1,357	$10.78	1.1
Vested at December 31, 2011	—	$ —	
Vested and expected to vest at December 31, 2011	1,268	$10.55	

The table below summarizes the RSUs with market and performance conditions that vested and were converted during the years ended 2011, 2010 and 2009 (number of RSUs in thousands):

	December 31,		
	2011	2010	2009
RSUs vested during the year	—	—	—
RSUs converted during the year[(1)]	—	245	410

(1) Net of shares withheld for taxes of 0, 102,000 and 153,000 during the years ended December 31, 2011, 2010 and 2009, respectively.

18. SUBSIDIARY STOCK

Subsidiaries of the Company held cumulative preferred stock of $78 million and $60 million at December 31, 2011 and 2010, respectively, consisting of preferred stock held by IPL and DPL.

IPL, the Company's integrated utility in Indiana, had $60 million of cumulative preferred stock outstanding at December 31, 2011 and 2010, which represented five series of preferred stock. The total annual dividend requirements were approximately $3 million at December 31, 2011 and 2010. Certain series of the preferred stock were redeemable solely at the option of the issuer at prices between $100 and $118 per share. Holders of the preferred stock are entitled to elect a majority of IPL's board of directors if IPL has not paid dividends to its preferred stockholders for four consecutive quarters. Based on the preferred stockholders' ability to elect a majority of IPL's board of directors in this circumstance, the redemption of the preferred shares is considered to be not solely within the control of the issuer and the preferred stock is considered temporary equity and presented in the mezzanine level of the Consolidated Balance Sheets in accordance with the relevant accounting guidance for noncontrolling interests and redeemable securities.

DPL, the Company's newly acquired utility in Ohio, had $18 million of cumulative preferred stock outstanding at December 31, 2011, which represented three series of preferred stock issued by DP&L, a wholly owned subsidiary of DPL. The total annual dividend requirements were approximately $1 million at December 31, 2011. The DP&L preferred stock may be redeemed at DP&L's option as determined by its board of directors at per-share redemption prices between $101 and $103 per share, plus cumulative preferred dividends. In addition, DP&L's Amended Articles of Incorporation contain provisions that permit preferred stockholders to elect members of the DP&L Board of Directors in the event that cumulative dividends on the preferred stock are in arrears in an aggregate amount equivalent to at least four full quarterly dividends. Based on the preferred stockholders' ability to elect members of DP&L's board of directors in this circumstance, the redemption of the preferred shares is considered to be not solely within the control of the issuer and the preferred stock is considered temporary equity and presented in the mezzanine level of the Consolidated Balance Sheets in accordance with the relevant accounting guidance for noncontrolling interests and redeemable securities.

In February 2009, in connection with a preemptive rights period associated with a share issuance (capital increase) at AES Gener, Inversiones Cachagua Limitada ("Cachagua"), a wholly owned subsidiary of the Company, paid $175 million to AES Gener to maintain its current ownership percentage of approximately 70.6%.

19. OTHER INCOME AND EXPENSE

The components of other income are summarized as follows:

	Years Ended December 31,		
	2011	2010	2009
		(in millions)	
Gain on extinguishment of tax and other liabilities	$ 14	$ 62	$168
Tax credit settlement	31	—	129
Performance incentive fee	—	—	80
Gain on sale of assets	47	12	14
Other	57	26	68
Total other income	$149	$100	$459

Other income generally includes gains on asset sales and extinguishments of liabilities, favorable judgments on contingencies, and other income from miscellaneous transactions.

Other income of $149 million for the year ended December 31, 2011 included an additional tax credit settlement from a favorable court decision in 2011 concerning reimbursement of excess non-income taxes paid from 1989 to 1992 at Eletropaulo and the reimbursement of income tax expense recognized related to an indemnity agreement between Los Mina and the Dominican Republic government. Other income also includes the gain on the sale of assets at Gener and Eletropaulo, sale of Huntington Beach units 3 & 4 at Southland and sale of land and minerals rights at IPL.

Other income of $100 million for the year ended December 31, 2010 included the extinguishment of a swap liability owed by two of our Brazilian subsidiaries, resulting in the recognition of a $62 million gain. The net impact to the Company after taxes and noncontrolling interest was $9 million. Other income also included a gain on sale of assets at Eletropaulo.

Other income of $459 million for the year ended December 31, 2009 included $165 million from the reduction in interest and penalties associated with federal tax debts at Eletropaulo and Sul as a result of the Programa de Recuperacao Fiscal ("REFIS") program and a $129 million gain related to a favorable court decision enabling Eletropaulo to receive reimbursement of excess non-income taxes paid from 1989 to 1992 in the form of tax credits to be applied against future tax liabilities. The net impact to the Company after income taxes and noncontrolling interests for these items was $44 million. In addition, the Company recognized income of $80 million from a performance incentive bonus for management services provided to Ekibastuz and Maikuben in 2008.

The management agreement was related to the sale of these businesses in Kazakhstan in May 2008; see further discussion of this transaction in Note 23—*Acquisitions and Dispositions*.

The components of other expense are summarized as follows:

	Years Ended December 31,		
	2011	2010	2009
		(in millions)	
Loss on sale and disposal of assets	$ 70	$ 84	$ 33
Gener gas settlement	—	72	—
Loss on extinguishment of debt	62	37	—
Wind Generation transaction costs	—	22	—
Other	24	19	71
Total other expense	$156	$234	$104

Other expense generally includes losses on asset sales, losses on extinguishment of debt, legal contingencies and losses from other miscellaneous transactions.

Other expense of $156 million for the year ended December 31, 2011 included $36 million that is primarily related to the premium paid on early retirement of debt at Gener, $15 million related to the early retirement of senior notes due in 2011 at IPALCO and loss on disposal of assets at Eletropaulo and TermoAndes.

Other expense of $234 million for the year ended December 31, 2010 included $72 million for a settlement agreement of gas transportation contracts at Gener. There were also previously capitalized transaction costs of $22 million that were incurred in connection with the preparation for the sale of a noncontrolling interest in our Wind Generation business. These costs were written off upon the expiration of the letter of intent on June 30, 2010. In addition, there were losses on disposal of assets at Eletropaulo, Panama, and Gener, an $18 million loss on debt extinguishment at Andres and Itabo, and a $15 million loss at the Parent Company from the retirement of senior notes.

Other expense of $104 million for the year ended December 31, 2009 included a $13 million loss recognized when three of our businesses in the Dominican Republic received $110 million par value bonds issued by the Dominican Republic government to settle existing accounts receivable for the same amount from the government-owned distribution companies. The loss represented an adjustment to reflect the fair value of the bonds on the date received. Other expenses also included losses on the disposal of assets at Eletropaulo and Andres and contingencies at Alicura in Argentina and our businesses in Kazakhstan.

20. IMPAIRMENT EXPENSE

Asset Impairment

Asset impairment expense for the year ended December 31, 2011 consisted of:

	2011
	(in millions)
Wind turbines & deposits	$116
Tisza II	52
Kelanitissa	42
Other	15
Total	$225

Wind Turbines & Deposits—During the third quarter of 2011, the Company evaluated the future use of certain wind turbines held in storage pending their installation. Due to reduced wind turbine market pricing and advances in turbine technology, the Company determined it was more likely than not that the turbines would be sold significantly before the end of their previously estimated useful lives. In addition, the Company has concluded that more likely than not non-refundable deposits it had made in prior years to a turbine manufacturer for the purchase of wind turbines are not recoverable. The Company determined it was more likely than not that it would not proceed with the purchase of turbines due to the availability of more advanced and lower cost turbines in the market. These developments were more likely than not as of September 30, 2011 and as a result were considered impairment indicators and the Company determined that an impairment had occurred as of September 30, 2011 as the aggregate carrying amount of $161 million of these assets was not recoverable and was reduced to their estimated fair value of $45 million determined under the market approach. This resulted in asset impairment expense of $116 million. Wind Generation is reported in the Corporate and Other segment. In January 2012, the Company forfeited the deposits for which a full impairment charge was recognized in the third quarter of 2011, and there is no obligation for further payments under the related turbine supply agreement. Additionally, the Company sold some of the turbines held in storage during the fourth quarter of 2011 and is continuing to evaluate the future use of the turbines held in storage. The Company determined it is more likely than not that they will be sold, however they are not being actively marketed for sale at this time as the Company is reconsidering the potential use of the turbines in light of recent development activity at one of its advance stage development projects. It is reasonably possible that the turbines could incur further loss in value due to changing market conditions and advances in technology.

Tisza II—During the fourth quarter of 2011, Tisza II, a 900 MW gas and oil-fired generation plant in Hungary entered into annual negotiations with its offtaker. As a result of these negotiations, as well as the further deterioration of the economic environment in Hungary, the Company determined that an indicator of impairment existed at December 31, 2011. Thus, the Company performed an asset impairment test and determined that based on the undiscounted cash flow analysis, the carrying amount of Tisza II asset group was not recoverable. The fair value of the asset group was then determined using a discounted cash flow analysis. The carrying value of the Tisza II asset group of $94 million exceeded the fair value of $42 million resulting in the recognition of asset impairment expense of $52 million during the three months ended December 31, 2011. Tisza II is reported in the Europe Generation reportable segment.

Kelanitissa—In 2011, the Company recognized asset impairment expense of $42 million for the long-lived assets of Kelanitissa, our diesel-fired generation plant in Sri Lanka. We have continued to evaluate the recoverability of our long-lived assets at Kelanitissa as a result of both the existing government regulation which may require the government to acquire an ownership interest and the current expectation of future losses. Our evaluation indicated that the long-lived assets were no longer recoverable and, accordingly, they were written down to their estimated fair value of $24 million based on a discounted cash flow analysis. The long-lived assets had a carrying amount of $66 million prior to the recognition of asset impairment expense. Kelanitissa is a Build-operate-transfer (BOT) generation facility and payments under its PPA are scheduled to decline over the PPA term. It is possible that further impairment charges may be required in the future as Kelanitissa gets closer to the BOT date. Kelanitissa is reported in the Asia Generation reportable segment.

Asset impairment expense for the year ended December 31, 2010 consisted of:

	2010 (in millions)
Southland (Huntington Beach)	$200
Tisza II	85
Deepwater	79
Other	25
Total	$389

Southland—In September 2010, a new environmental policy on the use of ocean water to cool generation facilities was issued in California that requires generation plants to comply with the policy by December 31, 2020 and would require significant capital expenditure or plants' shutdown. The Company's Huntington Beach gas-fired generation facility in California, which is part of AES' Southland business, was impacted by the new policy. The Company performed an asset impairment test and determined the fair value of the asset group using a discounted cash flow analysis. The carrying value of the asset group of $288 million exceeded the fair value of $88 million resulting in the recognition of asset impairment expense of $200 million for the year ended December 31, 2010. Southland is reported in the North America Generation reportable segment.

