AES

we are the energy

ANNUAL REPORT 2012

It is the energy of 25,000 AES people that delivers safe, reliable and sustainable power in every market we serve.

WE ARE THE ENERGY...

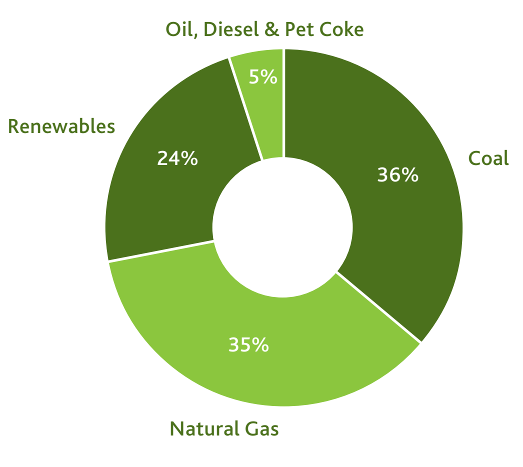
POWERING NATIONS	...in Chile, supplying more than one fifth of the country's annual energy demand.
STRENGTHENING SUPPLY	...in the Philippines, leveraging our knowledge to improve net production by 62% in two years.
BRINGING INNOVATION ONLINE	...in Puerto Rico, having built and now operating the largest solar plant in the Caribbean.
PARTNERING WITH COMMUNITIES	...in Brazil, transforming the lives of thousands of children and adults through programs promoting culture, citizenship and life skills.
HELPING WHEN IT'S NEEDED MOST	...in the U.S., responding outside our service territories when communities ravaged by Superstorm Sandy needed their power restored.

We are the energy improving millions of lives every day.

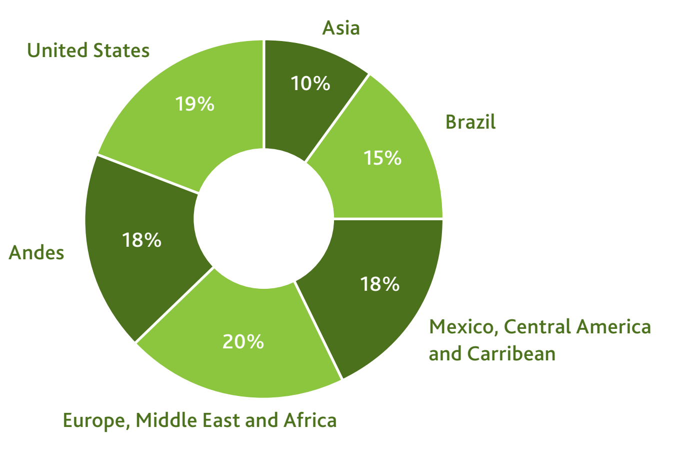
AES GLOBAL BUSINESS PORTFOLIO

- AES operates in 25 countries on 5 continents
- Total AES generation capacity is 39,429 megawatts
- AES delivered 101,062 gigawatt hours of energy to customers in 2012

MEGAWATTS BY FUEL TYPE



ADJUSTED PRE-TAX CONTRIBUTION BY STRATEGIC BUSINESS UNIT[1]



[1]See Financial Notes on Page 5 for definition and reconciliation.

CHAIRMAN AND CEO LETTER TO AES SHAREHOLDERS

2012 was a critical year in the execution of our new strategy. We made significant progress on our plan to create shareholder value. Despite adverse market conditions for some of our larger businesses, we remained focused on executing our strategic plan and took meaningful steps to deliver sustainable long-term value to our shareholders.

We began the year with a firm commitment to unlock shareholder value by optimizing capital allocation, improving profitability and narrowing our geographic focus. Some of our more notable achievements for 2012 include:

- Realized Adjusted Earnings Per Share ("EPS")[2] growth of 22% over 2011
- Closed the sale of eight additional businesses bringing total sale proceeds close to $1 billion since 2011
- Invested $832 million in our balance sheet by paying down debt and repurchasing stock for a total investment of $1.1 billion since September 2011

This was a year with challenging conditions in many markets. In the U.S., low natural gas and power prices in the Midwest were key drivers of a significant impairment of Dayton Power & Light ("DP&L"). These adverse conditions negatively impacted our stock's performance for 2012. However, we responded to these challenges by taking timely steps to increase efficiency and agility by reducing overhead and restructuring our global operations into six market-oriented strategic business units. By reducing overhead costs, increasing knowledge sharing within our markets and strengthening accountability, AES was not only able to meet the challenges of 2012, but is also better prepared to deliver continued earnings growth in the future.

Philip Odeen, Chairman of the Board (left) and Andrés Gluski, President and Chief Executive Officer

Adjusted Earnings Per Share

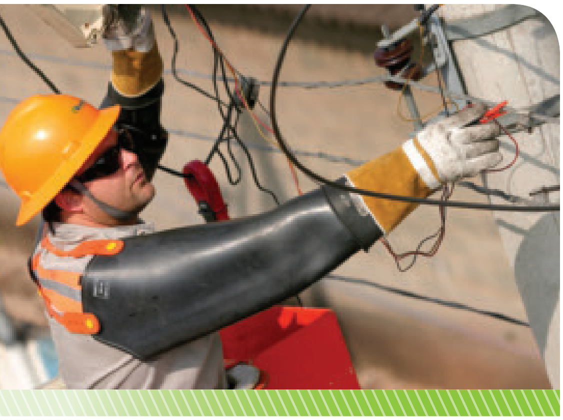
FINANCIAL PERFORMANCE

AES met or exceeded our most important financial and operating targets for 2012, despite confronting the adverse impacts of declining gas and power prices combined with other global economic challenges. Our financial results include:

- Adjusted EPS[2] of $1.24
- Proportional Free Cash Flow[2] of $1,242 million, coming in at the upper end of our guidance range
- Subsidiary distributions of $1,332 million, within our guidance range and at a near record level set in 2011
- Reduced G&A costs by $90 million

Our 2012 financial results benefited from a full year of operations from 1,900 megawatts ("MW") put into service in 2011, as well as improved operations at many of our businesses and better use of corporate synergies and global economies of scale. These benefits and a full year of operations from DP&L

[2]See Financial Notes on Page 5 for definition and reconciliation.



We improve lives by providing safe, reliable and sustainable energy solutions in every market we serve.

in the U.S. helped drive record sales and energy production. Our exceptional operating performance was partially offset by unfavorable foreign currency exchange rates, lower prices from the tariff reset at our AES Eletropaulo distribution business in Brazil, the timing of plant outages in Chile and an increased tax rate.

During 2012, power prices in Ohio declined, compressing margins as customers increasingly moved towards competitive retail electric services. As a result, forecasted profitability and cash flow for DP&L have been reduced and we recognized a non-cash impairment charge of $1.8 billion. While the market and regulatory developments in Ohio and Brazil are challenging, we are proceeding with the actions necessary to meet our financial commitments and achieve world-class operations.

CAPITAL ALLOCATION AND GEOGRAPHIC FOCUS

An important element of the new strategy we adopted in the fourth quarter of 2011 is to optimize our capital allocation and limit our primary growth commitments to markets where we have attractive opportunities for expansions from our existing platform businesses. We aim to balance the use of our available cash between focused growth, strengthening our balance sheet and returning cash to our shareholders. Our overarching goal is to achieve total shareholder returns in excess of our peers. We made important progress towards this goal since implementing our strategy by:

— Repurchasing $390 million of our stock

— Paying a quarterly cash dividend, our first in almost 20 years

— Repaying more than $700 million in consolidated debt

We successfully closed the sale of eight businesses that were not aligned with our long-term strategy. Total sale proceeds to date reached close to $1 billion and we are on track to exit five countries since we first initiated our strategic plan. This includes exiting China, Hungary, the Czech Republic and France, and selling down eighty percent of our position in the Cartagena plant in Spain. We also recently announced the sale of both of our Ukraine distribution businesses and expect to continue to make progress toward narrowing our geographic and business focus throughout the coming year.

Our more focused strategy enabled us to reduce business development spending, which was accompanied by a new and very rigorous investment review process. AES' growth plans are focused on expanding from existing platforms where we have a sustainable competitive advantage. As a result, we are finding lower risk investment opportunities with greater capital efficiency than we achieved in the past. Some of the platform expansions we expect to begin in 2013 include:

— The 532 MW Cochrane coal-fired project in Chile is adjacent to our existing 545 MW coal-fired Angamos facility and we anticipate including a 20 MW battery storage facility

- The Alto Maipo run-of-river hydroelectric project in Chile will utilize some of the existing infrastructure of the Alfalfal hydro facility and will provide the region of Santiago with 531 MW of renewable power
- Indianapolis Power and Light is installing pollution control upgrades to 2,400 MW of its base load coal-fired plants

We continue to believe that narrowing our geographic focus and investing in our platforms better positions us for long-term sustainable earnings growth.

PROFITABILITY

To improve profitability, we took aggressive steps to minimize overhead and strengthen accountability. During 2012 we achieved $90 million in overhead cost savings, significantly exceeding our original target of $50 million. In the fourth quarter of 2012 we identified further efficiencies in our corporate functions and reorganized our business operations into six strategic business units. These changes are expected to increase our total annual overhead savings to $145 million by 2014.

We continue to drive our operational performance to the highest levels and focus on operating in a safe and sustainable manner. Our success in this regard is evidenced by the more than 100 awards and recognitions that AES businesses garnered in 2012, including being ranked among the 20 model companies for sustainability in Brazil, best place to work rankings in the Dominican Republic and Panama, and numerous safety and operational awards from Chivor in Colombia to our Kilroot and Ballylumford plants in the United Kingdom.

Our goal is for AES to be a low-cost administrator of a portfolio of international assets, extracting significant value from its scale and synergies while achieving world-class operations. In the long run, we believe this strategy and our capabilities will greatly benefit our company and all of our stakeholders.

AES VALUES

We are, and always will be, a values-driven company. Safety, integrity, honoring commitments, pursuing excellence and having fun through work are the foundation of everything we do.

The commitment to our shared values continues to differentiate AES in the global marketplace. In the past, AES people were recognized for crisis relief efforts when earthquakes struck Haiti and Chile. In the U.S. in 2012, the Edison Electric Institute ("EEI") awarded AES for our efforts to restore power outside our service territories in response to Superstorm Sandy and other emergency situations in the Midwest. We received some of our industry's highest honors in 2012, including:

- Our Angamos project in Chile received "Power Plant of the Year" by *Power Magazine* and also won our industry's most prestigious award, the EEI "International Edison Award"

Our growth plans are focused on expanding from existing platforms where we have a sustainable competitive advantage.

Our values are the foundation of everything we do, they set us apart from others in our industry.

— AES Laurel Mountain won the 2012 "Excellence in Renewable Energy" Award for Wind Project of the Year at the Renewable Energy World Conference

Our Laurel Mountain project in West Virginia uses lithium-ion battery storage to enhance dispatch and grid stability while Angamos incorporates state-of-the-art environmental impact mitigation techniques. While we continue to have a positive impact on the communities we serve, we are also looking for and finding innovative ways to deliver sustainable energy solutions.

Education, health and the well-being of those in our communities are of special interest to AES people. Many of our programs have been publicly recognized by third parties, such as the Organization of American States' Trust for the Americas. Some of the more notable programs are:

— AES and Trust for the Americas, in a joint program, provide vocational training and employment opportunities for young people in Latin America

— In partnership with the Technical Education and Skills Development Authority in the Philippines, we've established the Masinloc Community-Based Livelihood and Skills Training Center

— Our Energia Verde program is developing a sustainable reforestation program in Panama

We are also proactively investing in long-term programs that educate hundreds of thousands of children in Brazil, Cameroon, Argentina, El Salvador and the U.S. about how to safely manage electricity.

OUTLOOK FOR OUR FUTURE

The transformation of AES is well underway and we are moving forward from a much stronger base to meet the challenges and opportunities we face in our markets. By taking aggressive action to sell non-strategic assets and moving to a more agile and efficient organization, AES has become more focused and more adaptable to the world's changing energy needs. We will continue to extend our platforms by pursuing projects in markets where we have a sustainable competitive advantage and will continue to optimize capital allocation, including returning cash to shareholders.

We look forward to continuing to execute on our plan and we remain confident in our success as we look to 2013 and beyond.