Tisza II—During the third quarter of 2010, the Company entered into annual negotiations with the offtaker of Tisza II. As a result of these preliminary negotiations, as well as the further deterioration of the economic environment in Hungary, the Company determined that an indicator of impairment existed at September 30, 2010. Thus, the Company performed an asset impairment test and determined that based on the undiscounted cash flow analysis, the carrying amount of the Tisza II asset group was not recoverable. The fair value of the asset group was then determined using a discounted cash flow analysis. The carrying value of the Tisza II asset group of $160 million exceeded the fair value of $75 million resulting in the recognition of asset impairment expense of $85 million during the year ended December 31, 2010.

Deepwater—In 2010, Deepwater, our 160 MW petcoke-fired merchant power plant located in Texas, experienced deteriorating market conditions due to increasing petcoke prices and diminishing power prices. As a result, Deepwater incurred operating losses and was shut down from time to time to avoid negative operating margin. In the fourth quarter of 2010, management concluded that, on an undiscounted cash flow basis, the carrying amount of the asset group was no longer recoverable. The fair value of Deepwater was determined using a discounted cash flow analysis and $79 million of impairment expense was recognized. Deepwater is reported in the North America Generation reportable segment.

Asset impairment expense for the year ended December 31, 2009 consisted of:

	2009
	(in millions)
Piabanha	$11
Other	9
Total	$20

During the fourth quarter of 2009, the Company recognized a pre-tax long-lived asset impairment charge of $11 million related to the Company's Piabanha hydro project in Brazil. The Company determined that the carrying value exceeded the future discounted cash flows and abandoned the project. Piabanha is reported in the Company's Latin America Generation segment.

21. INCOME TAXES

INCOME TAX PROVISION

The following table summarizes the expense for income taxes on continuing operations, for the years ended December 31, 2011, 2010 and 2009:

	December 31,		
	2011	2010	2009
	(in millions)		
Federal:			
Current	$ —	$ (8)	$ 3
Deferred	(146)	(121)	(164)
State:			
Current	1	1	—
Deferred	2	(19)	(10)
Foreign:			
Current	852	678	527
Deferred	(73)	48	201
Total	$ 636	$ 579	$ 557

EFFECTIVE AND STATUTORY RATE RECONCILIATION

The following table summarizes a reconciliation of the U.S. statutory federal income tax rate to the Company's effective tax rate, as a percentage of income from continuing operations before taxes for the years ended December 31, 2011, 2010 and 2009:

	December 31,		
	2011	2010	2009
Statutory Federal tax rate	35%	35%	35%
State taxes, net of Federal tax benefit	0%	-2%	-1%
Taxes on foreign earnings	-3%	-2%	-5%
Valuation allowance	-3%	0%	0%
Gain (loss) on sale of businesses	0%	4%	-3%
Chilean withholding tax reversals	0%	-3%	0%
Other—net	0%	-1%	-1%
Effective tax rate	29%	31%	25%

The current income taxes receivable and payable are included in Other Current Assets and Accrued and Other Liabilities, respectively, on the accompanying Consolidated Balance Sheets. The noncurrent income taxes receivable and payable are included in Other Assets and Other Long-Term Liabilities, respectively, on the accompanying Consolidated Balance Sheets. The following table summarizes the income taxes receivable and payable as of December 31, 2011 and 2010:

	December 31,	
	2011	2010
	(in millions)	
Income taxes receivable—current	$565	$504
Income taxes receivable—noncurrent	21	21
Total income taxes receivable	$586	$525
Income taxes payable—current	$773	$678
Income taxes payable—noncurrent	3	5
Total income taxes payable	$776	$683

DEFERRED INCOME TAXES—Deferred income taxes reflect the net tax effects of (a) temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and (b) operating loss and tax credit carryforwards. These items are stated at the enacted tax rates that are expected to be in effect when taxes are actually paid or recovered.

As of December 31, 2011, the Company had federal net operating loss carryforwards for tax purposes of approximately $2.1 billion expiring in years 2023 to 2031. Approximately $73 million of the net operating loss carryforward related to stock option deductions will be recognized in additional paid-in capital when realized. The Company also had federal general business tax credit carryforwards of approximately $18 million expiring primarily from 2020 to 2031, and federal alternative minimum tax credits of approximately $5 million that carryforward without expiration. The Company had state net operating loss carryforwards as of December 31, 2011 of approximately $5.0 billion expiring in years 2013 to 2031. As of December 31, 2011, the Company had foreign net operating loss carryforwards of approximately $3.1 billion that expire at various times beginning in 2012 and some of which carryforward without expiration, and tax credits available in foreign jurisdictions of approximately $23 million, $1 million of which expire in 2012 to 2014, $4 million of which expire in 2015 to 2022 and $18 million of which carryforward without expiration.

Valuation allowances decreased $374 million during 2011 to $0.9 billion at December 31, 2011. This net decrease was primarily the result of the release of a valuation allowance against certain foreign operating loss carryforwards which were written off in 2011 and a release of a valuation allowance at one of our Brazillian subsidiaries.

Valuation allowances decreased $322 million during 2010 to $1.3 billion at December 31, 2010. This net decrease was primarily the result of the release of valuation allowances against deferred tax assets at foreign subsidiaries.

The Company believes that it is more likely than not that the net deferred tax assets as shown below will be realized when future taxable income is generated through the reversal of existing taxable temporary differences and income that is expected to be generated by businesses that have long-term contracts or a history of generating taxable income. The Company continues to monitor the utilization of its deferred tax asset for its U.S. consolidated net operating loss carryforward. Although management believes it is more likely than not that this deferred tax asset will be realized through generation of sufficient taxable income prior to expiration of the loss carryforwards, such realization is not assured.

The following table summarizes the deferred tax assets and liabilities, as of December 31, 2011 and 2010:

	December 31,	
	2011	2010
	(in millions)	
Differences between book and tax basis of property	$ 1,895	$ 1,260
Cumulative translation adjustment	38	94
Other taxable temporary differences	341	390
Total deferred tax liability	2,274	1,744
Operating loss carryforwards	(1,482)	(1,615)
Capital loss carryforwards	(112)	(84)
Bad debt and other book provisions	(465)	(522)
Retirement costs	(359)	(313)
Tax credit carryforwards	(46)	(52)
Other deductible temporary differences	(517)	(390)
Total gross deferred tax asset	(2,981)	(2,976)
Less: valuation allowance	906	1,280
Total net deferred tax asset	(2,075)	(1,696)
Net deferred tax (asset)/liability	$ 199	$ 48

The Company considers undistributed earnings of certain foreign subsidiaries to be indefinitely reinvested outside of the United States and, accordingly, no U.S. deferred taxes have been recorded with respect to such earnings in accordance with the relevant accounting guidance for income taxes. Should the earnings be remitted as dividends, the Company may be subject to additional U.S. taxes, net of allowable foreign tax credits. It is not practicable to estimate the amount of any additional taxes which may be payable on the undistributed earnings.

Income from operations in certain countries is subject to reduced tax rates as a result of satisfying specific commitments regarding employment and capital investment. The Company's income tax benefits related to the tax status of these operations are estimated to be $60 million, $60 million and $35 million for the years ended December 31, 2011, 2010 and 2009, respectively. The per share effect of these benefits after noncontrolling interests was $0.07, $0.07 and $0.04 for the year ended December 31, 2011, 2010 and 2009, respectively.

The following table summarizes the income (loss) from continuing operations, before income taxes, net equity in earnings of affiliates and noncontrolling interests, for the years ended December 31, 2011, 2010 and 2009:

	December 31,		
	2011	2010	2009
		(in millions)	
U.S.	$ (514)	$ (527)	$(1,028)
Non-U.S.	2,693	2,392	3,296
Total	$2,179	$1,865	$ 2,268

UNCERTAIN TAX POSITIONS

Uncertain tax positions have been classified as noncurrent income tax liabilities unless expected to be paid in one year. The Company's policy for interest and penalties related to income tax exposures is to recognize interest and penalties as a component of the provision for income taxes in the Consolidated Statements of Operations.

As of December 31, 2011 and 2010, the total amount of gross accrued income tax related interest included in the Consolidated Balance Sheets was $15 million and $12 million, respectively. The total amount of gross accrued income tax related penalties included in the Consolidated Balance Sheets as of December 31, 2011 and 2010 was $4 million and $4 million, respectively.

The total expense (benefit) for interest related to unrecognized tax benefits for the years ended December 31, 2011, 2010 and 2009 amounted to $3 million, $(10) million and $4 million, respectively. For the years ended December 31, 2011, 2010 and 2009, the total expense (benefit) for penalties related to unrecognized tax benefits amounted to $0 million, $(1) million and $0 million, respectively.

We are potentially subject to income tax audits in numerous jurisdictions in the U.S. and internationally until the applicable statute of limitations expires. Tax audits by their nature are often complex and can require several years to complete. The following is a summary of tax years potentially subject to examination in the significant tax and business jurisdictions in which we operate:

Jurisdiction	Tax Years Subject to Examination
Argentina	2005-2011
Brazil	2006-2011
Cameroon	2007-2011
Chile	1998-2011
Colombia	2008-2011
El Salvador	2008-2011
United Kingdom	2008-2011
United States (Federal)	1994-2011

As of December 31, 2011, 2010 and 2009, the total amount of unrecognized tax benefits was $471 million, $437 million and $510 million, respectively. The total amount of unrecognized tax benefits that would benefit the effective tax rate as of December 31, 2011, 2010 and 2009 is $424 million, $412 million and $484 million, respectively, of which $47 million, $51 million and $55 million, respectively, would be in the form of tax attributes that would warrant a full valuation allowance.

The total amount of unrecognized tax benefits anticipated to result in a net decrease to unrecognized tax benefits within 12 months of December 31, 2011 is estimated to be between $25 million and $34 million.

The following is a reconciliation of the beginning and ending amounts of unrecognized tax benefits for the years ended December 31, 2011, 2010 and 2009:

	2011	2010	2009
		(in millions)	
Balance at January 1	$437	$510	$ 554
Additions for current year tax positions	7	14	72
Additions for tax positions of prior years	49	51	7
Reductions for tax positions of prior years	(18)	(46)	(9)
Effects of foreign currency translation	(1)	(2)	6
Settlements	—	(67)	(104)
Lapse of statute of limitations	(3)	(23)	(16)
Balance at December 31	$471	$437	$ 510

The amount of settlements of uncertain tax positions in 2009 was primarily the result of a non-cash audit settlement for $105 million at a Brazilian subsidiary which resulted in no tax expense or benefit.

The Company and certain of its subsidiaries are currently under examination by the relevant taxing authorities for various tax years. The Company regularly assesses the potential outcome of these examinations in each of the taxing jurisdictions when determining the adequacy of the amount of unrecognized tax benefit recorded. While it is often difficult to predict the final outcome or the timing of resolution of any particular uncertain tax position, we believe we have appropriately accrued for our uncertain tax benefits. However, audit outcomes and the timing of audit settlements and future events that would impact our previously recorded unrecognized tax benefits and the range of anticipated increases or decreases in unrecognized tax benefits are subject to significant uncertainty. It is possible that the ultimate outcome of current or future examinations may exceed our provision for current unrecognized tax benefits in amounts that could be material, but cannot be estimated as of December 31, 2011. Our effective tax rate and net income in any given future period could therefore be materially impacted.

22. DISCONTINUED OPERATIONS AND HELD FOR SALE BUSINESSES

Discontinued operations include the results of the following businesses:

- Argentina distribution businesses (sold in November 2011);
- Eletropaulo Telecomunicacões Ltda. and AES Communications Rio de Janeiro S.A. (collectively, “Brazil Telecom”), our Brazil telecommunication businesses (sold in October 2011);
- Carbon reduction projects (held for sale in December 2011);
- Wind projects (abandoned in December 2011);
- Eastern Energy in New York (held for sale in March 2011);
- Borsod in Hungary (held for sale in March 2011);
- Thames in Connecticut (disposed of in December 2011);
- Barka in Oman (sold in August 2010);
- Lal Pir and Pak Gen in Pakistan (sold in June 2010); and
- Ras Laffan in Qatar (sold in October 2010).

Information for businesses included in discontinued operations and the income (loss) on disposal and impairment on discontinued operations for the years ended December 31, 2011, 2010 and 2009 is provided in the tables below:

	Year ended December 31,		
	2011	2010	2009
		(in millions)	
Revenue	$ 485	$1,310	$1,579
Income (loss) from operations of discontinued businesses, before taxes	$(124)	$ (745)	$ 146
Income tax (expense) benefit	27	270	(45)
Income (loss) from operations of discontinued businesses, after taxes	$ (97)	$ (475)	$ 101
Gain (loss) on disposal of discontinued businesses, after taxes	$ 86	$ 64	$ (150)

Gain (Loss) on Disposal of Discontinued Businesses

	Year ended December 31,		
Subsidiary	2011	2010	2009
		(in millions)	
Argentina distribution businesses	$(338)	$—	$ —
Brazil Telecom	446	—	—
Wind projects	(22)	—	—
Barka	—	80	—
Lal Pir	—	(6)	(74)
Pak Gen	—	(16)	(76)
Ras Laffan	—	6	—
Gain (loss) on disposal, after taxes	$ 86	$ 64	$(150)

Argentina distribution businesses—On November 17, 2011, the Company completed the sale of its 90% equity interest in Edelap and Edes, two distribution companies in Argentina serving approximately 329,000 and 172,000 customers, respectively, and its 51% equity interest in Central Dique, a 68 MW gas and diesel generation plant (collectively, "Argentina distribution businesses") in Argentina. Net proceeds from the sale were approximately $4 million. The Company recognized a loss on disposal of $338 million, net of tax, including $208 million due to the recognition of cumulative translation losses. These businesses were previously reported in the Latin America Utilities segment.

Brazil Telecom—In October 2011, a subsidiary of the Company completed the sale of its ownership interest in two telecommunication companies in Brazil. The Company held approximately 46% ownership interest in these companies through the subsidiary. The subsidiary received net proceeds of approximately $893 million. The gain on sale was approximately $446 million, net of tax. These businesses were previously reported in the Latin America Utilities segment.

Carbon reduction projects — In December 2011, the Company's board of directors approved plans to sell its 100% equity interests in its carbon reduction businesses in Asia and Latin America. The aggregate carrying amount of $49 million of these projects was written down as their estimated fair value was considered zero, resulting in a pre-tax impairment expense of $40 million, which is included in income from operations of discontinued businesses. The impairment expense recognized was limited to the carrying amounts of the individual assets within the asset group, where the fair value was greater than the carrying amount. When the disposal group met the held for sale criteria, the disposal group was measured at the lower of carrying amount or fair value less cost to sell. Carbon reduction projects were previously reported in "Corporate and Other".

Wind projects—In the fourth quarter of 2011, the Company determined that it would no longer pursue certain development projects in Poland and the United Kingdom due to revisions in its growth strategy. As a result, the Company abandoned these projects and recognized the related project development rights, which were previously included in intangible assets, as a loss on disposal of discontinued operations of $22 million, net of tax. These wind projects were previously reported in "Corporate and Other".

Eastern Energy—In March 2011, AES Eastern Energy ("AEE") met the held for sale criteria and was reclassified from continuing operations to held for sale. AEE operates four coal-fired power plants: Cayuga, Greenidge, Somerset and Westover, representing generation capacity of 1,169 MW in the western New York power market. In 2010, AEE had recognized a pre-tax impairment expense of $827 million due to adverse market conditions. AEE along with certain of its affiliates is currently under bankruptcy protection and is recorded as a cost method investment. See Note 1 —*General and Summary of Significant Accounting Policies* for further information. AEE was previously reported in the North America Generation segment.

Borsod—In March 2011, Borsod, which holds two coal/biomass-fired generation plants in Hungary with generating capacity of 161 MW, met the held for sale criteria and was reclassified from continuing operations to held for sale. Borsod is currently under liquidation and is recorded as a cost method investment. See Note 1 — *General and Summary of Significant Accounting Policies* for further information. Borsod was previously reported in the Europe Generation segment.

Thames—In December 2011, Thames, a 208 MW coal-fired plant in Connecticut, met the discontinued operations criteria and its operating results were retrospectively reflected as discontinued operations. Thames is currently under liquidation and is recorded as a cost method investment with the historical operating results reflected in discontinued operations. See Note 1 —*General and Summary of Significant Accounting Policies* for further information. Thames was previously reported in the North America Generation segment.

Barka—On August 19, 2010, the Company completed the sale of its 35% ownership interest in Barka, a 456 MW combined cycle gas facility and water desalination plant in Oman, and its 100% interest in two Barka related service companies. Total consideration received in the transaction was approximately $170 million, of which $124 million was AES' portion. The Company recognized a gain on disposal of $80 million, net of tax, during the year ended December 31, 2010. Barka was previously reported in the Asia Generation segment.

Lal Pir and Pak Gen—On June 11, 2010, the Company completed the sale of its 55% ownership in Lal Pir and Pak Gen, two oil-fired facilities in Pakistan with respective generation capacities of 362 MW and 365 MW. Total consideration received in the transaction was approximately $117 million, of which $65 million was AES' portion. The Company recognized a loss on disposal of $150 million, net of tax, during the year ended December 31, 2009 and impairment losses totaling $22 million, net of tax, during the year ended December 31, 2010 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. These businesses were previously reported in the Asia Generation segment.

Ras Laffan—On October 20, 2010, the Company completed the sale of its 55% equity interest in Ras Laffan, a 756 MW combined cycle gas plant and a water desalination facility in Qatar, and the associated operations company for an aggregate proceeds of approximately $234 million. The Company recognized a gain on disposal of $6 million, net of tax, during the year ended December 31, 2010. Ras Laffan was previously reported in the Asia Generation segment.

23. ACQUISITIONS AND DISPOSITIONS

Acquisitions

DPL— On November 28, 2011, AES completed its acquisition of 100% of the common stock of DPL for approximately $3.5 billion, pursuant to the terms and conditions of a definitive agreement (the "Merger Agreement") dated April 19, 2011. DPL serves over 500,000 customers, primarily West Central Ohio, through its operating subsidiaries DP&L and DPL Energy Resources ("DPLER"). Additionally, DPL operates over 3,800 MW of power generation facilities and provides competitive retail energy services to residential, commercial, industrial and governmental customers. The Acquisition strengthens the Company's U.S. utility operations by expanding in the Midwest and PJM, a regional transmission organization serving several eastern states as part of the Eastern Interconnection. The Company expects to benefit from the regional scale provided by Indianapolis Power & Light Company, its nearby integrated utility business in Indiana. AES funded the aggregate purchase consideration through a combination of the following:

- the proceeds from a $1.05 billion term loan obtained in May 2011;
- the proceeds from a private offering of $1.0 billion notes in June 2011;
- temporary borrowings of $251 million under its revolving credit facility; and
- the proceeds from private offerings of $450 million aggregate principal amount of 6.50% senior notes due 2016 and $800 million aggregate principal amount of 7.25% senior notes due 2021 (collectively, the "Notes") in October 2011 by Dolphin Subsidiary II, Inc. ("Dolphin II"), a wholly-owned special purpose indirect subsidiary of AES, which was merged into DPL upon the completion of acquisition.

The fair value of the consideration paid for DPL was as follows (in millions):

Agreed enterprise value	$ 4,719
Less: fair value of assumed long-term debt outstanding, net	(1,255)
Cash consideration paid to DPL's common stockholders	3,464
Add: cash paid for outstanding stock-based awards	19
Total cash consideration paid	$ 3,483

The preliminary allocation of the purchase price to the fair value of assets acquired and liabilities assumed is as follows (in millions):

Cash	$ 116
Accounts receivable	278
Inventory	124
Other current assets	41
Property, plant and equipment	2,549
Intangible assets subject to amortization	166
Intangible assets—indefinite-lived	5
Regulatory assets	201
Other noncurrent assets	58
Current liabilities	(401)
Non-recourse debt	(1,255)
Deferred taxes	(558)
Regulatory liabilities	(117)
Other noncurrent liabilities	(195)
Redeemable preferred stock	(18)
Net identifiable assets acquired	994
Goodwill	2,489
Net assets acquired	$ 3,483

At December 31, 2011, the assets acquired and liabilities assumed in the acquisition were recorded at provisional amounts based on the preliminary purchase price allocation. The Company is in the process of obtaining additional information to identify and measure all assets acquired and liabilities assumed in the acquisition within the measurement period, which could be up to one year from the date of acquisition. Such provisional amounts will be retrospectively adjusted to reflect any new information about facts and circumstances that existed at the acquisition date that, if known, would have affected the measurement of these amounts. Additionally, key input assumptions and their sensitivity to the valuation of assets acquired and liabilities assumed are currently being reviewed by management. It is likely that the value of the generation business related property, plant and equipment, the intangible asset related to the Electric Security Plan with its regulated customers and long-term coal contracts, the 4.9% equity ownership interest in the Ohio Valley Electric Corporation, and deferred taxes could change as the valuation process is finalized. DPLER, DPL's wholly-owned Competitive Retail Electric Service ("CRES") provider, will also likely have changes in its initial purchase price allocation for the valuation of its intangible assets for the trade name, and customer relationships and contracts.

As noted in the table above, the preliminary purchase price allocation has resulted in the recognition of $ 2.5 billion of goodwill. Factors primarily contributing to a price in excess of the fair value of the net tangible and intangible assets include, but are not limited to: the ability to expand the U.S. utility platform in the Mid-West market, the ability to capitalize on utility management experience gained from IPL, enhanced ability to negotiate with suppliers of fuel and energy, the ability to capture value associated with AES' U.S. tax position, a well-positioned generating fleet, the ability of DPL to leverage its assembled workforce to take advantage of growth opportunities, etc. Our ability to realize the benefit of DPL's goodwill depends on the realization of expected benefits resulting from a successful integration of DPL into AES' existing operations and our ability to respond to the changes in the Ohio utility market. For example, utilities in Ohio continue to face downward pressure on operating margins due to the evolving regulatory environment, which is moving towards a market-based competitive pricing mechanism. At the same time, the declining energy prices are also reducing operating margins across the utility industry. These competitive forces could adversely impact the future operating performance of DPL and may result in impairment of its goodwill. Goodwill resulting from the acquisition has been assigned to two reporting units identified within DPL (i.e., DP&L, the regulated utility component and DPLER, the competitive retail component). However, the majority of the goodwill has been assigned to DP&L. DPL has been included in the North America Utility segment, which is primarily expected to benefit from the acquisition.