Philip a Odeen

Philip Odeen
Chairman of the Board
March 1, 2013

A. Gluski

Andrés Gluski
President and Chief Executive Officer
March 1, 2013

FINANCIAL NOTES: NON-GAAP FINANCIAL MEASURES RECONCILIATION (UNAUDITED)

($ in millions, except per share amounts)	Year Ended December 31, 2012	2011
Reconciliation of Adjusted Earnings Per Share [1]		
GAAP Diluted EPS from Continuing Operations	$ (1.21)	$ 0.63
Adjustment to Diluted Shares	0.01	—
Non GAAP Diluted EPS from Continuing Operations	(1.20)	0.63
Unrealized Derivative Losses [3]	0.11	0.01
Unrealized Foreign Currency Transaction (Gains) / Losses [4]	(0.03)	0.05
Disposition / Acquisition (Gains)	(0.18)[5]	—
Impairment Losses	2.53[6]	0.29[7]
Debt Retirement Losses	0.01[8]	0.04[9]
Adjusted Earnings Per Share [1]	**$ 1.24**	**$ 1.02**
Reconciliation of Adjusted Pre-Tax Contribution [2]		
Income (Loss) from Continuing Operations Attributable to AES	$ (915)	$ 492
Add: Income Tax Expense from Continuing Operations Attributable to AES	446	220
Pre-Tax Contribution	(469)	712
Adjustments (Net of Noncontrolling Interests):		
Unrealized Derivative Losses [3]	118	11
Unrealized Foreign Currency Transaction (Gains) / Losses [4]	(18)	38
Disposition / Acquisition (Gains)	(206)[5]	—
Impairment Losses	1,936[6]	271[7]
Debt Retirement Losses	16[8]	46[9]
Adjusted Pre-Tax Contribution [2]	**$ 1,377**	**$ 1,078**
Calculation of Maintenance Capital Expenditures for Free Cash Flow [10] Reconciliation Below:		
Maintenance Capital Expenditures	$ 968	$ 889
Environmental Capital Expenditures	75	82
Growth Capital Expenditures	1,227	1,490
Total Capital Expenditures	**$ 2,270**	**$ 2,461**
Reconciliation of Proportional Operating Cash Flow [11]		
Consolidated Operating Cash Flow	$ 2,901	$ 2,884
Less: Proportional Adjustment Factor	966	1,312
Proportional Operating Cash Flow [11]	**$ 1,935**	**$ 1,572**
Reconciliation of Free Cash Flow [10]		
Consolidated Operating Cash Flow	$ 2,901	$ 2,884
Less: Maintenance Capital Expenditures, net of reinsurance proceeds	923	878
Less: Environmental Capital Expenditures	75	82
Free Cash Flow [10]	**$ 1,903**	**$ 1,924**
Reconciliation of Proportional Free Cash Flow [10],[11]		
Proportional Operating Cash Flow	$ 1,935	$ 1,572
Less: Proportional Maintenance Capital Expenditures, net of reinsurance proceeds and Environmental Capital Expenditures	693	640
Proportional Free Cash Flow [10],[11]	**$ 1,242**	**$ 932**

(1) We define adjusted earnings per share ("adjusted EPS"), a non-GAAP measure, as diluted earnings per share from continuing operations excluding gains or losses of the consolidated entity due to (a) unrealized gains or losses 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 unrealized gains or losses related to derivative transactions, unrealized foreign 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) We define adjusted pre-tax contribution ("adjusted PTC"), a non-GAAP measure, as pre-tax income from continuing operations attributable to AES excluding gains or losses of the consolidated entity due to (a) unrealized gains or losses 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. Adjusted PTC also includes net equity in earnings of affiliates on an after-tax basis. The GAAP measure most comparable to adjusted PTC is income from continuing operations attributable to AES. We believe that adjusted PTC 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 unrealized gains or losses related to derivative transactions, unrealized foreign 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. In addition, for adjusted PTC, earnings before tax represents the business performance of the Company before the application of statutory income tax rates and tax adjustments, including the effects of tax planning, corresponding to the various jurisdictions in which the Company operates. Adjusted PTC should not be construed as an alternative to income from continuing operations attributable to AES, which is determined in accordance with GAAP.

(3) Unrealized derivative losses were net of income tax per share of $0.04 and $0.01 in 2012 and 2011, respectively.

(4) Unrealized foreign currency transaction (gains) losses were net of income tax per share of $0.00 and $0.00 in 2012 and 2011, respectively.

(5) Amount primarily relates to the gains from the sale of 80% of our interest in Cartagena for $178 million ($109 million, or $0.14 per share, net of income tax of $0.09 per share) and equity method investments in China of $24 million ($25 million, or $0.03 per share, including an income tax credit of $1 million, or $0.00 per share).

(6) Amount primarily relates to the goodwill impairment at DPL of $1.82 billion ($1.82 billion, or $2.39 per share, net of income tax of $0.00 per share). Amount also includes other-than-temporary impairment of equity method investments in China of $32 million ($32 million, or $0.04 per share, net of income tax of $0.00 per share), and at InnoVent of $17 million ($17 million, or $0.02 per share, net of income tax of $0.00 per share), as well as asset impairments of wind turbines and projects of $41 million ($26 million, or $0.03 per share, net of income tax of $0.02 per share), at Kelanitissa of $19 million ($17 million, or $0.02 per share, net of noncontrolling interest of $2 million and of income tax of $0.00 per share), and at St. Patrick of $11 million ($11 million, or $0.01 per share, net of income tax of $0.00 per share).

(7) Amount includes other-than-temporary impairment of equity method investments at Chigen, including Yangcheng, of $79 million ($79 million, or $0.10 per share, net of income tax of $0.00 per share), asset impairments of wind turbines of $116 million ($75 million, or $0.10 per share, net of income tax of $0.05 per share), Kelanitissa of $42 million ($38 million, or $0.05 per share, net of noncontrolling interest of $4 million and of income tax of $0.00 per share), Bohemia of $9 million ($9 million, and $0.01 per share, net of income tax of $0.00 per share), and goodwill impairment at Chigen of $17 million ($17 million or $0.02 per share, net of income tax of $0.00 per share).

(8) Amount primarily relates to the loss on retirement of debt at the Parent Company of $15 million ($10 million, or $0.01 per share, net of income tax of $0.01 per share).

(9) Amount includes loss on retirement of debt at Gener of $38 million ($22 million, or $0.03 per share, net of noncontrolling interest of $11 million and of income tax of $0.01 per share) and at IPL of $15 million ($10 million, or $0.01 per share, net of income tax of $0.01 per share).

(10) 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.

(11) 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, 2012

-OR-

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

COMMISSION FILE NUMBER 1-12291

AES
we are the energy

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 29, 2012, the last business day of the Registrant's most recently completed second fiscal quarter (based on the closing sale price of $12.73 of the Registrant's Common Stock, as reported by the New York Stock Exchange on such date) was approximately $7.94 billion.

The number of shares outstanding of the Registrant's Common Stock, par value $0.01 per share, on February 20, 2013, was 745,763,563.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Registrant's Proxy Statement for its 2013 annual meeting of stockholders are incorporated by reference in Parts II and III

THE AES CORPORATION

FISCAL YEAR 2012 FORM 10-K
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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 new facilities, whether greenfield, brownfield or investments in the expansion of existing facilities;
- 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 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.

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 diversified power generation and utility company organized into six market-oriented Strategic Business Units ("SBUs"): US (United States), Andes (Chile, Colombia, and Argentina), Brazil, MCAC (Mexico, Central America and Caribbean), EMEA (Europe, Middle East and Africa), and Asia. We were incorporated in 1981.

Item 1.—*Business*. is an outline of our strategy and our businesses by SBU, including key financial drivers. Additional drivers that may have an impact on our businesses are discussed in Item 1A. – *Risk Factors* and Item 3.—*Legal Proceedings*.

Strategy

Our strategic plan intends to maximize the risk-adjusted value of our portfolio for shareholders through our efforts to execute upon the following objectives:

- First, we are managing our portfolio of generation and utility businesses to create value for our stakeholders, including customers and shareholders, through safe, reliable, and sustainable operations and effective cost management.
- Second, we are driving our operating business to manage capital more effectively and to increase the amount of discretionary cash available for deployment into debt repayment, growth investments, shareholder dividends, and share buybacks.
- Third, we are realigning our geographic focus. To this end, we will continue to exit markets where we do not have a competitive advantage or where we are unable to earn a fair risk-adjusted return relative to monetization alternatives. In addition, we will focus our growth investments on platform expansions or opportunities to expand our existing operations.
- Finally, we are working to reduce the cash flow and earnings volatility of our businesses by proactively managing our currency, commodity and political risk exposures, mostly through contractual and regulatory mechanisms, as well as commercial hedging activities. We also will continue to limit our risk by utilizing non-recourse project financing for the majority of our businesses.

Business Lines & Strategic Business Units

Within our six SBUs, as discussed above, we have two lines of business. The first business line is generation, where we own and/or operate power plants to generate and sell power to customers, such as utilities, industrial users, and other intermediaries. The second business line is utilities, where we own and/or operate utilities to generate or purchase, distribute, transmit and sell electricity to end-user customers in the residential, commercial, industrial and governmental sectors within a defined service area. In certain circumstances, our utilities also generate and sell electricity on the wholesale market.

The following table summarizes our generation business by capacity and facilities and our utilities business by customers, capacity and facilities for each SBU.

SBU	Generation Capacity (Gross MW)	Generation Facilities	Utility Customers	Utility GWh	Utility Businesses
US					
Generation	6,281	21			
Utilities	7,517	18	1.1 million	31,777	2
Andes					
Generation	7,740	30			
Brazil					
Generation	3,298	13			
Utilities			7.7 million	54,408	2
MCAC					
Generation	3,860	16			
Utilities			1.2 million	3,642	4
EMEA					
Generation	8,460	22			
Utilities	936	11	2.2 million	11,235	4
Asia					
Generation	1,337	4			
	39,429 [1]	135	12.2 million	101,062	12

(1) 30,251 proportional MW. Proportional MW is equal to gross MW times AES' equity ownership percentage.

Generation

We currently own and/or operate a generation portfolio of approximately 31,000 MW, excluding the generation capabilities of our integrated utilities. Our generation fleet is diversified by fuel type. As a percentage of installed capacity, coal and natural gas each account for 36% and 35%, respectively, of our generating capacity. Renewables, primarily hydro, wind and solar, represent 25% of our generating capacity and oil, diesel and petroleum coke comprise the rest.

Performance drivers of our generation businesses include types of electricity sales agreements, plant reliability and flexibility, fuel costs, fixed-cost management, sourcing and competition.

Electricity Sales Contracts

Our generation businesses sell electricity under medium—or long-term contracts ("contract sales") or under short-term agreements in competitive markets ("short-term sales").

Contract Sales. Most of our generation fleet sells electricity under medium—or long-term contracts. Our contract sales have a term of at least 2 years, but the majority of our contracts are much longer in duration, from 5 to 25 years. Our generation businesses use two contracting strategies, a single contract strategy and a portfolio contract strategy.

Single contracts generally have terms of 10 to 25 years with either a regulated or large industrial unregulated customer. Under these contracts, our generation businesses recover variable costs including fuel and variable operations and maintenance ("O&M") costs, either through contractual pass-throughs or tolling arrangements (see discussion under "Fuel Costs"). These contracts are intended to reduce exposure to the volatility of fuel prices and electricity prices by linking the business's revenues and costs. These contracts also help us to fund a significant portion of the total capital cost of the project through long-term non-recourse project-level financing. Our generation businesses in the United States, Bulgaria, and Vietnam are some examples of where we have used the single-contract approach.

Some of our businesses utilize a portfolio contract strategy. Under this approach, the business sells its output to several different customers with the aim of contracting a significant portion of total output and we generally contract for a period of 2 to 10 years with a regulated customer (utility, municipal or cooperative) or unregulated free client (a customer that is allowed under the local regulatory regime to contract directly for its electricity needs). These contracts typically include a direct or indexation-based fuel pass-through. When the contract does not include a fuel pass-through, we typically hedge fuel costs or enter into fuel supply agreements for a similar contract period (see discussion under "Fuel Costs"). Examples of businesses with the portfolio contract strategy include AES Gener in Chile and Masinloc in the Philippines.

Capacity Payments and Contract Sales. Most of our contract sales include a capacity payment that covers projected fixed costs of the plant, including fixed O&M expenses and a return on capital invested. In addition, most of our contracts require that the majority of the capacity payment be denominated in the currency matching our fixed costs, including debt and return on capital invested. Although our project debt may consist of both fixed and floating rate debt, we typically hedge a significant portion of our exposure to variable interest rates. For foreign exchange, we generally structure the revenue of the business to match the currency of the debt and fixed costs.

Thus, these contracts, or other commercial arrangements that we have made around or in addition to these contracts, significantly mitigate our exposure to changes in power and fuel prices, currency fluctuations and changes in interest rates. In addition, these contracts generally provide for a recovery of our fixed operating expenses and a return on our investment, as long as we operate the plant to the reliability standards required in the contract. This important risk mitigation helps to limit the variability of the earnings and cash flows of the business.

Short-Term Sales. Our other generation businesses sell power and ancillary services under short-term contracts with a term of 2 years or less, including spot sales, directly in the short-term market, or, in some cases, at regulated prices. The short-term markets are typically administered by a system operator to coordinate dispatch. Short-term markets generally operate on merit order dispatch, where the least expensive generation facilities, based upon variable cost, are dispatched first and the most expensive facilities are dispatched last. The short-term price is typically set at the marginal cost of energy or bid price (the cost of the last plant required to meet system demand). As a result, the cash flows and earnings associated with these businesses are more sensitive to fluctuations in the market price for electricity. In addition, many of these wholesale markets include markets for ancillary services to support the reliable operation of the transmission system. Across our portfolio, we provide a wide array of ancillary services, including voltage support, frequency regulation and spinning reserves. An example of a business with short-term sales is our Kilroot facility in the United Kingdom.

Capacity Payments and Short-Term Sales. Many of the markets in which we operate include regulated capacity markets. These capacity markets are intended to provide additional revenue based upon availability without reliance on the energy margin from the merit order dispatch. Capacity markets are typically priced based on the cost of a new entrant and the system capacity relative to the desired level of reserve margin (generation available in excess of peak demand). Our generating facilities selling in the short-term market typically receive capacity payments based on their availability in the market.

Plant Reliability and Flexibility

Our contract and short-term sales provide incentives to our generation plants to optimally manage availability, operating efficiency and flexibility. Capacity payments under the single contract strategy are tied to meeting minimum standards. In short-term sales, our plants must be reliable and flexible to capture peak market prices and to maximize market-based revenues. In addition, our flexibility allows us to capture ancillary service revenue, meeting local market needs.

Fuel Costs

For our thermal generation plants, fuel is a significant component of our total cost of generation. For contract sales, we often enter into fuel supply agreements to match the contract period, or we may hedge our fuel costs. Some of our contracts have periodic adjustments for changes in fuel cost indices. In those cases, we have fuel supply agreements with shorter terms to match those adjustments. For certain projects using the single contract strategy, we have tolling arrangements where the power offtaker is responsible for the supply and cost of fuel to our plants.

In short-term sales, we sell power at market prices that are generally reflective of the market cost of fuel at the time, and thus procure fuel supply on a short-term basis, generally designed to match up with our market sales profile. Since fuel price is often the primary determinant for power prices, the economics of projects with short-term sales are often subject to volatility of relative fuel prices.

About one-third of our generation fleet is coal-fired. In the United States, most of our plants are supplied from domestic coal. At our non-U.S. generation plants and at our plant in Hawaii, we source coal internationally. Across our fleet, we utilize our global sourcing program to maximize the purchasing power of our fuel procurement.