Actual DPL revenue and net income attributable to The AES Corporation included in AES' Consolidated Statement of Operations for the year ended December 31, 2011, and AES' unaudited pro forma 2011 and 2010 revenue and net income attributable to AES, including DPL, as if the acquisition had occurred January 1, 2010, are as follows:

	Revenue	Net Income (Loss) Attributable to The AES Corporation
	(in millions)	
Actual from November 28, 2011—December 31, 2011	$ 154	$ (6)
Pro forma for 2011 (unaudited)	$18,945	$116
Pro forma for 2010 (unaudited)	$17,659	$101

The pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of the results of operations that would have been achieved had the acquisition been completed on the dates indicated, or the future consolidated results of operations of AES.

Net income attributable to The AES Corporation in the table above has been reduced by the net of tax impact of pro forma adjustments of $92 million and $198 million for the years ended December 31, 2011 and 2010, respectively. These pro forma adjustments primarily include: the amortization of fair value adjustment of DPL's generation plant and equipment and intangible assets subject to amortization; interest expense on additional borrowings made to finance the acquisition; third-party acquisition-related costs (primarily investment banking, advisory, accounting and legal fees); and a reversal of bridge financing costs incurred in connection with the acquisition.

Ballylumford—In the second quarter of 2011, the Company finalized the purchase price allocation related to the acquisition of Ballylumford. There were no significant adjustments made to the preliminary purchase price allocation recorded in the third quarter of 2010 when the acquisition was completed.

Dispositions

Cartagena— On February 9, 2012, a subsidiary of the Company completed the sale of 80% of its interest in the wholly-owned holding company of AES Energia Cartagena S.R.L. ("AES Cartagena"), a 1,199 MW gas-fired generation business in Spain. AES owned approximately 71% of AES Cartagena through this holding company structure. Net proceeds from the sale were approximately €172 million ($229 million). Under the terms of the sale agreement, Electrabel International Holdings B.V., the buyer (a subsidiary of GDF SUEZ S.A. or "GDFS"), has an option to purchase AES' remaining 20% interest in the holding company for a fixed price of €28 million ($36 million) during a five month period beginning 13 months from February 9, 2012. Concurrent with the sale, GDFS settled the outstanding arbitration between the parties regarding certain emissions costs and other taxes that AES Cartagena sought to recover from GDFS as energy manager under the existing commercial arrangements. GDFS agreed to pay €71 million ($92 million) to AES Cartagena for such costs incurred by

AES Cartagena for the 2008—2010 period and for 2011 through the date of sale close, of which €28 million ($38 million) was paid at closing. See Item 3—*Legal Proceedings* of this Form 10-K for further information. Due to the Company's expected continuing ownership interest extending beyond one year from the completion of the sale of its 80% interest, prior period operating results of AES Cartagena have not been reclassified as discontinued operations.

Ekibastuz and Maikuben— In 2009, the Company recognized $80 million performance incentive bonus as "Other income" and $98.5 million upon termination of a management agreement as "Gain on sale of investments." These amounts related to the sale of two wholly-owned subsidiaries in Kazakhstan: Ekibastuz, a coal-fired generation plant, and Maikuben, a coal mine, which the Company had previously completed in 2008. Due to the Company's continuing involvement in the operations of these businesses extending beyond one year, their prior period operating results were not reclassified as discontinued operations. Excluding the amounts mentioned above, Ekibastuz and Maikuben generated no revenue or net income in 2011, 2010 and 2009.

24. 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 numerators and denominators of the basic and diluted earnings per share computations for income from continuing operations. In the table below, income represents the numerator (in millions) and shares represent the denominator (in millions):

	December 31, 2011			December 31, 2010			December 31, 2009		
	Income	Shares	$ per Share	Income	Shares	$ per Share	Income	Shares	$ per Share
BASIC EARNINGS PER SHARE									
Income from continuing operations attributable to The AES Corporation common stockholders	$458	778	$0.59	$484	769	$0.63	$724	667	$ 1.09
EFFECT OF DILUTIVE SECURITIES									
Stock options	—	2	—	—	2	—	—	1	—
Restricted stock units	—	3	—	—	3	—	—	2	(0.01)
DILUTED EARNINGS PER SHARE	$458	783	$0.59	$484	774	$0.63	$724	670	$ 1.08

The calculation of diluted earnings per share excluded 6,479,841, 16,618,137 and 18,035,813 options outstanding at December 31, 2011, 2010 and 2009, 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 of those options exceeded the average market price during the related period. In 2011, 2010 and 2009, all convertible debentures were omitted from the earnings per share calculation because they were antidilutive. In arriving at income attributable to AES Corporation common stockholders in computing basic earnings per share, dividends on preferred stock of our subsidiary were deducted.

In addition, on March 15, 2010, the Company issued 125,468,788 shares of common stock to an investor as described in Note 15—*Equity*.

25. RISKS AND UNCERTAINTIES

AES is a global power producer in 28 countries on five continents. See additional discussion of the Company's principal markets in Note 16—*Segment and Geographic Information*. Our principal lines of business are Generation and Utilities. The Generation line of business uses a wide range of technologies, including coal, gas, hydroelectric, and biomass as fuel to generate electricity. Our Utilities business is comprised of businesses that transmit, distribute, and in certain circumstances, generate power. In addition, the Company has operations in the renewables area. These efforts include projects primarily in wind and solar.

OPERATING AND ECONOMIC RISKS—The Company operates in several developing economies where economic downturns could have a significant impact on the overall macroeconomic conditions including the valuation of businesses. Deteriorating market conditions often expose the Company to the risk of decreased earnings and cash flows due to, among other factors, adverse fluctuations in the commodities and foreign currency spot markets. Additionally, credit markets around the globe continue to tighten their standards, which could impact our ability to finance growth projects through access to capital markets. Currently, the Company has a below-investment grade rating from Standard & Poor's of BB-. This may limit the ability of the Company to finance new and existing development projects to cash currently available on hand and through reinvestment of earnings. As of December 31, 2011, the Company had $1.7 billion of unrestricted cash and cash equivalents.

During 2011, approximately 87% of our revenue, and 53% of our revenue from discontinued businesses, was generated outside the United States and a significant portion of our international operations is conducted in developing countries. We continue to invest in projects in developing countries because the growth rates and the opportunity to implement operating improvements and achieve higher operating margins may be greater than those typically achievable in more developed countries. International operations, particularly the operation, financing and development of projects in developing countries, entail significant risks and uncertainties, including, without limitation:

- economic, social and political instability in any particular country or region;
- inability to economically hedge energy prices;
- volatility in commodity prices;
- adverse changes in currency exchange rates;
- government restrictions on converting currencies or repatriating funds;
- unexpected changes in foreign laws and regulations or in trade, monetary or fiscal policies;
- high inflation and monetary fluctuations;
- restrictions on imports of coal, oil, gas or other raw materials required by our generation businesses to operate;
- threatened or consummated expropriation or nationalization of our assets by foreign governments;
- unwillingness of governments, government agencies, similar organizations or other counterparties to honor their commitments;
- unwillingness of governments, government agencies, courts or similar bodies to enforce contracts that are economically advantageous to subsidiaries of the Company and economically unfavorable to counterparties, against such counterparties, whether such counterparties are governments or private parties;

- inability to obtain access to fair and equitable political, regulatory, administrative and legal systems;
- adverse changes in government tax policy;
- difficulties in enforcing our contractual rights or enforcing judgments or obtaining a just result in local jurisdictions; and
- potentially adverse tax consequences of operating in multiple jurisdictions.

Any of these factors, individually or in combination with others, could materially and adversely affect our business, results of operations and financial condition. In addition, our Latin American operations experience volatility in revenue and earnings which have caused and are expected to cause significant volatility in our results of operations and cash flows. The volatility is caused by regulatory and economic difficulties, political instability, indexation of certain PPAs to fuel prices, and currency fluctuations being experienced in many of these countries. This volatility reduces the predictability and enhances the uncertainty associated with cash flows from these businesses.

Our inability to predict, influence or respond appropriately to changes in law or regulatory schemes, including any inability to obtain reasonable increases in tariffs or tariff adjustments for increased expenses, could adversely impact our results of operations or our ability to meet publicly announced projections or analysts' expectations. Furthermore, changes in laws or regulations or changes in the application or interpretation of regulatory provisions in jurisdictions where we operate, particularly our Utilities businesses where electricity tariffs are subject to regulatory review or approval, could adversely affect our business, including, but not limited to:

- changes in the determination, definition or classification of costs to be included as reimbursable or pass-through costs;
- changes in the definition or determination of controllable or noncontrollable costs;
- adverse changes in tax law;
- changes in the definition of events which may or may not qualify as changes in economic equilibrium;
- changes in the timing of tariff increases;
- other changes in the regulatory determinations under the relevant concessions; or
- changes in environmental regulations, including regulations relating to GHG emissions in any of our businesses.

Any of the above events may result in lower margins for the affected businesses, which can adversely affect our results of operations.

FOREIGN CURRENCY RISKS—AES operates businesses in many foreign countries and such operations may be impacted by significant fluctuations in foreign currency exchange rates. The Company's financial position and results of operations have been significantly affected by fluctuations in the value of the Brazilian real, the Argentine peso, the Dominican Republic peso, the Euro, the Chilean peso, the Colombian peso and the Philippine peso relative to the U.S. Dollar.

CONCENTRATIONS—The Company does not have any significant concentration of customers and the sources of fuel supply. Although the Company operates in primarily two lines of business, its operations are very diversified geographically. Several of the Company's generation businesses rely on PPAs with one or a limited number of customers for the majority of, and in some case all of, the relevant business' output over the term of the PPAs. However, no single customer accounted for 10% or more of total revenue in 2011, 2010 or 2009.

The cash flows and results of operations of our businesses are dependent on the credit quality of their customers and the continued ability of their customers and suppliers to meet their obligations under PPAs and fuel supply agreements. If a substantial portion of the Company's long-term PPAs and/or fuel supply were modified or terminated, the Company would be adversely affected to the extent that it was unable to replace such contracts at equally favorable terms.

26. RELATED PARTY TRANSACTIONS

Our generation businesses in Panama are partially owned by the Government of Panama (the "Panamanian Government"). The Panamanian Government, in turn, partially owns the distribution companies within Panama. For the years ended December 31, 2011, 2010 and 2009, our Panamanian businesses recognized electricity sales to the Panamanian Government totaling $144 million, $146 million and $143 million, respectively. For the same period, our Panamanian businesses purchased electricity, which excludes transmission charges from the Panamanian Government, totaling $65 million, $21 million and $25 million, respectively. As of December 31, 2011 and 2010, our Panamanian businesses owed the Panamanian Government $1 million and $4 million, respectively, payable on normal trade terms. For the same period, the Panamanian Government owed our Panamanian businesses $19 million and $12 million, respectively, payable on normal trade terms.