Roughly one-third of our generation plants are fueled by natural gas. Generally, we use gas from local supplies in each market. A few exceptions to this are AES Gener in Chile, our Uruguaiana plant in Brazil, which resumed operations in February 2013, and the Dominican Republic, where we import Liquefied Natural Gas ("LNG") to utilize in the local market.

Approximately five percent of our generation fleet utilizes oil, diesel and petroleum coke ("pet coke") for fuel. Oil and diesel are sourced locally at prices indexed to international markets, while pet coke is largely sourced from Mexico and the U.S. The remaining portion of our portfolio is comprised mostly of hydro, wind and solar generation plants, which do not have significant fuel costs.

Fixed-Cost Management

In our businesses with long-term contracts, the majority of the fixed operating and maintenance costs are recovered through the capacity payment. However, for all generation businesses, managing fixed costs and reducing them over time is a driver of business performance.

Competition

For our businesses with medium—or long-term contracts, there is limited competition during the term of the contract. For short-term sales, plant dispatch and the price of electricity is determined by market competition and local dispatch and reliability rules.

Utilities

AES' 12 utility businesses distribute power to more than 12 million people in six countries. These businesses also include generation capacity totaling approximately 8,500 MW. These businesses have a variety of structures, ranging from integrated utility to pure transmission and distribution businesses.

In general, our utilities sell electricity directly to end-users, such as homes and businesses, and bill customers directly. Key performance drivers for utilities include the regulated rate of return and tariff, seasonality, weather variations, economic activity, reliability of service and competition.

Regulated Rate of Return and Tariff

In exchange for the exclusive right to sell or distribute electricity in a franchise area, our utility businesses are subject to government regulation. This regulation sets the prices ("tariffs") that our utilities are allowed to charge retail customers for electricity and establishes service standards that we are required to meet.

Our utilities are generally permitted to earn a regulated rate of return on assets, determined by the regulator based on the utility's allowed regulatory asset base, capital structure and cost of capital. The asset base on which the utility is permitted a return is determined by the regulator and is based on the amount of assets that are considered used and useful in serving customers. Both the allowed return and the asset base are important components of the utility's earning power. The allowed rate of return and operating expenses deemed reasonable by the regulator are recovered through the regulated tariff that the utility charges to its customers.

The tariff may be reviewed and reset by the regulator from time to time depending on local regulations, or the utility may seek a change in its tariffs. The tariff is generally based upon a certain usage level and may include a pass-through to the customer of costs that are not controlled by the utility, such as the costs of fuel (in the case of integrated utilities) and/or the costs of purchased energy. In addition to fuel and purchased energy, other types of costs may be passed through to customers via an existing mechanism, such as certain environmental expenditures that are covered under an environmental tracker at our utility in Indiana, Indianapolis Power & Light Company ("IPL"). Components of the tariff that are directly passed through to the customer are usually adjusted through a summary regulatory process or an existing formula-based mechanism. 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 unregulated in some regulatory regimes 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 its distribution system.

The regulated tariff generally recognizes that our utility businesses should recover certain operating and fixed costs, as well as manage uncollectible amounts, quality of service and non-technical losses. Utilities therefore need to manage costs to the levels reflected in the tariff or risk non-recovery of costs or diminished returns.

Seasonality, Weather Variations and Economic Activity

Our utility businesses are affected by seasonal weather patterns throughout the year and, therefore, the operating revenues and associated operating expenses are not generated evenly by month during the year. Additionally, weather variations may also have an impact based on the number of customers, temperature variances from normal conditions and customers' historic usage levels and patterns. The retail kilowatt hours ("kWh") sales, after adjustments for weather variations, are affected by changes in local economic activity, energy efficiency initiatives, as well as the number of retail customers.

Reliability of Service

Our utility businesses must meet certain reliability standards, such as duration and frequency of outages. Those standards may be specific with incentives or penalties for performance against these standards. In other cases, the standards are implicit and the utility must operate to meet customer expectations.

Competition

Our integrated utilities, such as IPL and The Dayton Power & Light Company ("DP&L"), operate as the sole distributor of electricity within their respective jurisdictions. Our businesses own and operate all of the businesses and facilities necessary to generate, transmit and distribute electricity. Competition in the regulated electric business is primarily from the on-site generation of industrial customers; however, in Ohio, our native load customers have the ability to switch to alternative suppliers for their generation service. Our integrated utilities, particularly DP&L, are exposed to the volatility in wholesale prices to the extent our generating capacity exceeds the native load served under the regulated tariff and short-term contracts. See the full discussion under the US SBU.

At our pure transmission and distribution businesses, such as those in Brazil and El Salvador, we face relatively limited competition due to significant barriers to entry. At many of these businesses, large customers, as defined by the relevant regulator, can leave and choose to return to regulated service.

Development and Construction

We develop and construct new generation facilities. For our utility businesses, new plants may be built in response to customer needs or to comply with regulatory developments and are developed subject to regulatory approval that permits recovery of our capital cost and a return on our investment. For our generation businesses, our priority for development is platform expansion opportunities, where we can add on to our existing facilities in our key platform markets where we have a competitive advantage. We make the decision to invest in new projects by evaluating the project returns and financial profile against a fair risk-adjusted return for the investment and against alternative uses of capital, including corporate debt repayment and share buybacks.

In some cases, we enter into long-term contracts for output from new facilities prior to commencing construction. To limit required equity contributions from The AES Corporation, we also seek non-recourse project debt financing and other sources of capital, including partners where it is commercially attractive. For construction, we typically contract with a third party to manage the construction, although our construction management team supervises the construction work to ensure that the project is completed within budget and meets the required safety, efficiency and productivity standards.

Environmental Matters

We are subject to various international, federal, state, and/or local regulations in all of our markets. These regulations 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.

We are also subject to various federal, state, regional and local environmental protection and health and safety laws and regulations governing, among other things, the generation, storage, handling, use, disposal and transportation of hazardous materials; the emission and discharge of hazardous and other materials into the environment; and the health and safety of our employees. These laws and regulations often require a lengthy and complex process of obtaining and renewing permits and other governmental authorizations from federal, state and local agencies. Violation of these laws, regulations or permits can result in substantial fines, other sanctions, suspension or revocation of permits and/or facility shutdowns. See later in Item 1.—*Business and Environmental and Land Use Regulations* for further regulatory and environmental discussion.

Renewables and Other Initiatives

In recent years, as demand for renewable sources of energy has grown, we have also been developing and/or acquiring hydro, wind, and solar based renewable projects. Currently, we own interests in 9,691 MW (5,216 proportional MW) of renewable projects, including projects in operations and under construction. Currently, the majority of our renewable capacity is hydro-based, representing 84% of our renewable portfolio.

In 2005, we started investing in wind generation businesses and currently have 1,518 MW in operation. In addition, we have 36 MW under construction.

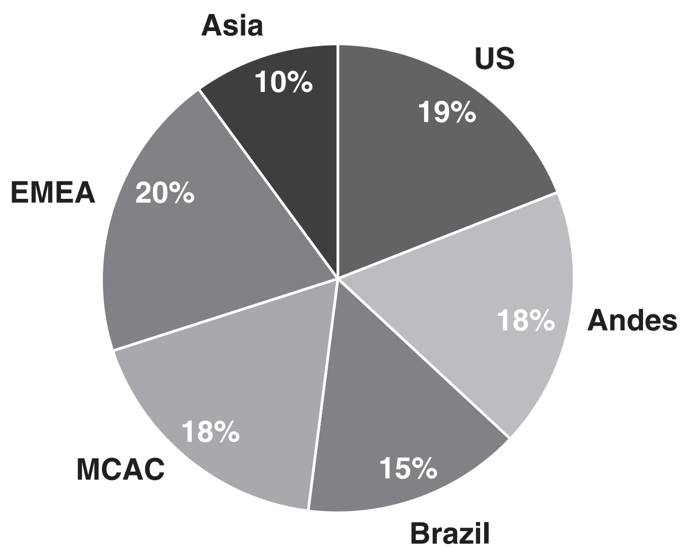
In 2008, we formed a 50/50 joint venture with Riverstone to develop, own and operate solar installations. Since its launch, AES Solar has commenced commercial operations of 256 MW of solar projects in Bulgaria, France, Greece, India, Italy, Puerto Rico and Spain, and has 266 MW under construction in Bulgaria, France, Greece, India, Italy and the U.S.

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.

Strategic Business Units

AES operates and manages its six SBUs under one Chief Operating Officer ("COO"). All SBUs include generation facilities and four include utility businesses. The Company measures the operating performance of its SBUs using adjusted pre-tax contribution ("adjusted PTC"), a non-GAAP measure (see definition below).

AES' primary sources of revenue, gross margin and adjusted PTC are from generation and utilities businesses. The contribution to adjusted PTC by SBU for the year ended December 31, 2012 is shown below. The percentages shown are the contribution by each SBU to gross adjusted PTC, i.e. the total adjusted PTC by SBU, before deductions for Corporate. See Item 8.—*Financial Statements and Supplementary Data* for reconciliation.



We define Adjusted PTC as pre-tax income from continuing operations attributable to AES excluding gains or losses of the consolidated entity due to (a) unrealized gains or losses 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. Adjusted PTC also includes net equity in earnings of affiliates on an after-tax basis. Adjusted PTC in each SBU includes the effect of intercompany transactions with other SBUs other than interest and charges for certain management services.

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

The management reporting structure is organized along the six SBUs – led by our COO, who in turn reports to our Chief Executive Officer ("CEO"). Our CEO and COO are based in Arlington, Virginia. During the fourth quarter of 2012, the Company completed the restructuring of its operational management and reporting process into these six SBUs. For financial reporting purposes, the Company has identified eight reportable segments based on the six SBUs, which include:

- US SBU
  - US—Generation segment
  - US—Utilities segment
- Andes SBU
  - Andes—Generation segment
- Brazil SBU
  - Brazil—Generation segment
  - Brazil—Utilities segment
- MCAC SBU
  - MCAC—Generation segment
- EMEA SBU
  - EMEA—Generation segment
- Asia SBU
  - Asia—Generation segment

Corporate and Other—For financial reporting purposes the Company's EMEA and MCAC utilities as well as Corporate 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* and Note 17—*Segment and Geographic Information* included in Item 8.—*Financial Statements and Supplementary Data* for further discussion of the Company's segment structure used for financial reporting purposes.

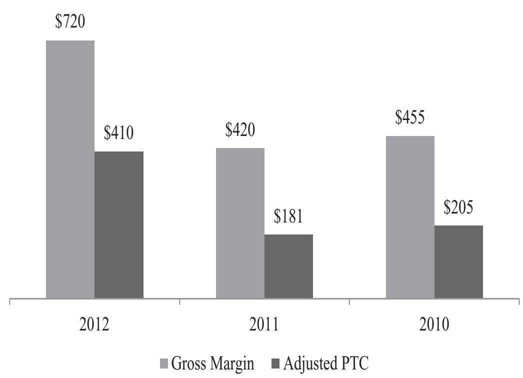
AES Solar and certain other unconsolidated businesses are accounted for using the equity method of accounting. Therefore, their operating results are included in "Net Equity in Earnings of Affiliates" on the face of the Consolidated Statements of Operations, not in revenue and gross margin.

"Corporate and Other" also includes costs related to corporate overhead which are not directly associated with the operations of our eight reportable segments and other intercompany charges such as self-insurance premiums which are fully eliminated in consolidation. See Note 17—*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 PTC (a non-GAAP measure) and total assets by segment.

The following describes our businesses within our six SBUs:

US SBU

Our US SBU has 21 generation facilities and two integrated utilities in the United States. Our US operations accounted for 20%, 10% and 12% of consolidated AES gross margin and 19%, 10% and 13% of consolidated AES adjusted PTC (a non-GAAP measure) in 2012, 2011 and 2010, respectively. The percentages shown are the contribution by each SBU to gross adjusted PTC, i.e. the total adjusted PTC by SBU, before deductions for Corporate.



The following table provides highlights of our U.S. operations:

Generation Capacity	13,798 gross MW (13,664 proportional MW)
Utilities Penetration	1,107,000 customers (31,777 GWh)
Generation Facilities	21
Utility Businesses	2 integrated utilities (includes 18 generation plants)
Key Generation Businesses	Southland and Hawaii
Key Utility Businesses	IPL and DPL

Operating installed capacity of our US SBU totals 13,798 MW, of which 29%, 28%, 27% and 16%, is located at our Southland, DPL, IPL, and additional U.S. generation facilities, respectively. IPL's parent, IPALCO Enterprises, Inc., and DPL Inc. are SEC registrants, and as such, follow public filing requirements of the Securities Exchange Act of 1934. Set forth in the table below is a list of our U.S. businesses:

Business	Location	Fuel	Gross MW	AES Equity Ownership (Percent, Rounded)	Year Acquired or Began Operation
Southland—Alamitos	US—CA	Gas	2,075	100%	1998
Southland—Redondo Beach	US—CA	Gas	1,392	100%	1998
Southland—Huntington Beach	US—CA	Gas	474	100%	1998
Shady Point	US—OK	Coal	360	100%	1991
Buffalo Gap II[1]	US—TX	Wind	233	100%	2007
Hawaii	US—HI	Coal	208	100%	1992
Warrior Run	US—MD	Coal	205	100%	2000
Buffalo Gap III[1]	US—TX	Wind	170	100%	2008
Deepwater	US—TX	Pet Coke	160	100%	1986
Wind Generation Facilities[2]	US	Wind	134	0%	2005
Beaver Valley	US—PA	Coal	132	100%	1985
Buffalo Gap I[1]	US—TX	Wind	121	100%	2006
Lake Benton I[1]	US—MN	Wind	106	100%	2007
Armenia Mountain[1]	US—PA	Wind	101	100%	2009
Laurel Mountain	US—WV	Wind	98	100%	2011
Storm Lake II[1]	US—IA	Wind	78	100%	2007
Mountain View I & II[1]	US—CA	Wind	67	100%	2008
Condon[1]	US—CA	Wind	50	100%	2005
Mountain View IV	US—CA	Wind	49	100%	2012
Tehachapi	US—CA	Wind	38	100%	2006
Palm Springs	US—CA	Wind	30	100%	2005
			6,281		

(1) 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 Non-Controlling Interest in the Company's Consolidated Balance Sheet.

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

Set forth in the tables below is a list of our U.S. utilities and their generation facilities:

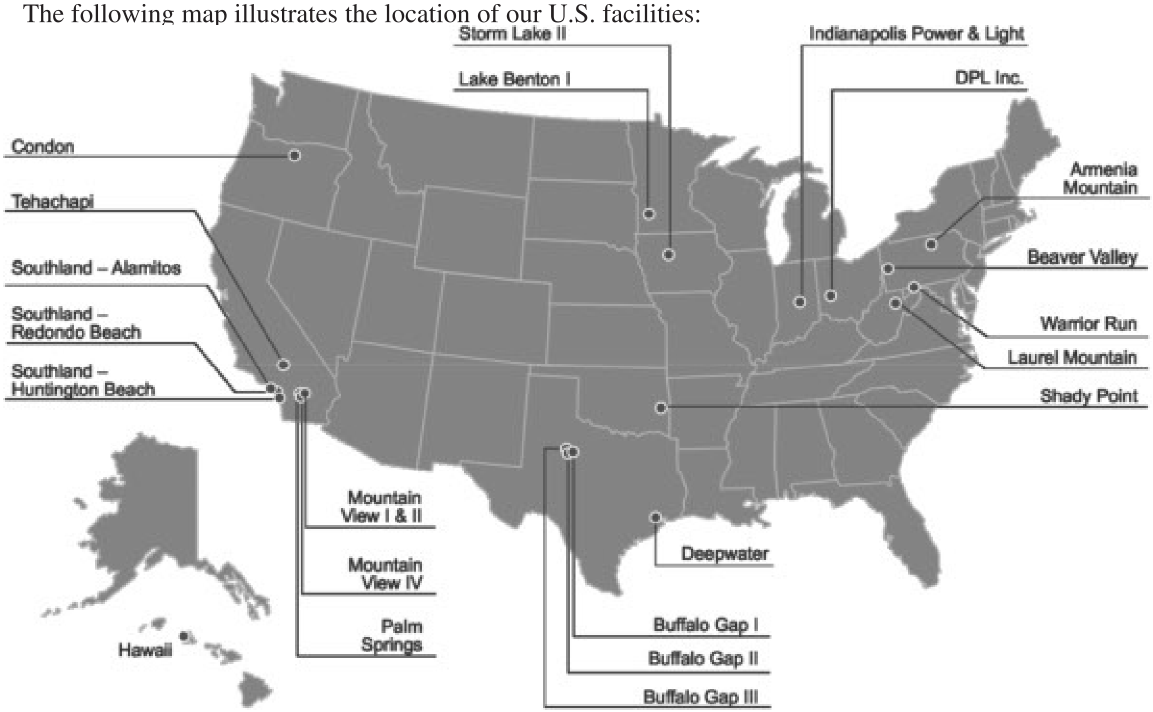
Business	Location	Approximate Number of Customers Served as of 12/31/2012	GWh Sold in 2012	AES Equity Interest (Percent, Rounded)	Year Acquired
DP&L	US—OH	637,000	16,454	100%	2011
IPL	US—IN	470,000	15,323	100%	2001
		1,107,000	31,777		

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
DP&L[(1)]	US—OH	Coal/Diesel/Solar	3,818	100%	2011
IPL[(2)]	US—IN	Coal/Gas/Oil	3,699	100%	2001
			7,517		

(1) 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 Energy, LLC plants: Tait Units 4-7 and Montpelier Units 1-4.

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

The following map illustrates the location of our U.S. facilities:



US SBU Businesses

U.S. Utilities

IPALCO

Business Description. IPALCO owns all of the outstanding common stock of IPL. IPL is engaged primarily in generating, transmitting, distributing and selling electric energy to approximately 470,000 customers in the city of Indianapolis and neighboring areas within the state of Indiana. IPL has an exclusive right to provide electric service to those customers. IPL's service area covers about 528 square miles with a population of approximately 911,000. IPL owns and operates four generating stations. Two of the generating stations are primarily coal-fired. The third station has a combination of units that use coal (baseload 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. IPL's net electric generation capacity for winter is 3,492 MW and net summer capacity is 3,353 MW.

Market Structure. IPL is one of many transmission system owner members in the Midwest Independent Transmission System Operator, Inc. ("MISO"). MISO is a regional transmission organization which maintains functional control over the combined transmission systems of its members and manages one of the largest energy and ancillary services markets in the U.S. IPL offers the available electricity production of each of its generation assets into the MISO day-ahead and real-time markets. MISO operates on a merit order dispatch, considering transmission constraints and other reliability issues to meet the total demand in the MISO region.

Regulatory Framework

Retail Ratemaking. In addition to the regulations referred to below in "U.S. Regulatory Matters", IPL is subject to regulation by the Indiana Utility Regulatory Commission ("IURC") with respect to: IPL's services and facilities; retail rates and charges; the issuance of long-term securities; and certain other matters. The regulatory power of the IURC over IPL's business is both comprehensive and typical of the traditional form of regulation generally imposed by state public utility commissions. IPL's tariff rates for electric service to retail customers consist of basic rates and charges, which are set and approved by the IURC after public hearings. The IURC gives consideration to all allowable costs for ratemaking purposes including a fair return on the fair value of the utility property used and useful in providing service to customers. In addition, IPL's rates include various adjustment mechanisms including, but not limited to, those to reflect changes in fuel costs to generate electricity or purchased power prices, referred to as Fuel Adjustment Charges ("FAC") and for the timely recovery of costs incurred to comply with environmental laws and regulations referred to as Environmental Compliance Cost Recovery Adjustment ("ECCRA"). See Senate Bill 251 discussion under *Other United States Environmental and Land Use Legislation and Regulations* later in this section. These components function somewhat independently of one another, but the overall structure of IPL's rates and charges would be subject to review at the time of any review of IPL's basic rates and charges.

Environmental Matters

Mercury and Air Toxics Standards ("MATS"). IPL management has developed a plan to comply with the MATS rule (discussed below). Most of IPL's coal-fired capacity has acid gas scrubbers or comparable control technologies; however, there are other improvements to these control technologies that are necessary to achieve compliance. IPL was successful in deferring IPL's compliance date to April 16, 2016, based on an extension granted by the Indiana Department of Environmental Management ("IDEM").

IPL has reviewed the impact of the MATS rule and estimate additional expenditures related to this rule for environmental controls for IPL's baseload generating units to be approximately $511 million through 2016 excluding demolition costs. In June 2012, IPL filed a petition and requested a Certificate of Public Convenience and Necessity ("CPCN") to comply with the MATS rule. These filings detail the controls IPL plans to add to each of IPL's five baseload units, including four at IPL's Petersburg generating station and one at IPL's Harding Street generating station. IPL will seek and expect to recover through IPL's environmental rate adjustment mechanism, all operating and capital expenditures related to compliance; however, there can be no assurance that IPL will be successful in that regard. Recovery of these costs is expected through an Indiana statute, which allows for 100% recovery of qualifying costs through a rate adjustment mechanism. Funding for these capital expenditures is expected to be obtained from additional debt financing at IPL; equity contributions from AES; borrowing capacity on IPL's committed credit facilities; and cash generated from operating activities.

National Pollution Discharge Elimination System ("NPDES"). On August 28, 2012, IDEM issued NPDES permits to the IPL Petersburg, Harding Street, and Eagle Valley generating stations, which became effective in October 2012. IPL is conducting studies to determine what operational changes and/or additional equipment will be required to comply with the new limitation. IPL cannot predict the impact of these regulations on IPL's consolidated results of operations, cash flows, or financial condition, but it is expected to be material. Recovery of these costs is expected through an Indiana statute, which allows for 80% recovery of qualifying costs through a rate adjustment mechanism with the remainder recorded as a regulatory asset to be considered for recovery in the next basic rate case proceeding; however there can be no assurances that IPL would be successful in that regard. See Water Discharges discussion under *Other United States Environmental and Land Use Legislation and Regulations* for further details of NPDES later in this section.

Replacement Generation. The combination of existing and expected environmental regulations make it likely that IPL will temporarily or permanently retire or repower several of IPL's 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 have made up less than 15% of IPL's net electricity generation over the past five years. IPL is continuing to evaluate available options for replacing this generation, which include modifying one or more of the units to use natural gas as the fuel source, building new units, purchasing existing units, joint ownership of generating units, purchasing electricity and capacity from a third party, or some combination of these options. Accordingly, in June 2012, IPL issued a request for proposals for 600 MW of replacement capacity and energy beginning in June 2017, which is intended to help IPL determine the best plan for replacement generation. Proposals from outside parties have been received and IPL is currently evaluating appropriate next steps. IPL's decision on which replacement options to pursue will be impacted by the ultimate timetable for implementation of the rule. IPL will seek and expect to recover IPL's costs associated with replacing the retired units, but no assurance can be given as to whether the IURC would approve such a request.

Key Financial Drivers

IPL's ability to earn wholesale margin is influenced by wholesale prices for electricity, fuel prices and the availability of their generating assets. Retail demand also influences IPL's financial results. IPL's ability to recover expenses and earn a return on capital expenditures in a timely manner, as well as passage of new legislation or implementation of regulations, has an impact on the business. Local macroeconomic conditions, given that IPL has an exclusive territory, weather and energy efficiency also drive their retail demand.

DPL Inc.

Business Description. DPL is an energy holding company whose principal subsidiaries include DP&L, DPL Energy Resources, Inc. ("DPLER") and DPL Energy, LLC ("DPLE"). DP&L generates, transmits, distributes and sells electricity to more than 513,000 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, peaking generation units, solar generating facilities and numerous transmission facilities. DP&L also has one wholly-owned coal-fired plant, along with several gas-fired peaking plants. DPLER, a competitive retail marketer, sells retail electricity to more than 198,000 retail customers in Ohio and Illinois. Approximately 73,000 of these customers are also distribution customers of DP&L in Ohio. DPLE owns peaking generation units located in Ohio and Indiana. DP&L's wholly-owned plants and their share of the capacity of its jointly-owned plants and DPLE's wholly-owned peaking units aggregate to approximately 3,818 MW.

Market Structure

Customer Switching. 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 Public Utilities Commission of Ohio ("PUCO") maintains jurisdiction over DP&L's delivery of electricity, SSO and other retail electric services. 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). 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 residences.

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, 2012, approximately 30% of customers representing 58% of 2012's overall energy usage (kWh) within DP&L's service area had elected to obtain their supply service from CRES Providers. DPL's subsidiary DPLER is a CRES Provider that has been marketing transmission and generation services to DP&L customers in Ohio and Illinois. During 2012, DPLER accounted for approximately 6,201 million kWh (76%) and other CRES Providers accounted for about 1,981 million kWh (24%) of the total 8,182 million kWh supplied by CRES Providers within DP&L's service territory. The volume supplied by DPLER represents 44% of DP&L's total distribution volume during 2012. 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 material adverse effect on its future results of operations, financial condition and cash flows.

PJM Operations. DP&L is a member of the PJM Interconnection, LLC ("PJM"). PJM is a Regional Transmission Organization ("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. 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. The Reliability Pricing Model ("RPM") is PJM's capacity construct. The purpose of RPM is to enable PJM to obtain sufficient resources to reliably meet the needs of electric customers within the PJM footprint. PJM conducts an auction to establish the price by zone, three years in advance of the delivery year. DP&L's capacity has been located in the rest of the RTO area of PJM.

The PJM RPM auction for the 2015/16 period cleared at a per-MW price of $136/MW-day for DP&L's RTO area. The clearing prices for the periods 2011/12, 2012/13, 2013/14 and 2014/15 were $110/MW-day, $16/MW-day, $28/MW-day and $126/MW-day, respectively, based on previous auctions. Based on the base residual auction prices, DP&L estimates that future gross RPM capacity revenue will be $156 million, $106 million and $28 million for 2015, 2014 and 2013 calendar years, respectively. 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 load congestion as well as PJM's business rules relating to bidding for demand response and energy efficiency resources in the RPM capacity auctions.

Regulatory Framework

Retail Regulation. DP&L is subject to regulation by the PUCO, which regulates its distribution services and facilities, retail rates and charges, reliability of service, compliance with renewable energy portfolio and energy efficiency program requirements and certain other matters. DP&L's rates for electric service to retail customers consist of basic rates and charges that are set and approved by the PUCO after public hearings. In addition, DP&L's rates include various adjustment mechanisms including but not limited to, those to reflect changes in fuel costs to generate electricity or purchased power prices, referred to as FAC and for the timely recovery of costs incurred to comply with alternative energy, renewable, energy efficiency, and economic development costs. These components function somewhat independently of one another, but the overall structure of DP&L's retail rates and charges are subject to the rules and regulations established by the PUCO.

Retail Rate Structure. Retail generation has been deregulated in Ohio since 2001, which allows electric customers within Ohio to choose to purchase retail generation service under contract with CRES Providers. DP&L is required to provide retail generation service to any customer that has not signed a contract with a CRES provider at SSO rates. SSO rates are subject to rules and regulations of the PUCO and are established based on either an Electric Security Plan ("ESP") or Market Rate Offer ("MRO") filing. DP&L's wholesale transmission rates are regulated by the FERC. DP&L's distribution rates are regulated by the PUCO and are established through a traditional tariff rate setting process. DP&L is permitted to recover its costs of providing distribution service as well as earn a regulated rate of return on assets, determined by the regulator, based on the utility's allowed regulated asset base, capital structure and cost of capital.

DP&L filed an ESP with the PUCO in 2012 requesting, among other things, a non-bypassable charge designed to recover $137 million per year for five years from all customers. DP&L also requested approval of a switching tracker that would measure the incremental amount of switching over a base case and defer the lost value into a regulatory asset which would be recovered from all customers beginning in January 2014. The ESP further states that DP&L plans to file on or before December 31, 2013 its plan for legal separation of its generation assets as required by legislation. The ESP proposes a three-year, five-month transition to market, whereby a wholesale competitive bidding structure will be phased in to supply generation service to customers located in DP&L's service territory that have not chosen an alternative generation supplier. The PUCO authorized that DP&L's rates in effect at December 31, 2012 would continue until the new ESP rates go into effect.