Our generation businesses in the Dominican Republic are partially owned by the Government of the Dominican Republic (the "Dominican Government"). The Dominican Government, in turn, owns the distribution companies within the Dominican Republic. For the years ended December 31, 2011, 2010 and 2009, our Dominican Republic businesses recognized electricity sales to the Dominican Government totaling $227 million, $179 million and $204 million, respectively. For the same period, the Dominican Government owed our Dominican Republic businesses $100 million and $88 million, respectively, payable on normal trade terms.

During the year, the Company sold 19% of its interest in Mong Duong to Stable Investment Corporation, a subsidiary of China Investment Corporation. See Note 15—*Equity* for further information.

27. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Quarterly Financial Data

The following tables summarize the unaudited quarterly statements of operations for the Company for 2011 and 2010. Amounts have been restated to reflect discontinued operations in all periods presented and reflect all adjustments necessary in the opinion of management for a fair statement of the results for interim periods.

	Quarter Ended 2011			
	Mar 31	June 30	Sept 30	Dec 31[1]
	(in millions, except per share data)			
Revenue	$4,189	$4,471	$4,345	$4,269
Gross margin	1,005	1,005	1,029	1,095
Income from continuing operations, net of tax[2]	489	435	208	409
Discontinued operations, net of tax	(6)	(8)	(33)	36
Net income	$ 483	$ 427	$ 175	$ 445
Net income (loss) attributable to The AES Corporation	$ 224	$ 174	$ (131)	$ (209)
Basic income (loss) per share:				
Income from continuing operations attributable to The AES Corporation, net of tax	$ 0.30	$ 0.24	$ (0.08)	$ 0.13
Discontinued operations attributable to The AES Corporation, net of tax	(0.02)	(0.02)	(0.09)	(0.40)
Basic income (loss) per share attributable to The AES Corporation	$ 0.28	$ 0.22	$ (0.17)	$ (0.27)
Diluted income (loss) per share:				
Income from continuing operations attributable to The AES Corporation, net of tax	$ 0.30	$ 0.24	$ (0.08)	$ 0.12
Discontinued operations attributable to The AES Corporation, net of tax	(0.02)	(0.02)	(0.09)	(0.39)
Diluted income (loss) per share attributable to The AES Corporation	$ 0.28	$ 0.22	$ (0.17)	$ (0.27)

	Quarter Ended 2010			
	Mar 31	June 30	Sept 30	Dec 31
	(in millions, except per share data)			
Revenue	$3,836	$3,838	$3,924	$4,230
Gross margin	954	989	963	1,030
Income from continuing operations, net of tax[3]	378	422	285	385
Discontinued operations, net of tax	24	7	112	(554)
Net income	$ 402	$ 429	$ 397	$ (169)
Net income (loss) attributable to The AES Corporation	$ 187	$ 144	$ 114	$ (436)
Basic income (loss) per share:				
Income from continuing operations attributable to The AES Corporation, net of tax	$ 0.25	$ 0.19	$ 0.05	$ 0.16
Discontinued operations attributable to The AES Corporation, net of tax	0.02	(0.01)	0.09	(0.71)
Basic income (loss) per share attributable to The AES Corporation	$ 0.27	$ 0.18	$ 0.14	$ (0.55)
Diluted income (loss) per share:				
Income from continuing operations attributable to The AES Corporation, net of tax	$ 0.25	$ 0.19	$ 0.05	$ 0.16
Discontinued operations attributable to The AES Corporation, net of tax	0.02	(0.01)	0.09	(0.71)
Diluted income (loss) per share attributable to The AES Corporation	$ 0.27	$ 0.18	$ 0.14	$ (0.55)

(1) DPL was acquired on November 28, 2011 and its results of operations have been included in AES' consolidated results of operations from the date of acquisition. See Note 23—*Acquisitions and Dispositions* for further information.

(2) Includes pretax impairment expense of $33 million, $147 million and $62 million, for the second, third and fourth quarters of 2011, respectively. See Note 20—*Impairment Expense* and Note 9—*Goodwill and Other Intangible Assets* for additional discussion on these impairment expenses.

(3) Includes pretax impairment expense of $315 million and $95 million, for the third and fourth quarters of 2010, respectively. See Note 20—*Impairment Expense* and Note 9—*Goodwill and Other Intangible Assets* for additional discussion on these impairment expenses.

28. SUBSEQUENT EVENTS

Cartagena—The partial sale of Company's interest in Cartagena was completed on February 9, 2012. See Note 23—*Acquisitions and Dispositions* for further information.

Red Oak—On February 10, 2012, a subsidiary of the Company signed a sale agreement with a newly-formed portfolio company of Energy Capital Partners II, LP for the sale of 100% of its membership interest in AES Red Oak, LLC and AES Sayreville, two wholly-owned subsidiaries, that hold the Company's interest in Red Oak, an 832 MW gas-fired generation business in New Jersey, for $147 million, subject to customary purchase price adjustments. Under the terms of the sale agreement, the buyer will assume the existing net indebtedness of Red Oak. The sale is expected to close by the end of the first quarter of 2012 and the Company does not expect to recognize a loss on the sale. Red Oak is reported in the North America Generation segment.

Ironwood—On February 23, 2012, a subsidiary of the Company signed a sale agreement with an indirect wholly-owned subsidiary of PPL Corporation for the sale of 100% of its equity interest in AES Ironwood, Inc., a wholly-owned subsidiary, that holds the Company's interest in Ironwood, a 710 MW gas-fired generation business in Pennsylvania, for $87 million, subject to customary purchase price adjustments. Under the terms of the sale agreement, the buyer will assume the existing net indebtedness of Ironwood. The sale is expected to close by the end of the first quarter of 2012 and the Company does not expect to recognize a loss on the sale. Ironwood is reported in the North America Generation segment.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

The Company maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in the reports that the Company files or submits under the Securities Exchange Act of 1934, as amended (the "Exchange Act") is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), as appropriate, to allow timely decisions regarding required disclosures.

The Company carried out the evaluation required by Rules 13a-15(b) and 15d-15(b), under the supervision and with the participation of our management, including the CEO and CFO, of the effectiveness of our "disclosure controls and procedures" (as defined in the Exchange Act Rules 13a-15(e) and 15d-15(e)). Based upon this evaluation, the CEO and CFO concluded that as of December 31, 2011, our disclosure controls and procedures were effective.

On November 28, 2011, AES completed the acquisition of DPL and as a result, assets acquired and liabilities assumed in the acquisition have been included in AES's consolidated balance sheet at December 31, 2011. DPL's total assets and total liabilities represented 13% and 11% of AES's consolidated total assets and total liabilities, respectively, at December 31, 2011. DPL's net loss of $6 million for the period November 28, 2011 through December 31, 2011 was included in AES's consolidated statement of operations for the year ended December 31, 2011. As permitted by the SEC guidance, DPL's internal control over financial reporting has been excluded from management's formal evaluation of the effectiveness of AES's disclosure controls and procedures due to the timing of acquisition.

Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 13a-15(f) under the Exchange Act. The Company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and
- provide reasonable assurance that unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements are prevented or detected timely.

Management, including our CEO and CFO, does not expect that our internal controls will prevent or detect all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. In addition, any evaluation of the effectiveness of controls is subject to risks that those internal controls may become inadequate in future periods because of changes in business conditions, or that the degree of compliance with the policies or procedures deteriorates.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2011. In making this assessment, management used the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations ("COSO"). Based on this assessment management, believes that the Company maintained effective internal control over financial reporting as of December 31, 2011.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which appears herein.

The evaluation of internal control over financial reporting excludes DPL due to the reasons discussed in the *Conclusion Regarding the Effectiveness of Disclosure Control and Procedures* above.

Changes in Internal Control Over Financial Reporting:

AES is currently evaluating the impact of DPL's acquisition on its internal control over financial reporting. There were no changes that occurred during the quarter ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of The AES Corporation:

We have audited The AES Corporation's internal control over financial reporting as of December 31, 2011 based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The AES Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

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

As indicated in Item 9A, Management's Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of DPL Inc., which is included in the 2011 consolidated financial statements of The AES Corporation and constituted 13% and 11% of total assets and total liabilities, respectively, as of December 31, 2011 and 0.9% of revenue and contributed $6 million of net loss, respectively, for the year then ended. Our audit of internal control over financial reporting of The AES Corporation also did not include an evaluation of the internal control over financial reporting of DPL Inc.

In our opinion, The AES Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of The AES Corporation as of December 31, 2011 and 2010, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2011 of The AES Corporation and our report dated February 24, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

McLean, Virginia
February 24, 2012

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The following information is incorporated by reference from the Registrant's Proxy Statement for the Registrant's 2012 Annual Meeting of Stock Holders which the Registrant expects will be filed on or around February 28, 2012 (the "2012 Proxy Statement"):

- information regarding the directors required by this item found under the heading *Board of Directors*;
- information regarding AES's Code of Ethics found under the heading *AES Code of Business Conduct and Corporate Governance Guidelines*;
- information regarding compliance with Section 16 of the Exchange Act required by this item found under the heading *Governance Matters—Section 16(a) Beneficial Ownership Reporting Compliance*; and
- information regarding AES's Financial Audit Committee found under the heading *The Committees of the Board—Financial Audit Committee (the "Audit Committee").*

Certain information regarding executive officers required by this Item is set forth as a supplementary item in Part I hereof (pursuant to Instruction 3 to Item 401(b) of Regulation S-K). The other information required by this Item, to the extent not included above, will be contained in our 2012 Proxy Statement and is herein incorporated by reference.

ITEM 11. EXECUTIVE COMPENSATION

The following information is contained in the 2012 Proxy Statement and is incorporated by reference: the information regarding executive compensation contained under the heading *Compensation Discussion and Analysis* and the Compensation Committee Report on Executive Compensation under the heading *Report of the Compensation Committee*.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

(a) Security Ownership of Certain Beneficial Owners.

See the information contained under the caption "Security Ownership of Certain Beneficial Owners, Directors, and Executive Officers" of the Proxy Statement for the 2012 Annual Meeting of Shareholders of the Registrant, which information is incorporated herein by reference.

(b) Security Ownership of Directors and Executive Officers.

See the information contained under the caption "Security Ownership of Certain Beneficial Owners, Directors, and Executive Officers" of the Proxy Statement for the 2012 Annual Meeting of Shareholders of the Registrant, which information is incorporated herein by reference.

(c) Changes in Control.

None.

(d) Securities Authorized for Issuance under Equity Compensation Plans.

The following table provides information about shares of AES common stock that may be issued under AES' equity compensation plans, as of December 31, 2011:

Securities Authorized for Issuance under Equity Compensation Plans (As of December 31, 2011)

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and right	(b) Weighted average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders[(1)]	17,162,642[(2)]	$13.85	17,298,997
Equity compensation plans not approved by security holders[(3)]	32,339	$ 5.49	—
Total	17,194,981	$13.82	17,298,997

(1) The following equity compensation plans have been approved by the Company's Stockholders:

(A) The LTC Plan was adopted in 2003 and provided for 17,000,000 shares authorized for issuance thereunder. In 2008, an amendment to the Plan to provide an additional 12,000,000 shares was approved by AES's stockholders, bringing the total authorized shares to 29,000,000. In 2010, an additional amendment to the Plan to provide an additional 9,000,000 shares was approved by AES's stockholders, bringing the total authorized shares to 38,000,000. The weighted average exercise price of Options outstanding under this plan included in Column (b) is $14.60 (excluding RSU awards), with 17,298,997 shares available for future issuance.