Environmental Matters

The EPA promulgated the Clean Air Interstate Rule ("CAIR") to regulate emissions from existing power plants in the eastern U.S. This became known as the Cross-State Air Pollution Rule ("CSAPR") and was vacated by the D. C. Circuit Court. If CSAPR were to be reinstated in its current form, DP&L does not expect any material capital costs for DP&L's plants, which would continue to operate as they currently have scrubbing equipment installed.

In relation to MATS, it is expected that DP&L has several units that are fully owned or jointly-owned that are expected to cease operations as a result of non-compliance with the requirements under MATS. For more information see *Other United States Environmental and Land Use Legislation and Regulations* discussion later in this section.

On January 7, 2013, Ohio EPA issued an NPDES permit for J.M. Stuart Station. DPL is analyzing the NPDES permit at this time. The uncertainties around the type of compliance and the cost that may be necessary to become compliant could be material to DPL. See *Water Discharges* section of *Other United States Environmental and Land Use Legislation and Regulations* later in this section for a further discussion.

Key Financial Drivers

DPL's focus is on completing its current rate proceedings and working with all stakeholders to determine a fair and reasonable outcome, including an appropriate non-bypassable charge. Other key objectives are retaining customers under its regulated tariff and enhancing the competitiveness of its retail business, DPLER, to maintain and gain customers with an adequate margin. DPL's operating performance also varies with wholesale power prices, which are largely influenced by delivered gas prices, as well as movements in local coal prices and long-term capacity prices. Further, total demand for electricity is affected by economic activity, weather and weather-related events, and demand side management and energy efficiency measures. Finally, DPL has refinancing risk related to 2013 debt maturities of $470 million and $300 million of un-drawn credit facilities at DP&L.

See Item 1A.—*Risk Factors* for additional discussion on DPL.

U.S. Generation

Business Description. In the U.S., we own a diversified generation portfolio in terms of geography, technology and fuel source. The principal markets where we are engaged in the generation and supply of electricity (energy and capacity) are the Western Electricity Coordinating Council ("WECC"), PJM, Southwest Power Pool Electric Energy Network ("SPP") and Hawaii. AES Southland, in the WECC, is our most significant generating business.

AES Southland

Business Description. In terms of aggregate installed capacity, AES Southland is one of the largest generation operators in California with an installed capacity of 3,941 MW, accounting for approximately 7% of the state's installed capacity and 16% of the peak demand of Southern California Edison. The three coastal power plants comprising AES Southland are in areas that are critical for local reliability and play an important role integrating the increasing amounts of renewable generation resources in California.

Market Structure. All of AES Southland's capacity is contracted through a long-term agreement, which expires in mid-2018 (the "Tolling Agreement"). Under the Tolling Agreement, AES Southland's largest revenue driver is unit availability, as approximately 95% of its revenue comes from availability-related payments. Historically, AES Southland has generally met or exceeded its contractual availability requirements under the Tolling Agreement and often captures bonuses for exceeding availability requirements in peak periods.

The offtaker under the Tolling Agreement provides gas to the three facilities at no cost; therefore, AES Southland is not exposed to significant fuel price risk. AES Southland does, however, guarantee the efficiency of each unit so that any fuel consumed in excess of what would have been consumed had the guaranteed efficiency been achieved is paid for by AES Southland. Additionally, if the units operate at an efficiency better than the guaranteed efficiency, AES Southland gets credit for the gas that is not consumed. The business is also exposed to the cost of replacement power for a limited time period if any of the plants are dispatched by the offtaker and are not able to meet the required dispatch schedule for generation of electric energy.

AES Southland delivers electricity into the California Independent System Operator's market through its Tolling Agreement counterparty.

Regulatory Framework

Environmental Matters. The California State Water Resources Control Board ("SWRCB") policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (the "Policy") became effective on October 1, 2010 and provides a phased compliance schedule, which requires all AES Southland plants to be compliant by December 31, 2020. The Policy establishes technology-based standards to implement 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. There are two potential tracks to comply with the Policy:

Track 1—Reduce intake flow rate on each unit to a level commensurate with that which can be obtained by a closed-cycle wet cooling system.

Track 2—If they are able to demonstrate that Track 1 is not feasible, the existing power plant must reduce impingement mortality and entrainment of marine life, on a unit-by-unit basis, to a comparable level to that which would be achieved under Track 1, using operational or structural controls, or both.

As required by the Policy, AES Southland submitted its implementation plans by April 1, 2011 and proposed to comply with the Policy by retiring the existing units and replacing them with new units that would not use ocean water provided satisfactory contracts could be obtained to support development and construction of new units. The SWRCB is currently reviewing the implementation plans and has requested additional information to assist with their evaluation. For further discussion of environmental laws and regulations affecting the U.S. businesses, see Environmental and Land Use Regulations later in this section.

Key Financial Drivers

AES Southland's contractual availability is the single most important driver of operations. Its units are generally required to achieve at least 86% availability in each contract year; AES Southland has usually met or exceeded its contractual availability.

Additional U.S. Generation Businesses

Business Description. Additional businesses include thermal and wind generating facilities, of which AES Hawaii and AES Warrior Run are the most significant, and our energy storage line of business.

Many of our U.S. generation plants provide baseload operations and are required to maintain a guaranteed level of availability. Any change in availability has a direct impact on financial performance. The plants are generally eligible for availability bonuses on an annual basis if they meet certain requirements. In addition to plant availability, fuel cost is a key business driver for some of our facilities. AES Hawaii receives a fuel payment from its offtaker, which is based on a fixed rate indexed to the Gross National Product – Implicit Price Deflator ("GNPIPD"). Since the fuel payment is not directly linked to market prices for fuel, the risk arising from fluctuations in market prices for coal is borne by AES Hawaii.

To mitigate the risk from such fluctuations, AES Hawaii has entered into fixed-price coal purchase commitments that end in December 2013; the business could be subject to variability in coal pricing beginning in 2014. To mitigate fuel risk beyond 2013, AES Hawaii plans to seek additional fuel purchase commitments on favorable terms. However, if market prices rise and AES Hawaii is unable to procure coal supply on favorable terms, the financial performance of AES Hawaii could be materially and adversely affected.

AES Warrior Run has a fuel contract with a major global fuel supplier where the prices for fuel and ash removal are indexed to its PPA. This fuel contract expires in 2020 prior to the expiration of the PPA in 2030, resulting in fuel price risk for the remaining 10 years of the PPA. AES Warrior Run has begun efforts to source fuel longer term, and facilitate fuel flexibility.

Market Structure. Two of the primary fuels used by our U.S. generation facilities, coal and pet coke, are commodities with international prices set by market factors, although the price of the third primary fuel, natural gas is generally set domestically. Price variations for these fuels can change the composition of generation costs and energy prices in our generation businesses. Many of these generation businesses have entered into long-term PPAs with utilities or other offtakers. Some coal-fired power plant businesses in the U.S. with PPAs have mechanisms to recover fuel costs from the offtaker, including an energy payment that is partially based on the market price of coal. In addition, these businesses often have an opportunity to increase or decrease profitability from payments under their PPAs depending on such items as plant efficiency and availability, heat rate, ability to buy coal at lower costs through AES' global sourcing program, and fuel flexibility. Revenue may change materially as prices in fuel markets fluctuate, but the variable margin or profitability should not be materially changed when market price fluctuations in fuel are borne by the offtaker.

Regulatory Framework. Several of our generation businesses in the United States, currently operate as Qualifying Facilities ("QFs") as defined under Public Utility Regulatory Policies Act ("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). 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 ("EWG") as defined under EPAct 1992. These businesses, subject to approval of the Federal Energy Regulatory Commission ("FERC"), have the right to sell power at market-based rates, either directly to the wholesale market or to a third-party off taker such as a power marketer or utility/industrial customer. Under the Federal Power Act ("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.

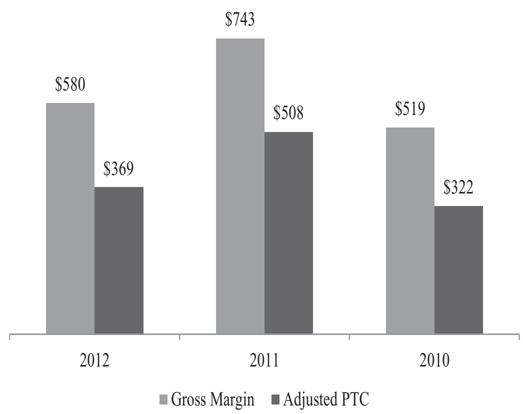
Other Regulatory Matters

The U.S. wholesale electricity market consists of multiple distinct regional markets that are subject to both federal regulation, as implemented by the U.S. FERC, and regional regulation as defined by rules designed and implemented by the 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. See Item 1A.—*Risk Factors* for additional discussion on U.S. regulatory matters.

Our businesses are subject to emission regulations, which may result in increased operating costs or the purchase of additional pollution control equipment if emission levels are exceeded. Our businesses periodically review their obligations for compliance with environmental laws, including site restoration and remediation. Because of 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, if any. For a discussion of environmental laws and regulations affecting the U.S. business, see *Other United States Environmental and Land Use Legislation and Regulations* later in this section. In April 2012, the EPA's rule to establish maximum achievable control technology standards for each hazardous air pollutant regulated under the Clean Air Act ("CAA") emitted from coal and oil-fired electric utilities, known as MATS became effective.

Andes SBU

Our Andes SBU has generation facilities in three countries, Chile, Colombia and Argentina. Our Andes operations accounted for 16%, 18% and 14% of consolidated AES gross margin and 18%, 28% and 21% of consolidated AES adjusted PTC (a non-GAAP measure) in 2012, 2011 and 2010, respectively. The percentages shown are the contribution by each SBU to gross adjusted PTC, i.e. the total adjusted PTC by SBU, before deductions for Corporate. AES Gener, which owns all of our assets in Chile, Chivor in Colombia and TermoAndes in Argentina, as detailed below, is a publicly-listed company in Chile. AES has a 71% ownership interest in AES Gener and this business is consolidated in our financial statements.



The following table provides highlights of our Andes operations:

Countries	Argentina, Chile and Colombia
Generation Capacity	7,740 gross MW (5,952 proportional MW)
Generation Facilities	33 (including 3 under construction)
Key Generation Businesses	AES Gener, Chivor and AES Argentina

Operating installed capacity of our Andes SBU totals 7,740 MW, of which 46%, 41% and 13% is located in Argentina, Chile and Colombia, respectively. Set forth in the table below is a list of our Andes SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
Chivor	Colombia	Hydro	1,000	71%	2000
Colombia Subtotal			*1,000*		
Gener[1]	Chile	Hydro/Coal/Diesel/ Biomass	986	71%	2000
Guacolda[2]	Chile	Coal/Pet Coke	608	35%	2000
Electrica Angamos	Chile	Coal	545	71%	2011
Electrica Santiago[3]	Chile	Gas/Diesel	479	71%	2000
Norgener	Chile	Coal/Pet Coke	277	71%	2000
Electrica Ventanas[4]	Chile	Coal	272	71%	2010
Chile Subtotal			*3,167*		
TermoAndes[5]	Argentina	Gas/Diesel	643	71%	2000
AES Gener Subtotal			4,810		
Alicura	Argentina	Hydro	1,050	100%	2000
Paraná-GT	Argentina	Gas/Oil/Biodiesel	845	100%	2001
San Nicolás	Argentina	Coal/Oil/Gas	675	100%	1993
Los Caracoles[6]	Argentina	Hydro	125	0%	2009
Cabra Corral	Argentina	Hydro	102	100%	1995
Quebrada de Ullum[6]	Argentina	Hydro	45	0%	2004
Ullum	Argentina	Hydro	45	100%	1996
Sarmiento	Argentina	Gas/Diesel	33	100%	1996
El Tunal	Argentina	Hydro	10	100%	1995
Argentina Subtotal			*2,930*		
Andes Total			7,740		

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

(2) Guacolda plants: Guacolda 1, Guacolda 2, Guacolda 3 and Guacolda 4. Unconsolidated entities for which the results of operations are reflected in Equity in Earnings of Affiliates.

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

(4) Electrica Ventanas plant: Nueva Ventanas.

(5) TermoAndes is located in Argentina, but is connected to both the SING in Chile and the SADI in Argentina.

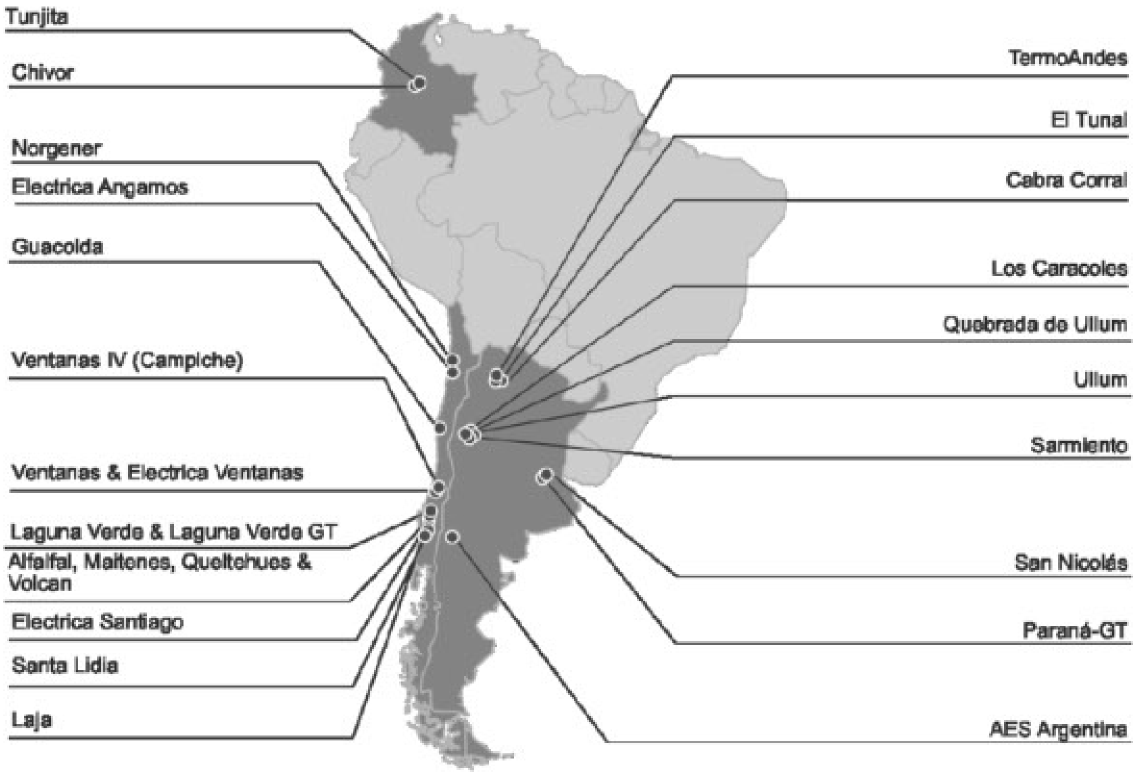
(6) AES operates these facilities through management or O&M agreements and owns no equity interest in these businesses.

Under construction

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Expected Year of Commercial Operations
Gener—Ventanas IV (Campiche)[1]	Chile	Coal	270	71%	2013
Gener—Guacolda V	Chile	Coal	152	36%	2015
Chile Subtotal			*422*		
Chivor—Tunjita	Colombia	Hydro	20	71%	2014
Colombia Subtotal			*20*		
Andes Total			442		

(1) Gener—Ventanas IV (Campiche): Currently in commissioning.

The following map illustrates the location of our Andes facilities:



Andes Businesses

Chile

Business Description. In Chile, through AES Gener, we are engaged in the generation and supply of electricity (energy and capacity) in the two principal markets: the Central Interconnected Electricity System ("SIC") and Northern Interconnected Electricity System ("SING"). As of December 31, 2012, AES Gener's net power production in the SIC totaled 11,590 GWh (24% of the SIC's total generation) and AES Gener's net power production in the SING totaled 4,989 GWh (33% of the SING's total generation). In terms of aggregate installed capacity, AES Gener is the second largest generation operator in Chile with an installed capacity of 3,810 MW and market share of 21% as of December 31, 2012. In the SIC, AES Gener has installed capacity of 2,345 MW representing 17% of gross installed capacity in the system. In the SING, AES Gener have installed capacity of 1,465 MW representing 32% of gross installed capacity in the system. AES Gener's installed capacity in the SING includes the TermoAndes plant, which is located in northwest Argentina and connected to both the SING by a transmission line owned by AES Gener, and the Argentine electricity grid. TermoAndes was originally constructed to supply the SING by exporting energy from 2000 to 2011. TermoAndes' electricity export permit expired on January 31, 2013. While AES Gener continues to evaluate potential renewal, TermoAndes is currently selling output of this plant in Argentina.

AES Gener owns a diversified generation portfolio in terms of geography, technology, customers and fuel source. AES Gener's installed capacity is located near the principal electricity consumption centers, including Santiago, Valparaiso and Antofagasta, extending from Antofagasta in the north to Concepción in south-central Chile. AES Gener's diverse generation portfolio, composed of hydroelectric, coal, gas, diesel and biomass facilities, allows the businesses to operate under a variety of market and hydrological conditions, manage AES Gener's contractual obligations with regulated and unregulated customers and, as required, provide back-up short-term market energy to the SIC and SING. AES Gener has experienced significant growth in recent years, responding to market opportunities with the completion of nine generation projects totaling approximately 1,400 MW and increasing AES Gener's installed capacity by 49% from 2006 to 2013. Additionally, they are in the process of commissioning a 270 MW coal-fired plant (Ventanas IV) and constructing an additional 152 MW coal-fired plant (Guacolda V). AES Gener plans to continue to grow with the construction of new projects in both the SIC and the SING, taking advantage of AES Gener's presence and knowledge of the market, in addition to AES Gener's project management and construction skills. AES Gener's key short-term development projects include the 532 MW coal-fired Cochrane power plant in the SING and the 531 MW run-of-river hydroelectric Alto Maipo power plant in the SIC.

In Chile, we align AES Gener's contracts with their efficient generation capacity, contracting a significant portion of their baseload capacity, currently coal and hydroelectric, under long-term contracts with a diversified customer base, which includes both regulated and unregulated customers. AES Gener reserves their higher variable cost units as designated back-up facilities, principally the diesel and gas-fired units in Chile, for sales to the short-term market during scarce system supply conditions, such as dry hydrological conditions and plant outages. In Chile, sales on the short-term market are made only to other generation companies that are members of the relevant Economic Load Dispatch Center ("CDEC") at the system marginal cost.

AES Gener currently has long-term contracts, with average terms between 10 and 18 years, with regulated distribution companies and unregulated customers such as mining and industrial companies. In general, these long-term contracts include both fixed and variable payments along with indexation mechanisms, which periodically adjust prices based on the generation cost structure related to the U.S. Consumer Price Index ("U.S. CPI"), the international price of coal, and in some cases, with pass-through of full fuel and regulatory costs, including changes in law.

In addition to energy payments, AES Gener also receives firm capacity payments for contributing to the system's ability to meet peak demand. These payments are added to the final electricity price paid by both unregulated and regulated customers. In each system, the CDEC annually determines the firm capacity amount allocated to each power plant. A plant's firm capacity is defined as the capacity that it can guarantee at peak hours during critical conditions, such as droughts, taking into account statistical information regarding maintenance periods and the water inflows in the case of hydroelectric plants. The capacity price is fixed by the National Energy Commission ("CNE") in the semi-annual node price report and indexed to the U.S. CPI and other relevant indices.

Market Structure. Chile has four power systems, largely as a result of its geographic shape and size. The SIC is the largest of these systems, with an installed capacity of 13,633 MW as of December 31, 2012. The SIC serves approximately 92% of the Chilean population, including the densely populated Santiago Metropolitan Region, and supplies 75% of the country's electricity demand. The SING serves about 6% of the Chilean population, supplying 24% of Chile's electricity consumption, and is mostly oriented toward mining companies.

In 2012, thermoelectric generation represented 69% of the total generation in Chile. In the SIC, thermoelectric generation represents 55% of installed capacity and is required to fulfill demand not satisfied by hydroelectric output, and is critical to guaranteeing reliable and dependable electricity supply under dry hydrological conditions. In the SING, which includes the Atacama Desert, the driest desert in the world, thermoelectric capacity represents 99.7% of installed capacity. The fuels used for generation, mainly coal, diesel and LNG, are commodities with international prices.

In the SIC, where hydroelectric plants represent a large part of the system's installed capacity, hydrological conditions largely influence plant dispatch and therefore, short-term market prices, given that river flow volumes, melting snow and initial water levels in reservoirs largely determine the dispatch of the system's hydroelectric and thermoelectric generation plants. Rainfall and snowfall occurs in Chile principally in the southern cone winter season (June to August) and during the remainder of the year precipitation is scarce. When rain is abundant, energy produced by hydroelectric plants can amount to more than 70% of total generation. In 2012, hydroelectric generation represented 41% of total energy production.

Regulatory Framework

Electricity Regulation. The governmental entity which has primary responsibility for the Chilean electricity system is the Ministry of Energy, acting directly or through the CNE and the Superintendency of Electricity and Fuels. The electricity sector is divided into three segments: generation, transmission and distribution. In general terms, generation and transmission expansion are subject to market competition, while transmission operation and distribution, are subject to price regulation. The transmission segment consists of companies that transmit the electricity produced by generation companies at high voltage. Companies which are owners of a trunk transmission system cannot participate in the generation or distribution segments.

Companies in the SIC and the SING that possess generation, transmission, sub-transmission or additional transmission facilities, as well as unregulated customers directly connected to transmission facilities, are coordinated through the CDEC, which minimizes the operating costs of the electricity system, while meeting all service quality and reliability requirements. The principal purpose of the CDEC is to ensure that the most efficient electricity generation available to meet demand is dispatched to customers. The CDEC dispatches plants in merit order based on their variable cost of production which allows for electricity to be supplied at the lowest available cost.

All generators can commercialize energy through contracts with distribution companies for their regulated and unregulated customers, or directly with unregulated customers. Unregulated customers are customers whose connected capacity is higher than 2 MW. Under law, both regulated and unregulated customers are required to purchase 100% of their electricity requirements under contract. Generators may also sell energy to other power generation companies on a short-term basis. Power generation companies may also engage in contracted sales among themselves at negotiated prices, outside the short-term market. Electricity prices in Chile, under contract and on the short-term market, are denominated in U.S. Dollars although payments are made in Chilean pesos.

Other Regulatory Considerations. In 2011, a 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 (sulfur dioxide), NOx (nitrogen dioxide) and mercury emission will begin to apply in mid-2016, except for those plants operating in zones declared saturated or latent zones (areas at risk of or affected by excessive air pollution), where these emission limits will become effective by June 2015. In order to comply with the new emission standards, AES Gener in Chile will invest approximately $280 million, at its older coal facilities, including its proportional investment in an equity-method investee, Guacolda. In 2012, AES Gener initiated these investments, spending approximately $42 million, and the remaining $238 million will be invested between 2013 and 2015 in order to comply within the required timeframe.

Chilean law requires every electricity generator to supply a certain portion of their total contractual obligations with non-conventional renewable energies (“NCREs”). The required amount is determined based on contract agreements executed after August 31, 2007. The NCRE requirement is equal to 5.0% for the period from 2010 through 2014 and thereafter the required percentage increases by 0.5% each year, to a maximum of 10.0% by 2024. 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 NCRE from qualified generators or by paying the applicable fines for non-compliance. AES Gener currently fulfills the NCRE requirements by utilizing AES Gener’s own biomass power plants and by purchasing NCREs from other generation companies. They have sold certain water rights to companies that are developing small hydro projects, entering into power purchase agreements with these companies in order to promote development of these projects, while at the same time meeting the NCRE requirements. At present, AES Gener is in the process of negotiating additional NCRE supply contracts to meet the future NCRE requirements. The authorities have announced a potential increase in future NCRE requirements and a proposed bill is being discussed in Congress.

Key Financial Drivers

In Chile, AES Gener's contracting strategy, determining both the amount of capacity to contract or leave uncommitted for spot market sales and the relevant pricing formulas including indexation, is important to our profitability. AES Gener aligns their contracts with their efficient generation capacity, contracting a significant portion of their efficient capacity under long-term contracts, while reserving their higher variable cost units for sales on the spot market. The performance of their generating assets, efficiency and availability, is also a critical part of their strategy in order to maximize contracted margins and avoid exposure to spot price volatility.

In the SIC, hydrological conditions are also important financial drivers since they largely influence plant dispatch and therefore, spot market prices. AES Gener becomes a short-term purchaser of electricity from other generation companies during rainy hydrological conditions, when short-term market prices are at their lowest, and AES Gener's spot sales of electricity generated by their back-up facilities increase in periods of low water conditions, when short-term market prices are at their highest. Both extreme hydrological conditions provide AES Gener with improved earnings and cash flow.

Successful execution and commencement of operation of AES Gener's growth projects under construction, currently Ventanas IV (Campiche) and Guacolda V is important to their financial performance. In accordance with AES Gener's commercial contract strategy, in order to reduce their exposure to the potential imbalance between supply and demand and ensure investment recovery, their policy is to contract a significant proportion of the new efficient project capacity under long-term energy supply contracts.

Colombia

Business Description. As of December 31, 2012, AES Gener's net power production in Colombia was 4,664 GWh (8% of the country's total generation). The Chivor plant, a subsidiary of AES Gener, is a hydroelectric facility with installed capacity of 1,000 MW, located approximately 160 km east of Bogota. The installed capacity represents approximately 7% of system capacity as of December 31, 2012. The plant consists of eight 125 MW dam-based hydroelectric generating units in two separate sub-facilities. Because all of Chivor's installed capacity in Colombia is hydroelectric, they are dependent on the prevailing hydrological conditions in the region in which they operate. Hydrological conditions largely influence generation and the short-term prices at which they sell Chivor's non-contracted generation in Colombia.

Chivor's commercial strategy focuses on selling between 75% and 85% of the annual expected output under contracts, principally with distribution companies, in order to provide cash flow stability. These bilateral contracts with distribution companies are awarded in public bids and normally last from one to three years. The remaining generation is sold on the short-term market to other generation and trading companies at the system marginal cost, allowing us to maximize the operating margin during optimal price conditions.

Additionally, Chivor receives reliability payments for the availability and reliability of Chivor's reservoir during periods of scarcity, such as adverse hydrological conditions. These payments, referred to as "reliability charge payments" are designed to compensate generation companies for the firm energy that they are capable of providing to the system during critical periods of low supply in order to prevent electricity shortages.

Market Structure

Electricity supply in Colombia is concentrated in one main system, the National Interconnected System ("SIN"). The SIN encompasses one-third of Colombia's territory, providing coverage to 96% of the country's population. The SIN's installed capacity totaled 14,533 MW as of December 31, 2012, composed of 67% hydroelectric generation, 31% thermoelectric generation and 2% other. The dominance of hydroelectric generation and the marked seasonal variations in Colombia's hydrology result in price volatility in the short-term market. In 2012, 80% of total energy demand was supplied by hydroelectric plants with the remaining supply from thermoelectric generation (19%) and cogeneration and self-generation power (1%). From 2002 to 2012, electricity demand in the SIN has grown at a compound annual growth rate of 2.9% and the Mining and Energetic Planning Unit ("UPME") projects an average annual compounded growth rate in electricity demand of 4% per year for the next ten years.

Regulatory Framework

Electricity Regulation. Since 1994, the electricity sector in Colombia has operated as a competitive market framework for the generation and sale of electricity and a regulated framework for transmission and distribution. The distinct activities of the electricity sector are governed by various laws and the regulations and technical standards issued by the Energy and Gas Regulation Commission ("CREG"). Other government entities which play an important role in the electricity industry include: the Ministry of Mines and Energy, which defines the government's policy for the energy sector; the Public Utility Superintendency of Colombia, which is in charge of overseeing and inspecting the utility companies; and the UPME, which is in charge of planning the expansion of the generation and transmission network.