(B) The AES Corporation 2001 Stock Option Plan adopted in 2001 provided for 15,000,000 shares authorized for issuance. The weighted average exercise price of Options outstanding under this plan included in Column (b) is $3.17. In conjunction with the 2010 amendment to the 2003 Long Term Compensation plan, ongoing award issuance from this plan was discontinued in 2010. Any remaining shares under this plan, which are not reserved for issuance under outstanding awards, are not available for future issuance and thus the amount of 5,393,189 shares is not included in Column (c) above.

(C) The AES Corporation 2001 Plan for outside directors adopted in 2001 provided for 2,750,000 shares authorized for issuance. The weighted average exercise price of Options outstanding under this plan included in Column (b) is $8.16. In conjunction with the 2010 amendment to the 2003 Long Term Compensation plan, ongoing award issuance from this plan was discontinued in 2010. Any remaining shares under this plan, which are not reserved for issuance under outstanding awards, are not available for future issuance and thus the amount of 2,029,678 shares is not included in Column (c) above.

(D) The AES Corporation Second Amended and Restated Deferred Compensation Plan for directors provided for 2,000,000 shares authorized for issuance. Column (b) excludes the Director stock units granted thereunder. In conjunction with the 2010 amendment to the 2003 Long Term Compensation Plan, ongoing award issuance from this plan was discontinued in 2010 as Director stock units will be issued from the 2003 Long Term Compensation Plan. Any remaining shares under this plan, which are not reserved for issuance under outstanding awards, are not available for future issuance and thus the amount of 105,341 shares is not included in Column (c) above.

(E) The AES Corporation Incentive Stock Option Plan adopted in 1991 provided for 57,500,000 shares authorized for issuance. The weighted average exercise price of Options outstanding under this plan included in Column (b) is $35.56. This plan terminated on June 1, 2001, such that no additional grants may be granted under the plan after that date. Any remaining shares under this plan, which are not reserved for issuance under outstanding awards, are not available for future issuance in light of this plan's termination and thus 24,353,052 shares are not included in Column (c) above.

(2) Includes 6,768,096 (of which 2,619,902 are vested and 4,148,194 are unvested) shares underlying RSU awards (assuming performance at a maximum level), 969,117 shares underlying Director stock unit awards, and 9,425,429 shares issuable upon the exercise of Stock Option grants, for an aggregate number of 17,162,642 shares.

(3) The AES Corporation 2001 Non-Officer Stock Option Plan provided for 12,000,000 shares authorized for issuance. The weighted average exercise price of Options outstanding under this plan shown in Column (b) is $5.49. In conjunction with the 2010 amendment to the 2003 Long Term Compensation plan, ongoing award issuance from this plan was discontinued in 2010. Any remaining shares under this plan, which are not reserved for issuance under outstanding awards, are not available for future issuance and thus the amount of 7,101,270 shares is not included in Column (c) above. This plan is described in the narrative below.

The AES Corporation 2001 Non-Officer Stock Option Plan (the "2001 Plan") was adopted by the Board on October 18, 2001, and became effective October 25, 2001. The 2001 Plan did not require approval of AES's stockholders under the SEC or NYSE rules and/or regulations at that time. All employees that are not officers, directors or beneficial owners of more than 10% of AES's common stock are eligible to participate in the 2001 Plan. The total aggregate number of shares for which Options can be granted pursuant to the 2001 Plan is 12 million. As of December 31, 2011, 16 employees held Options under the 2001 Plan. The exercise price of each Option awarded under the 2001 Plan is equal to the fair market value of AES's common stock on the grant date of the Option. Options under the 2001 Plan generally vest as to 50% of their underlying shares on each anniversary of the Option grant date; however, grants dated October 25, 2001 vested in one year. Unless otherwise provided by the Compensation Committee of the Board, upon the death or disability of an employee, or a change of control (as defined therein), all Options granted under the 2001 Plan will become fully vested and exercisable. Unless otherwise provided by the Compensation Committee of the Board, in the event that the employee's employment with the Company terminates for any reason other than death or disability, all Options held by such employee will automatically expire on the earlier of (a) the date the Option would have expired had the employee continued in such employment, and (b) 180 days after the date that such employee's employment ceases. The 2001 Plan expired on October 25, 2011.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information regarding related party transactions required by this item is included in the 2012 Proxy Statement found under the headings *Transactions with Related Persons, Proposal I: Election of Directors* and *The Committees of the Board* and are incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information concerning principal accountant fees and services included in the 2012 Proxy Statement contained under the heading *Information Regarding The Independent Registered Public Accounting Firm's Fees, Services and Independence* and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial Statements.

(b) Exhibits.

3.1 Sixth Restated Certificate of Incorporation of The AES Corporation is incorporated herein by reference to Exhibit 3.1 of the Company's Form 10-K for the year ended December 31, 2008.

3.2 By-Laws of The AES Corporation, as amended and incorporated herein by reference to Exhibit 3.1 of the Company's Form 8-K filed on August 11, 2009.

4 There are numerous instruments defining the rights of holders of long-term indebtedness of the Registrant and its consolidated subsidiaries, none of which exceeds ten percent of the total assets of the Registrant and its subsidiaries on a consolidated basis. The Registrant hereby agrees to furnish a copy of any of such agreements to the Commission upon request. Since these documents are not required filings under Item 601 of Regulation S-K, the Company has elected to file certain of these documents as Exhibits 4.(a)—4.(o).

4.(a) Junior Subordinated Indenture, dated as of March 1, 1997, between The AES Corporation and Wells Fargo Bank, National Association, as successor to Bank One, National Association (formerly known as The First National Bank of Chicago) is incorporated herein by reference to Exhibit 4.(a) of the Company's Form 10-K for the year ended December 31, 2008.

4.(b) Third Supplemental Indenture, dated as of October 14, 1999, between The AES Corporation and Wells Fargo Bank, National Association, as successor to Bank One, National Association is incorporated herein by reference to Exhibit 4.(b) of the Company's Form 10-K for the year ended December 31, 2008.

4.(c) Senior Indenture, dated as of December 8, 1998, between The AES Corporation and Wells Fargo Bank, National Association, as successor to Bank One, National Association (formerly known as The First National Bank of Chicago) is incorporated herein by reference to Exhibit 4.01 of the Company's Form 8-K filed on December 11, 1998 (SEC File No. 001-12291).

4.(d) Form of Second Supplemental Indenture, dated as of June 11, 1999, between The AES Corporation and Wells Fargo Bank, National Association, as successor to Bank One, National Association (formerly known as The First National Bank of Chicago) is incorporated herein by reference to Exhibit 4.01 of the Company's Form 8-K filed on June 11, 1999 (SEC File No. 001-12291).

4.(e) Third Supplemental Indenture, dated as of September 12, 2000, between The AES Corporation and Wells Fargo Bank, National Association, as successor to Bank One, National Association is incorporated herein by reference to Exhibit 4.(e) of the Company's Form 10-K for the year ended December 31, 2008.

4.(f) Form of Fifth Supplemental Indenture, dated as of February 9, 2001, between The AES Corporation and Wells Fargo Bank, National Association, as successor to Bank One, National Association is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on February 8, 2001 (SEC File No. 001-12291).

4.(g) Form of Sixth Supplemental Indenture, dated as of February 22, 2001, between The AES Corporation and Wells Fargo Bank, National Association, as successor to Bank One, National Association is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on February 21, 2001 (SEC File No. 001-12291).

4.(h) Ninth Supplemental Indenture, dated as of April 3, 2003, between The AES Corporation and Wells Fargo Bank, National Association (as successor by consolidation to Wells Fargo Bank Minnesota, National Association) is incorporated herein by reference to Exhibit 4.6 of the Company's Form S-4 filed on December 7, 2007.

4.(i) Form of Tenth Supplemental Indenture, dated as of February 13, 2004, between The AES Corporation and Wells Fargo Bank, National Association (as successor by consolidation to Wells Fargo Bank Minnesota, National Association) is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on February 13, 2004 (SEC File No. 001-12291).

4.(j) Eleventh Supplemental Indenture, dated as of October 15, 2007, between The AES Corporation and Wells Fargo Bank, National Association is incorporated herein by reference to Exhibit 4.7 of the Company's Form S-4 filed on December 7, 2007.

4.(k) Twelfth Supplemental Indenture, dated as of October 15, 2007, between The AES Corporation and Wells Fargo Bank, National Association is incorporated herein by reference to Exhibit 4.8 of the Company's Form S-4 filed on December 7, 2007.

4.(l) Thirteenth Supplemental Indenture, dated as of May 19, 2008, between The AES Corporation and Wells Fargo Bank, National Association is incorporated herein by reference to Exhibit 4.(l) of the Company's Form 10-K for the year ended December 31, 2008.

4.(m) Fourteenth Supplemental Indenture, dated as of April 2, 2009, between The AES Corporation and Wells Fargo Bank, National Association is incorporated herein by reference to Exhibit 99.1 of the Company's Form 8-K filed on April 2, 2009.

4.(n) Fifteenth Supplemental Indenture, dated as of June 15, 2011, between The AES Corporation and Wells Fargo Bank, National Association is incorporated herein by reference to Exhibit 4.3 of the Company's Form 8-K filed on June 15, 2011.

4.(o) Indenture, dated October 3, 2011, between Dolphin Subsidiary II, Inc. and Wells Fargo Bank, National Association is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on October 5, 2011.

10.1 The AES Corporation Profit Sharing and Stock Ownership Plan are incorporated herein by reference to Exhibit 4(c)(1) of the Registration Statement on Form S-8 (Registration No. 33-49262) filed on July 2, 1992.

10.2 The AES Corporation Incentive Stock Option Plan of 1991, as amended, is incorporated herein by reference to Exhibit 10.30 of the Company's Form 10-K for the year ended December 31, 1995 (SEC File No. 00019281).

10.3 Applied Energy Services, Inc. Incentive Stock Option Plan of 1982 is incorporated herein by reference to Exhibit 10.31 of the Registration Statement on Form S-1 (Registration No. 33-40483).

10.4 Deferred Compensation Plan for Executive Officers, as amended, is incorporated herein by reference to Exhibit 10.32 of Amendment No. 1 to the Registration Statement on Form S-1(Registration No. 33-40483).

10.5 Deferred Compensation Plan for Directors is incorporated herein by reference to Exhibit 10.9 of the Company's Form 10-Q for the quarter ended March 31, 1998 (SEC File No. 001-12291).

10.6 The AES Corporation Stock Option Plan for Outside Directors as amended is incorporated herein by reference to Appendix C of the Registrant's 2003 Proxy Statement filed on March 25, 2003 (SEC File No. 001-12291).