The generation sector is organized on a competitive basis with companies selling their generation in the wholesale market at the short-term price or under bilateral contracts with other participants, including distribution companies, generators and traders, and unregulated customers at freely negotiated prices. Generation companies must submit price bids and report the quantity of energy available on a daily basis. The National Dispatch Center dispatches generators in merit order based on bid offers in order to ensure that demand will be satisfied by the lowest cost combination of available generating units.

Other Regulatory Considerations. In the past few years, Colombian authorities have discussed proposals to make certain regulatory changes. One proposal is to replace or complement the current public auction system in which each distribution company holds an auction for its specific requirements and subsequently executes bilateral contracts with generation or trading companies, with a centralized auction in which the market administrator purchases energy for all distribution companies. Additionally, a proposal has been discussed which would allow authorities to dictate emergency energy situations, in cases such as severe drought conditions, in order to implement measures to prevent shortages and other negative economic impacts.

Key Financial Drivers

Hydrological conditions largely influence Chivor's generation level. Maintaining the appropriate contract level, while working to maximize revenue, through sale of excess generation, is key to Chivor's results of operations.

Argentina

Our Business. As of December 31, 2012, AES Argentina's net power production in the Argentine Interconnected System ("SADI") totaled 14,426 GWh, representing 11% of the SADI's total generation. AES Argentina operates 3,573 MW which represents 11% of country's total installed capacity, making us the third-largest generator. The installed capacity in the SADI includes the TermoAndes plant, a subsidiary of AES Gener, which is connected both to the SADI and the Chilean SING. AES Argentina has a diversified generation portfolio of ten generation facilities, comprised of 62% thermoelectric and 38% hydroelectric capacity. All of the thermoelectric capacity has the capability to burn alternative fuels. Approximately 69% of the thermoelectric capacity can operate alternatively with natural gas or diesel oil and the remaining 31% can operate alternatively with natural gas or fuel oil.

AES Argentina sells its production to customers on the short-term market, where prices are largely regulated. In 2012, approximately 80% of the energy was sold on the short-term market and 20% was under contract. Short-term prices are determined in Argentine pesos by the Wholesale Electric Market Administrator ("CAMMESA") and have been frozen at approximately $120 pesos per MWh for the past three years.

All of the thermoelectric facilities have the ability to use natural gas and receive gas supplied through contracts with Argentine producers. In recent years, gas supply restrictions in Argentina, particularly during the southern cone's winter season, have affected some of the plants, specifically the TermoAndes plant which is connected to the SING by a transmission line owned by AES Gener. The TermoAndes plant commenced operations in 2000, selling exclusively into the Chilean SING. In 2008, following requirements of the Argentine authorities, TermoAndes connected its two gas turbines to the SADI, while maintaining its steam turbine connected to the SING. However, since mid-December 2011, TermoAndes has been selling the plant's full capacity in the SADI. TermoAndes' electricity permit to export to the SING expired on January 31, 2013 and potential renewal is being evaluated.

Market Structure. The SADI electricity market is managed by CAMMESA. As of December 31, 2012, the installed capacity of the SADI totaled 31,139 MW. In 2012, 66% of total energy demand was supplied by thermoelectric plants, 29% by hydroelectric plants and 5% from nuclear, wind and solar plants.

Thermoelectric generation in the SADI is principally fueled by natural gas. However, since 2004, and due to natural gas shortages, in addition to increasing electricity demand, the use of alternative fuels in thermoelectric generation, such as oil and coal has increased. Given that the cost of these fuels is generally higher than natural gas, the extra cost or "dispatch surcharge", is currently reimbursed by CAMMESA, by including the surcharge in the energy margin paid to generators in order to compensate them for the cost of fuel. CAMMESA publishes reference prices on a biweekly basis for each type of fuel, capping the maximum price to be paid by generators.

Given the importance of hydroelectric facilities in the SADI, hydrological conditions determining river flow volumes and initial water levels in reservoirs largely influence hydroelectric and thermoelectric plant dispatch. Rainfall occurs principally in the southern cone winter season (June to August).

Regulatory Framework

Electricity Regulation. The Argentine regulatory framework divides the electricity sector into generation, transmission and distribution. The wholesale electric market is made up of generation companies, transmission companies, distribution companies and large customers who are allowed to buy and sell electricity. Generation companies can sell their output in the short-term market or to customers in the contract market. The wholesale electric market is administrated by CAMMESA, which is responsible for dispatch coordination and determination of short-term prices. The Electricity National Regulatory Agency is in charge of regulating public service activities and the Ministry of Federal Planning, Public Investment and Services, through the Energy Secretariat, regulates system dispatch and grants concessions or authorizations for sector activities.

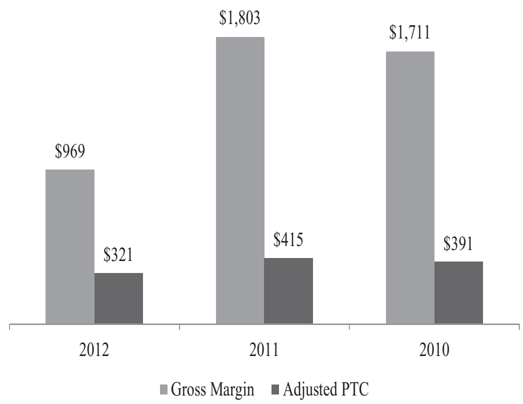
Since 2001, significant modifications have also been made to the electricity regulatory framework. These modifications include tariff conversion to Argentinean Pesos, freezing of tariffs, the cancelation of inflation adjustment mechanisms and the introduction of a complex pricing system in the wholesale electric market, which have materially affected electricity generators, transporters and distributors, and generated substantial price differences within the market. Since 2004, as a result of energy market reforms and overdue accounts receivables owed by the government to generators operating in Argentina, AES Argentina contributed certain accounts receivables to fund the construction of new power plants under FONINVEMEM agreements. These receivables accrue interest and are collected in monthly installments over 10 years once the related plants begin operations. At this point three funds have been created to construct three facilities. The first two plants are operating and payments are being received, while the third plant is under development. AES Argentina will receive a pro rata ownership interest in these newly-built plants once the accounts receivables have been paid. The Argentine government has continued to intervene in the energy sector and AES Argentina believes that additional modifications to Argentine electricity sector regulations are likely. In August 2012, authorities advised of a proposal to modify the current energy regulatory framework, moving from a "marginal cost market" to a "cost-plus market", although AES Argentina is not aware of the details or timing for this modification at present. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations* for additional details.

Key Financial Drivers

Potential changes in regulations, especially changes related to a “revenue requirement” pricing scheme or a change to the coal rule, which establishes the margin for AES Argentina’s San Nicolas plant, are key drivers for the Argentina business. The ability to contract sales with unregulated customers at TermoAndes and obtain the natural gas required to supply the contracts is another area of focus for the business. Macroeconomic conditions, further regulatory changes, and AES Argentina’s ability to collect on receivables, including FONINVEMEM and future receivables, impact operating performance and cash flow. Finally, hydrological conditions largely determine our plants’ dispatch.

Brazil SBU

Our Brazil SBU has generation and distribution facilities. Our Brazil operations accounted for 26%, 45% and 45% of consolidated AES gross margin and 15%, 23% and 25% of consolidated AES adjusted PTC (a non-GAAP measure) in 2012, 2011 and 2010, respectively. The percentages shown are the contribution by each SBU to gross adjusted PTC, i.e. the total adjusted PTC by SBU, before deductions for Corporate.



The following table provides highlights of our Brazil operations:

Generation Capacity	3,298 gross MW (932 proportional MW)
Utilities Penetration	7.7 million customers (54,408 GWh)
Generation Facilities	13
Utilities Businesses	2
Key Generation Businesses	Tietê and Uruguaiana
Key Utility Businesses	Eletropaulo and Sul

Generation. Operating installed capacity of our Brazil SBU totals 2,658 MW in AES Tietê plants, located in the State of São Paulo. Tietê represents approximately 11%, as of December 2012, of the total generation capacity in the State of São Paulo and is the second largest private generator in Brazil. We also have another generation plant, AES Uruguaiana, located in the South of Brazil with a installed capacity of 640 MW.

Set forth in the table below is a list of our Brazil SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
Tietê[(1)]	Brazil	Hydro	2,658	24%	1999
Uruguaiana	Brazil	Gas	640	46%	2000
Brazil Total			3,298		

(1) Tietê plants with installed capacity: Água Vermelha (1,396 MW), Bariri (143 MW), Barra Bonita (141 MW), Caconde (80 MW), Euclides da Cunha (109 MW), Ibitinga (132 MW), Limoeiro (32 MW), Mogi-Guaçu (7 MW), Nova Avanhandava (347 MW), Promissão (264 MW), Sao Joaquim (3 MW) and Sao Jose (4 MW).

Distribution. AES owns interests in two distribution facilities in Brazil. Eletropaulo operates in the metropolitan area of São Paulo and adjacent regions, distributing electricity to 24 municipalities in a total area of 4,526 km^2, covering a region of high demographic density and the largest concentration of GDP in the country. It is the largest power distributor in Latin America serving approximately 16.6 million people and 6.5 million consumer units.

AES Sul is responsible for supplying electricity to 118 municipalities of the metropolitan region of Porto Alegre to the border with Uruguay and Argentina in a total area of 99,512 km^2, serving approximately 3.3 million people and 1.24 million consumer units.

Set forth in the table below is a list of our Brazil SBU distribution facilities:

Business	Location	Approximate Number of Customers Served as of 12/31/2012	GWh Sold in 2012	AES Equity Interest (Percent, Rounded)	Year Acquired
Eletropaulo	Brazil	6,483,000	45,557	16%	1998
Sul	Brazil	1,240,000	8,851	100%	1997
		7,723,000	54,408		

The following map illustrates the location of our Brazil facilities:

Brazil Businesses

Business Description

Generation. Tietê is a portfolio of 12 hydroelectric power plants, with total installed capacity of 2,658 MW in the state of São Paulo. Tietê was privatized in 1999 under a 30-year concession expiring in 2029. AES owns a 24% economic interest, our partner the Brazilian Development Bank ("BNDES") owns 28% and the remaining shares are publicly held or held by government-related entities. AES is the controlling shareholder and manages and consolidates this business.

Tietê sells 100% of its assured capacity to Eletropaulo under a long-term PPA, which is expiring in December 2015. After that, Tiete's strategy is to contract 95% of this energy and the remaining portion is to be sold in the short-term market. The contract is price-adjusted annually for inflation (IGP-M). Current regulated auctions for similar energy are clearing at prices that are below our existing contract prices.

Under the concession agreement, Tietê had an obligation to increase its capacity by 15% by 2007, with no penalty imposed for lack of compliance, although there is a legal case initiated by the state of Sao Paulo requiring the investment to be performed. Tietê, as well as other concessionaire generators, was not able to meet this requirement due to regulatory, environmental, hydrological and fuel constraints. Tietê is in the process of analyzing options to meet the obligation.

Uruguaiana is a 640 MW gas-fired combined cycle power plant commissioned in December 2000. AES manages and owns a 46% economic interest and the remaining is held by BNDES. The facility is located in the town of Uruguaiana in the state of Rio Grande do Sul. The plant's operations were suspended in April 2009 due to unavailability of gas. However the facility resumed operations on February 8, 2013 and expects to continue for 60 days due to a recently secured short-term supply of LNG for the facility. At the first stage, the thermal plant will operate with capacity of approximately 164 MW. Uruguaiana is working to secure gas on a long-term basis, to operate at the plant's full capacity.

Distribution . Eletropaulo distributes electricity to 24 municipalities that compose the Greater São Paulo, including the capital of São Paulo State, Brazil's main economic and financial center. The Company is the largest electric power distributor in Latin America in terms of both revenues and volume of energy distribution.

AES owns 16% of the economic interest of Eletropaulo, our partner, BNDES, owns 19% and the remaining shares are publicly held or held by government-related entities. AES is the controlling shareholder and manages and consolidates this business. Eletropaulo holds a 30-year concession that expires in 2028.

Sul distributes electricity in 118 municipalities in the metropolitan region of Porto Alegre up to the frontier with Uruguay and Argentina, respectively, in the municipalities of Santana do Livramento and Uruguaiana/São Borja at the extreme west of the state of Rio Grande do Sul. AES owns 100% of the economic interest and manages this business under a 30-year concession expiring in 2027.

Market Structure

Tietê is one of many generators in the 117,000 MW installed capacity system comprising approximately 75% of the market with regulated customers and the remainder with free customers. Of this total system installed capacity, 78% is hydroelectric, 16% is thermoelectric and 6% is from renewable sources (biomass and wind).

Regulatory Framework

The Brazilian power sector has a number of different regulatory bodies, the most relevant of which are: (i) the Minister of Mines and Energy ("MME"), which is the government's main energy policy maker; (ii) the Energy Planning Enterprise ("EPE"), which is the government's agency for the long-term planning of the country's generation and transmission systems expansion to ensure high reliability of supply at the lowest possible cost; (iii) ANEEL, which is the agency that runs the day-to-day execution of the government's policies, including tariff adjustments and periodic tariff resets for distribution; and (iv) the National System Operator ("ONS"), which is responsible for coordinating and controlling the operation of the national grid.

The Government of Brazil recently announced an Energy Cost Reduction Program, which targets a 20 percent reduction in electricity prices. About one-third of this planned reduction is expected to be driven by lowering sector charges (indirect taxes). The remaining two-thirds of this reduction is being targeted through re-negotiations of new conditions with various generators and transmission and distribution companies, whose concession contracts are up for renewal between 2015 and 2017. The Government of Brazil issued Provision Measure 579 (MP 579) and other related rules. MP 579 is still pending Congressional approval and implementation of the Energy Cost Reduction Program is scheduled to be completed in the first quarter. The concession at Tietê, our generation business in Brazil, was granted after 1995 and expires in 2029 and thus is not subject to this regulation. Furthermore, we are insulated in the short-term, as 100% of Tietê's output is contracted with Eletropaulo through December 2015. Beyond 2015, any developments will be a function of the supply-demand and new investment dynamics in Brazil. Both Eletropaulo and Sul, have concessions granted after 1995 and valid until 2028 and 2027, respectively, and thus are not affected by the proposed MP 579. On January 24, 2013, an extraordinary tariff reduction for all distribution companies was announced with an average reduction at Eletropaulo of 20% and at Sul of 25%. Since the distribution businesses earn a return on the regulated asset base and energy purchases are treated as a pass-through cost, management expects these changes will have a neutral impact on our gross margin.