10.7	The AES Corporation Supplemental Retirement Plan is incorporated herein by reference to Exhibit 10.63 of the Company's Form 10-K for the year ended December 31, 1994 (SEC File No. 00019281).
10.7A	Amendment to The AES Corporation Supplemental Retirement Plan, dated March 13, 2008 is incorporated herein by reference to Exhibit 10.9.A of the Company's Form 10-K for the year ended December 31, 2007.
10.8	The AES Corporation 2001 Stock Option Plan is incorporated herein by reference to Exhibit 10.12 of the Company's Form 10-K for the year ended December 31, 2000 (SEC File No. 001-12291).
10.9	Second Amended and Restated Deferred Compensation Plan for Directors is incorporated herein by reference to Exhibit 10.13 of the Company's Form 10-K for the year ended December 31, 2000 (SEC File No. 001-12291).
10.10	The AES Corporation 2001 Non-Officer Stock Option Plan is incorporated herein by reference to Exhibit 10.12 of the Company's Form 10-K for the year ended December 31, 2002 (SEC File No. 001-12291).
10.10A	Amendment to the 2001 Stock Option Plan and 2001 Non-Officer Stock Option Plan, dated March 13, 2008 is incorporated herein by reference to Exhibit 10.12.A of the Company's Form 10-K for the year ended December 31, 2007.
10.11	The AES Corporation 2003 Long Term Compensation Plan, as amended and restated on April 22, 2010, is incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on April 27, 2010.
10.12	Form of AES Nonqualified Stock Option Award Agreement under The AES Corporation 2003 Long Term Compensation Plan (Outside Directors) is incorporated herein by reference to Exhibit 10.2 of the Company's Form 8-K filed on April 27, 2010.
10.13	Form of AES Performance Stock Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan (filed herewith).
10.14	Form of AES Restricted Stock Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan (filed herewith).
10.15	Form of AES Performance Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan (filed herewith).
10.16	Form of AES Nonqualified Stock Option Award Agreement under The AES Corporation 2003 Long Term Compensation Plan (filed herewith).
10.17	The AES Corporation Restoration Supplemental Retirement Plan, as amended and restated, dated December 29, 2008 is incorporated herein by reference to Exhibit 10.15 of the Company's Form 10-K for the year ended December 31, 2008.
10.18	The AES Corporation International Retirement Plan, as amended and restated on December 29, 2008 is incorporated herein by reference to Exhibit 10.16 of the Company's Form 10-K for the year ended December 31, 2008.
10.19	The AES Corporation Severance Plan, as amended and restated on October 28, 2011(filed herewith).
10.20	The AES Corporation Executive Severance Plan dated October 6, 2011 is incorporated herein by reference to Exhibit 10.3 of the Company's Form 10-Q for the period ended September 30, 2011.
10.21	The AES Corporation Performance Incentive Plan, as amended and restated on April 22, 2010 is incorporated herein by reference to Exhibit 10.4 of the Company's Form 8-K filed on April 27, 2010.

10.22	The AES Corporation Deferred Compensation Program For Directors dated February 17, 2012 (filed herewith).
10.23	The AES Corporation Amended and Restated Employment Agreement with Paul Hanrahan is incorporated herein by reference to Exhibit 99.1 of the Company's Form 8-K filed on December 31, 2008.
10.24	The AES Corporation Amended and Restated Employment Agreement with Victoria D. Harker is incorporated herein by reference to Exhibit 99.2 of the Company's Form 8-K filed on December 31, 2008.
10.25	The AES Corporation Employment Agreement with Andrés Gluski is incorporated herein by reference to Exhibit 99.3 of the Company's Form 8-K filed on December 31, 2008.
10.26	Separation Agreement, between Paul T. Hanrahan and The AES Corporation dated September 4, 2011 is incorporated by reference to Exhibit 10.1 of the Company's Form 10-Q for the period ended September 30, 2011.
10.27	Mutual Agreement, between Andrés Gluski and The AES Corporation dated October 7, 2011 is incorporated by reference to Exhibit 10.2 of the Company's Form 10-Q for the period ended September 30, 2011.
10.28	Amendment No. 2 to the Fourth Amended and Restated Credit and Reimbursement Agreement dated as of July 29, 2010 among the Company, the Subsidiary Guarantors, Citicorp USA, Inc., as Administrative Agent, Citibank N.A. as Collateral Agent and various lenders named therein is incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on July 30, 2010.
10.28A	Fifth Amended and Restated Credit and Reimbursement Agreement dated as of July 29, 2010 among The AES Corporation, a Delaware corporation, the Subsidiary Guarantors listed herein, the Banks listed on the signature pages thereof, Citicorp USA, Inc., as Administrative Agent, Citibank, N.A. as Collateral Agent, Citigroup Global Markets Inc., as Lead Arranger and Book Runner, Banc of America Securities LLC, as Lead Arranger and Book Runner and Co-Syndication Agent, Barclays Capital, as Lead Arranger and Book Runner and Co-Syndication Agent, RBS Securities Inc., as Lead Arranger and Book Runner and Co-Syndication Agent, RBS Securities Inc., as lead Arranger and Book Runner and Co-Syndication Agent, and Union Bank, N.A., as Lead Arranger and Book Runner and Co-Syndication Agent is incorporated herein by reference to Exhibit 10.1.A of the Company's Form 8-K filed on July 30, 2010.
10.28B	Appendices and Exhibits to the Fifth Amended and Restated Credit and Reimbursement Agreement, dated as of July 29, 2010 is incorporated herein by reference to Exhibit 10.1.B of the Company's Form 8-K filed on July 30, 2010.
10.28C	Exhibits B-1-B-7 to the Fifth Amended and Restated Credit and Reimbursement Agreement, dated as of July 29, 2010 are incorporated herein by reference to Exhibits 10.1.N-10.1.T of the Company's Form 10-Q for the period ending June 30, 2009.
10.28D	Amendment No.1 to and Waiver Under the Fifth Amended and Restated Credit and Reimbursement Agreement dated January 13, 2012 (filed herewith).
10.29	Collateral Trust Agreement dated as of December 12, 2002 among The AES Corporation, AES International Holdings II, Ltd., Wilmington Trust Company, as corporate trustee and Bruce L. Bisson, an individual trustee is incorporated herein by reference to Exhibit 4.2 of the Company's Form 8-K filed on December 17, 2002 (SEC File No. 001-12291).
10.30	Security Agreement dated as of December 12, 2002 made by The AES Corporation to Wilmington Trust Company, as corporate trustee and Bruce L. Bisson, as individual trustee is incorporated herein by reference to Exhibit 4.3 of the Company's Form 8-K filed on December 17, 2002 (SEC File No. 001-12291).

10.31	Charge Over Shares dated as of December 12, 2002 between AES International Holdings II, Ltd. and Wilmington Trust Company, as corporate trustee and Bruce L. Bisson, as individual trustee is incorporated herein by reference to Exhibit 4.4 of the Company's Form 8-K filed on December 17, 2002 (SEC File No. 001-12291).
10.32	Stock Purchase Agreement between The AES Corporation and Terrific Investment Corporation dated November 6, 2009 is incorporated herein by reference to Exhibit 10.1 of the Company's form 8-K filed on November 11, 2009.
10.33	Stockholder Agreement between The AES Corporation and Terrific Investment Corporation dated March 12, 2010 is incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on March 15, 2010.
10.34	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.
10.35	Credit Agreement dated as of May 27, 2011 among The AES Corporation, as borrower, the banks listed therein and Bank of America, N.A., as administrative agent is incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on June 1, 2011.
12	Statement of computation of ratio of earnings to fixed charges (filed herewith).
21	Subsidiaries of The AES Corporation (filed herewith).
23.1	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP (filed herewith).
24	Powers of Attorney (filed herewith).
31.1	Rule 13a-14(a)/15d-14(a) Certification of Andrés Gluski (filed herewith).
31.2	Rule 13a-14(a)/15d-14(a) Certification of Victoria D. Harker (filed herewith).
32.1	Section 1350 Certification of Andrés Gluski (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).

(c) Schedules

Schedule I—Condensed Financial Information of Registrant
Schedule II—Valuation and Qualifying Accounts

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE AES CORPORATION
(Company)

Date: February 24, 2012

By: /s/ ANDRÉS GLUSKI
Name: **Andrés Gluski**
President, Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the Company and in the capacities and on the dates indicated.

Name	Title	Date
* **Andrés Gluski**	President, Chief Executive Officer (Principal Executive Officer) and Director	February 24, 2012
* **Samuel W. Bodman, III**	Director	February 24, 2012
* **Zhang Guobao**	Director	February 24, 2012
* **Kristina Johnson**	Director	February 24, 2012
* **Tarun Khanna**	Director	February 24, 2012
* **John A. Koskinen**	Director	February 24, 2012
* **Philip Lader**	Director	February 24, 2012
* **John B. Morse**	Director	February 24, 2012
* **Sandra O. Moose**	Director	February 24, 2012
* **Philip A. Odeen**	Chairman of the Board and Lead Independent Director	February 24, 2012
* **Charles O. Rossotti**	Director	February 24, 2012
* **Sven Sandstrom**	Director	February 24, 2012
/s/ VICTORIA D. HARKER **Victoria D. Harker**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 24, 2012
/s/ MARY E. WOOD **Mary E. Wood**	Vice President and Controller (Principal Accounting Officer)	February 24, 2012
*BY: /s/ BRIAN A. MILLER ***Attorney-in-fact***		February 24, 2012

THE AES CORPORATION AND SUBSIDIARIES

INDEX TO FINANCIAL STATEMENT SCHEDULES

Schedules other than those listed above are omitted as the information is either not applicable, not required, or has been furnished in the financial statements or notes thereto included in Item 8 hereof.

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF REGISTRANT
UNCONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 189	$ 594
Restricted cash	50	10
Accounts and notes receivable from subsidiaries	871	839
Deferred income taxes	24	23
Prepaid expenses and other current assets	43	31
Total current assets	1,177	1,497
Investment in and advances to subsidiaries and affiliates	12,088	10,741
Office Equipment:		
Cost	81	93
Accumulated depreciation	(67)	(59)
Office equipment, net	14	34
Other Assets:		
Deferred financing costs (net of accumulated amortization of $74 and $39, respectively)	92	64
Deferred income taxes	525	352
Debt service reserves and other deposits	222	1
Total other assets	839	417
Total	$14,118	$12,689
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable	$ 21	$ 14
Accounts and notes payable to subsidiaries	317	253
Accrued and other liabilities	199	175
Term loan	—	200
Senior notes payable—current portion	305	263
Total current liabilities	842	905
Long-term Liabilities:		
Senior notes payable	5,663	3,632
Junior subordinated notes and debentures payable	517	517
Accounts and notes payable to subsidiaries	1,007	1,055
Other long-term liabilities	143	107
Total long-term liabilities	7,330	5,311
Stockholders' equity:		
Common stock	8	8
Additional paid-in capital	8,507	8,444
Retained earnings	678	620
Accumulated other comprehensive loss	(2,758)	(2,383)
Treasury stock	(489)	(216)
Total stockholders' equity	5,946	6,473
Total	$14,118	$12,689

See Notes to Schedule I

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF REGISTRANT
STATEMENTS OF UNCONSOLIDATED OPERATIONS

	For the Years Ended December 31		
	2011	2010	2009
	(in millions)		
Revenues from subsidiaries and affiliates	$ 59	$ 34	$ 39
Equity in earnings of subsidiaries and affiliates	357	590	983
Interest income	199	279	131
General and administrative expenses	(241)	(261)	(218)
Interest expense	(490)	(461)	(485)
Income before income taxes	(116)	181	450
Income tax benefit (expense)	174	(172)	208
Net income	$ 58	$ 9	$ 658

See Notes to Schedule I

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF REGISTRANT
STATEMENTS OF UNCONSOLIDATED CASH FLOWS

	For the Years Ended December 31,		
	2011	2010	2009
	(in millions)		
Net cash provided by operating activities	$ 1,569	$ 488	$ 178
Investing Activities:			
Investment in and advances to subsidiaries	(2,823)	(1,185)	(452)
(Purchase)/sale of short term investments, net	2	(3)	(5)
Return of capital	363	300	166
(Increase) decrease in restricted cash	(261)	(2)	4
Additions to property, plant and equipment	(28)	(22)	(8)
Net cash used in investing activities	(2,747)	(912)	(295)
Financing Activities:			
Borrowings under the revolver, net	295	—	—
Borrowings of notes payable and other coupon bearing securities	2,050	—	503
Repayments of notes payable and other coupon bearing securities	(477)	(914)	(154)
Loans (to) from subsidiaries	(744)	(154)	205
Proceeds from issuance of common stock	3	1,569	14
Purchase of treasury stock	(279)	(99)	—
Payments for deferred financing costs	(75)	(12)	(23)
Net cash provided by financing activities	773	390	545
Increase (decrease) in cash and cash equivalents	(405)	(34)	428
Cash and cash equivalents, beginning	594	628	200
Cash and cash equivalents, ending	$ 189	$ 594	$ 628
Supplemental Disclosures:			
Cash payments for interest, net of amounts capitalized	$ 392	$ 412	$ 410
Cash payments for income taxes, net of refunds	$ (6)	$ —	$ —

See Notes to Schedule I

THE AES CORPORATION

SCHEDULE I
NOTES TO SCHEDULE I

1. Application of Significant Accounting Principles

Accounting for Subsidiaries and Affiliates—The AES Corporation (the "Company") has accounted for the earnings of its subsidiaries on the equity method in the unconsolidated financial information.

Revenue—Construction management fees earned by the parent from its consolidated subsidiaries are eliminated.

Income Taxes—Positions taken on the Company's income tax return which satisfy a more-likely-than-not threshold will be recognized in the financial statements. The unconsolidated income tax expense or benefit computed for the Company reflects the tax assets and liabilities of the Company on a stand-alone basis and the effect of filing a consolidated U.S. income tax return with certain other affiliated companies.

Accounts and Notes Receivable from Subsidiaries—Certain prior period amounts have been reclassified to conform with current year presentation. Such amounts have been shown in current or long-term assets based on terms in agreements with subsidiaries, but payment is dependent upon meeting conditions precedent in the subsidiary loan agreements.

Selected Unconsolidated Balance Sheet Data:

	December 31, 2011	December 31, 2010
	(in millions)	
Assets		
Investment in and advances to subsidiaries and affiliates	$12,088	$10,741
Deferred income taxes	$ 525	$ 352
Total other assets	$ 839	$ 417
Total assets	$14,118	$12,689
Liabilities and Stockholders' Equity		
Other long-term liabilities	$ 143	$ 107
Total long-term liabilities	$ 7,330	$ 5,311
Additional paid-in capital	$ 8,507	$ 8,444
Retained earnings	$ 678	$ 620
Accumulated other comprehensive loss	$ (2,758)	$ (2,383)
Total stockholders' equity	$ 5,946	$ 6,473
Total liabilities and stockholders' equity	$14,118	$12,689

Selected Unconsolidated Operations Data:

	For the Year Ended December 31,		
	2011	2010	2009
	(in millions)		
Equity in earnings of subsidiaries and affiliates	$ 357	$ 590	$983
Income before income taxes	$(116)	$ 181	$450
Income tax benefit (expense)	$ 174	$(172)	$208
Net income attributable to The AES Corporation	$ 58	$ 9	$658

2. Notes Payable

	Interest Rate	Maturity	December 31, 2011	December 31, 2010
			(in millions)	
Senior Secured Term Loan	LIBOR + 1.75%	2011	$ —	$ 200
Senior Unsecured Note	8.875%	2011	—	129
Senior Unsecured Note	8.375%	2011	—	134
Senior Unsecured Note	7.75%	2014	500	500
Revolving Loan under Senior Secured Credit Facility[1]	LIBOR + 3.00%	2015	295	—
Senior Unsecured Note	7.75%	2015	500	500
Senior Unsecured Note	9.75%	2016	535	535
Senior Unsecured Note	8.00%	2017	1,500	1,500
Senior Secured Term Loan	LIBOR + 3.25%	2018	1,042	—
Senior Unsecured Note	8.00%	2020	625	625
Senior Unsecured Note	7.375%	2021	1,000	—
Term Convertible Trust Securities	6.75%	2029	517	517
Unamortized discounts			(29)	(28)
SUBTOTAL			$6,485	$4,612
Less: Current maturities			(305)	(463)
Total			$6,180	$4,149

(1) Subsequent to year end the loan was substantially repaid and is expected to be repaid in full prior to March 31, 2012.

December 31,	Annual Maturities
	(in millions)
2012	$ 305
2013	11
2014	509
2015	511
2016	523
Thereafter	4,626
Total debt	$6,485

3. Dividends from Subsidiaries and Affiliates

Cash dividends received from consolidated subsidiaries and from affiliates accounted for by the equity method were as follows:

	2011	2010	2009
	(in millions)		
Subsidiaries	$1,059	$944	$948
Affiliates	$ 25	$ 10	$ 60

4. Guarantees and Letters of Credit

GUARANTEES—In connection with certain of its project financing, acquisition, and power purchase agreements, the Company has expressly undertaken limited obligations and commitments, most of which will only be effective or will be terminated upon the occurrence of future events. These obligations and commitments, excluding those collateralized by letter of credit and other obligations discussed below, were limited as of December 31, 2011, by the terms of the agreements, to an aggregate of approximately $351 million representing 22 agreements with individual exposures ranging from less than $1 million up to $53 million.

LETTERS OF CREDIT—At December 31, 2011, the Company had $12 million in letters of credit outstanding under the senior unsecured credit facility representing 11 agreements with individual exposures ranging from less than $1 million up to $7 million, which operate to guarantee performance relating to certain project development and construction activities and subsidiary operations. At December 31, 2011, the Company had $261 million in cash collateralized letters of credit outstanding representing 13 agreements with individual exposures ranging from less than $1 million up to $221 million, which operate to guarantee performance relating to certain project development and construction activities and subsidiary operations. During 2011, the Company paid letter of credit fees ranging from 0.250% to 3.250% per annum on the outstanding amounts.

THE AES CORPORATION

SCHEDULE II
VALUATION AND QUALIFYING ACCOUNTS
(IN MILLIONS)

	Balance at Beginning of the Period	Charged to Cost and Expense	Amounts Written off	Translation Adjustment	Balance at the End of the Period
Allowance for accounts receivables (current and noncurrent)					
Year ended December 31, 2009	$239	$104	$(109)	$ 42	$276
Year ended December 31, 2010	276	53	(37)	3	295
Year ended December 31, 2011	295	43	(41)	(24)	273

AES Executive Leadership Team

Andrés Gluski
President and Chief Executive Officer

Ned Hall
Chief Operating Officer,
Global Generation
and Executive Vice President

Victoria Harker
Chief Financial Officer and
President of Global Business Services

Brian Miller
Executive Vice President,
General Counsel
and Corporate Secretary

Rita Trehan
Senior Vice President, Human Resources
and Internal Communications

Andrew Vesey
Chief Operating Officer, Global Utilities
and Executive Vice President

Gardner Walkup
Senior Vice President, Strategy

AES Board of Directors

Philip Odeen (Chairman)
Non-Executive Chairman, Convergys Corporation; former Chairman, Avaya Inc, Reynolds and Reynolds Company, and TRW Inc.; President and Chief Executive Officer, BDM

Samuel Bodman
Former Secretary of Energy; former President and Chief Operating Officer, Fidelity Investments; former Chairman, Chief Executive Officer and Director, Cabot Corporation

Andrés Gluski
President and Chief Executive Officer, The AES Corporation

Zhang Guo Bao
Vice-Chairman of the Chinese National Development and Reform Commission; former Administrator of the Chinese National Energy Administration

Kristina Johnson
CEO of Enduring Energy/Hydro, LLC and Former Undersecretary for Energy at the Department of Energy; former Provost and Senior Vice President for Academic Affairs at the Johns Hopkins University

Tarun Khanna
Jorge Paulo Lemann Professor at the Harvard Business School

John Koskinen
Former Non-Executive Chairman, Freddie Mac; former President, the U.S. Soccer Foundation; former Deputy Mayor and City Administrator, the District of Columbia; former President and Chief Executive Officer, The Palmieri Company

Philip Lader
Chairman, WPP Group plc; Senior Advisor, Morgan Stanley; former U.S. Ambassador to the Court of St. James's

Sandra Moose
President, Strategic Advisory Services LLC; Chairperson of the Board of Trustees, Natixis and Loomis Sayles Funds; former Senior Vice President and Director, The Boston Consulting Group

John Morse
Retired Senior Vice President Finance and CFO Washington Post Company; former Partner Price Waterhouse (now PricewaterhouseCoopers); and Trustee and President Emeritus of the College Foundation of The University of Virginia

Charles Rossotti
Senior Advisor, The Carlyle Group; former Commissioner, the IRS; former Founder and Chairman, American Management Systems, Inc.

Sven Sandstrom
CEO of Hand in Hand International and former Chair for International Funding Negotiations for the African Development Bank and the Global Fund to Fight AIDS, TB and Malaria

Company Information

Corporate Office
The AES Corporation
4300 Wilson Boulevard
Arlington, VA 22203
USA
703-522-1315

Website
www.aes.com

Stock Information
AES LISTED NYSE
Common stock of The AES Corporation trades under the symbol AES. The AES Corporation is proud to meet the listing requirements of the NYSE, the world's leading equities market.

Number of Shareholders
As of December 31, 2011 there were approximately 7,105 AES shareholders of record and 767,968,582 shares of AES common stock outstanding.

Transfer Agent
The AES Corporation has designated Computershare Investor Services ("Computershare") to be its transfer agent for AES common stock.

Please contact Computershare if you need assistance with lost or stolen AES stock certificates directly held by you, address changes, name changes and stock transfers.

By mail and overnight delivery:
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Investor Relations Information
Please visit the Investor Relations section of the AES website at www.aes.com, or you may contact a member of the AES Investor Relations team:
General: 703-682-6399 or
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AES Code of Conduct
AES is committed to demonstrating the highest standards of business ethics in all that we do. To that end, AES has adopted a Code of Conduct, which is available at our website.

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