Electricity Regulation. In Brazil, MME determines the maximum amount of energy that a plant can sell "assured energy", which represents the long-term average expected energy production of the plant. Under the current rules, the plant's assured energy can be sold to the distribution companies through long-term (regulated) auctions or under unregulated bilateral contracts with large consumers or energy trading companies.

Under the power sector model, a distribution company is obligated to contract 100% of the anticipated energy needs through the regulated auction market. The regulated utilities can pass through the amounts contracted up to 103% of their load. If the company is contracted below 99% of its projected load, there is no pass-through mechanism for the energy purchased below that limit.

ANEEL sets the tariff for each distribution company, which is based on Return on Asset Base methodology that also benchmarks operational costs against other distribution companies.

The tariff charged to regulated customers consists of two elements: (i) full pass through of non-manageable costs ("Parcel A"), which includes energy purchase costs, sector charges and transmission and distribution system expenses; and (ii) 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 regulatory pre-tax weighted average cost of capital).

For distribution companies, a tariff reset occurs every four to five years, depending on the specific business. Eletropaulo's tariff reset occurs every four year and the next tariff reset will be in July 2015. Sul's tariff resets every five years and the current rate will be set for another five years in April 2013.

In addition to tariff reset, Parcel A is reviewed and adjusted once a year. Parcel B is adjusted once every year reflecting inflation offset by X-Factor to capture windfall gains from volume sales growth.

Distribution companies could also be entitled to extraordinary tariff revisions, subject to ANEEL approval, in the event of significant and proven loss of the economic and financial equilibrium.

Eletropaulo has ongoing discussions with the regulator in the administrative level regarding the parameters of the tariff reset applied in July 2012, retroactive to July 2011. The main discussions involve the shielded regulatory asset base and whether adjustments should be made to it, the amount of investments made by the company that were not included in the tariff and the benchmark used for regulatory losses .

During 2012, Eletropaulo received two infraction notices from ANEEL, relating to the financial audit of its fixed assets. The notices allege non-conformities in the regulatory accounting applied by Eletropaulo to the fixed assets and non-conformities in the regulatory asset base, both of which impact the regulatory asset base used to calculate the tariff charged to customers. Management has filed appeals contesting the alleged non-conformities and fines imposed, and are awaiting responses. Management has recognized its best estimate of the probable loss as of December 31, 2012. There can be no assurances that additional losses may be necessary which could have a material impact on our results of operations.

For Sul, the tariff reset for the next five years, will occur in April 2013. ANEEL opened a public hearing on February 5, 2013, which is expected to run until March 8, 2013 to discuss the rates. Although we believe Sul should receive a fair and reasonable tariff, there can be no assurances made around the outcome of the process. In the event that the tariff reset is below our expectations, there could be a material impact on our results of operations.

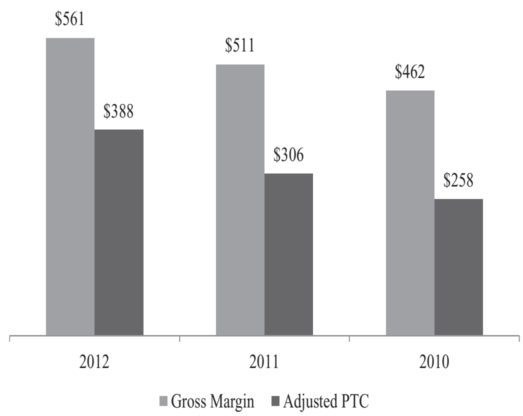
Key Financial Drivers

As the system is highly dependent on hydroelectric generation, Brazil SBU generation companies are affected by the hydrology in the overall sector, as well as availability of Tiete's plants and reliability of the Uruguaiana facility. The availability of gas for continued operations is a driver for Uruguaiana.

For Brazil SBU distribution companies, the demand for electricity is affected by economic activity, weather patterns and customers' consumption behavior. Further, AES Sul is focused on working with stakeholders to determine a fair and reasonable outcome for the tariff reset scheduled to be implemented in April 2013. Finally, the distribution companies' operating performance is driven by the quality of service and ability to control non-technical losses.

MCAC SBU

Our MCAC SBU has a portfolio of distribution businesses and generation facilities, including renewable energy, in six countries, with a total capacity of 3,860 MW and distribution networks serving more than 1.2 million customers as of December 31, 2012. MCAC operations accounted for 15%, 13% and 12% of consolidated AES gross margin and 18%, 17% and 17% of consolidated AES adjusted PTC (a non-GAAP measure) in 2012, 2011 and 2010, respectively. The percentages shown are the contribution by each SBU to gross adjusted PTC, i.e. the total adjusted PTC by SBU, before deductions for Corporate.



The following table provides highlights of our MCAC SBU operations:

Countries	Dominican Republic, El Salvador, Mexico, Panama , Puerto Rico and Trinidad
Generation Capacity	3,860 gross MW (2,585 proportional MW)
Utilities Penetration	1.2 million customers (3,642 GWh)
Generation Facilities	16
Utilities Businesses	4
Key Generation Businesses	Andres, Panama and TEG TEP
Key Distribution Businesses	El Salvador

The total operating installed capacity of our MCAC SBU is distributed 27%, 22%, 18% and 14% in Mexico, Dominican Republic, Panama and Puerto Rico, respectively. The table below lists our MCAC SBU facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
Andres	Dominican Republic	Gas	319	100%	2003
Itabo[1]	Dominican Republic	Coal/Gas	295	50%	2000
DPP (Los Mina)	Dominican Republic	Gas	236	100%	1996
Dominican Republic Subtotal			*850*		
AES Nejapa	El Salvador	Landfill Gas	6	100%	2011
El Salvador Subtotal			*6*		
Merida III	Mexico	Gas	505	55%	2000
Termoelectrica del Golfo (TEG)	Mexico	Pet Coke	275	99%	2007
Termoelectrica del Penoles (TEP)	Mexico	Pet Coke	275	99%	2007
Mexico Subtotal			*1,055*		
Bayano	Panama	Hydro	260	49%	1999
Changuinola	Panama	Hydro	223	100%	2011
Chiriqui—Esti	Panama	Hydro	120	49%	2003
Chiriqui—Los Valles	Panama	Hydro	54	49%	1999
Chiriqui—La Estrella	Panama	Hydro	48	49%	1999
Panama Subtotal			*705*		
Puerto Rico	US—PR	Coal	524	100%	2002
Puerto Rico Subtotal			*524*		
Trinidad	Trinidad	Gas	720	10%	2011-2012
Trinidad Subtotal			*720*		
MCAC Total			3,860		

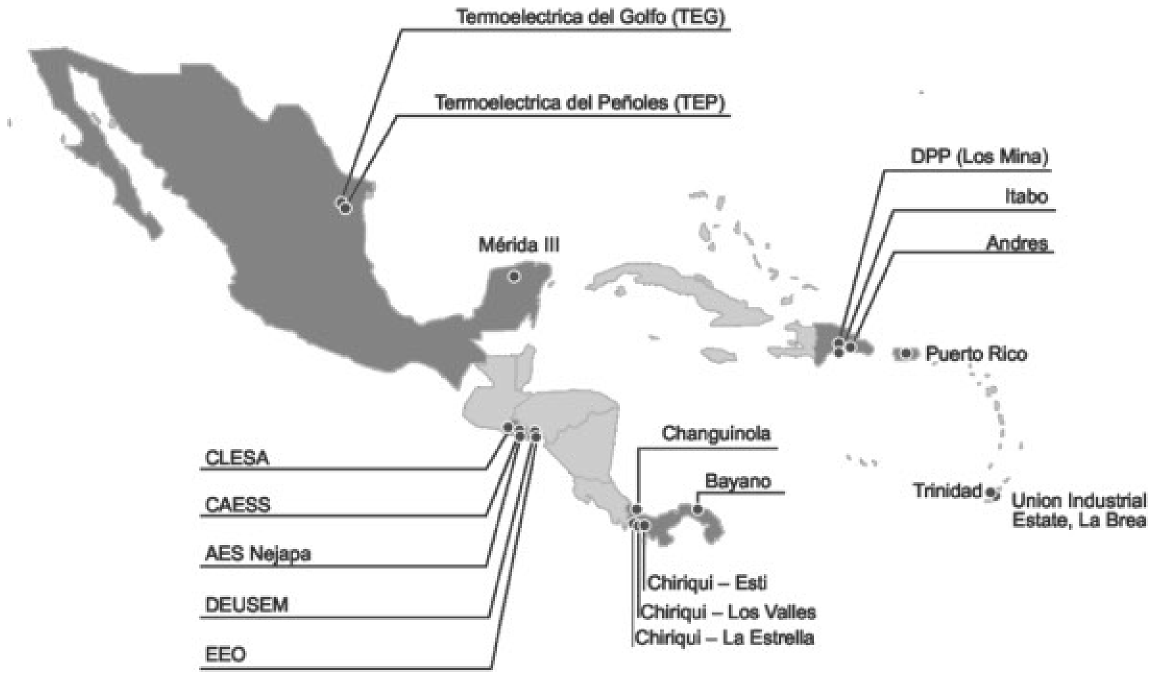
(1) Itabo plants: Itabo complex (two coal-fired steam turbines and one gas-fired steam turbine).

MCAC Utilities. The Company's MCAC utilities in El Salvador 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.

Our distribution businesses are located in El Salvador and distribute power to more than 1.2 million people in the country. This business consists of 4 companies, each of which operates in defined service areas as described in the table below:

Business	Location	Approximate Number of Customers Served as of 12/31/2012	GWh Sold in 2012	AES Equity Interest (Percent, Rounded)	Year Acquired
CAESS	El Salvador	558,000	2,160	75%	2000
CLESA	El Salvador	342,000	852	64%	1998
DEUSEM	El Salvador	68,000	119	74%	2000
EEO	El Salvador	260,000	511	89%	2000
		1,228,000	3,642		

The following map illustrates the location of our MCAC facilities:



MCAC Businesses

Mexico

Business Description. We have an installed capacity of 1,055 MW, which consists of 550 MW from self-supply generation, a regulation that allows qualifying industrial entities to generate their own electricity for a lower cost and security of supply, and 505 MW as an Independent Power Producer ("IPP"). All three units are baseload and run all year.

The 550 MW self-supply facility comprised of Termoeléctrica del Golfo ("TEG") and Termoeléctrica Peñoles ("TEP"), located in San Luis Potosi, Mexico. The plants supply power to their offtakers under long-term PPAs that have a 90% availability guarantee. TEG and TEP secure their fuel (pet coke) under a long-term contract.

AES Merida III ("Merida") is a 505 MW IPP generation facility. The facility is a combined-cycle gas turbine ("CCGT") with the ability to use dual fuel technology located in Merida, on Mexico's Yucatan peninsula. Merida consists of two combustion turbines that can burn natural gas or diesel fuel and two heat recovery steam generators and a single steam turbine. Under the Electric Public Service Law, Merida sells power exclusively to the Federal Commission of Electricity ("CFE") as an IPP under a long-term PPA with a contractual net 484 MW. Additionally, the plant purchases natural gas and diesel fuel under a long-term contract, the cost of which is then passed through to CFE under the terms of the PPA.

Market Structure

Mexico has a single national electricity grid, the National Power System ("SEN"), covering nearly all of Mexico's territory. Mexico has an installed capacity totaling 53 GW with a generation mix of 62% thermal, 22% hydroelectric and 16% other. Electricity consumption is split between the following end users: industrial (59%), residential (26%) and commercial and service (15%).

Regulatory Framework

The CFE, which is mandated by the Mexican Constitution, is the state-owned electric monopoly which operates the national grid and generates electricity for the public. CFE regulates wholesale tariffs, which are largely set by the marginal production cost of oil and gas-fired generation. The Mexican energy system is fully integrated under the sole responsibility of CFE. The Electrical Public Service Law allows privately owned projects to produce electricity for self-supply application and/or IPP structures.

Private parties are allowed to invest in certain activities in Mexico's electrical power market, and 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. Permit holders are required to enter into PPAs with the CFE to sell all surplus power produced. 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.

Key Financial Drivers

Plant availability is the largest single performance driver of this business. Additionally, AES' Mexican businesses benefit from the wholesale price margin versus pet coke costs for any sales greater than the guaranteed output.

Panama

Business Description. AES represents 29% of the installed capacity and almost 30% of the firm capacity in Panama. We own and operate a total of five hydroelectric plants, totaling 705 MW of installed capacity. The portfolio is a mix of run-of-river facilities and reservoir facilities. Changuinola is a wholly owned subsidiary. The other four plants are owned jointly by AES (49%), the Republic of Panama (50.4%) and minority shareholders (0.6%).

In the short—to medium-term, AES Panama has approximately 90% of its firm capacity contracted with distribution companies, while large customers account for sales volumes representing 7% of the portfolio. The balance of AES Panama's contracts are with the three distribution companies. Currently, there are no over-the-counter or forward products available to AES Panama for hedging electricity.

Market Structure. Panama's current total installed capacity is 2,427 MW, of which 58% is hydroelectric and 42% is thermal. Thermal generation facilities in the country run on diesel, bunker fuel, and coal. Panama's total firm capacity is currently 1,632 MW. For hydroelectric plants, firm capacity is based upon the amount of energy that a unit can generate in the eight peak hours of the day, calculated on the basis of hydrological flows.

The Panamanian electrical sector is composed of three distinct operating business units: generation, distribution and transmission, all of which are governed by the Electric Law 6 enacted in 1997. 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 of PPAs are determined through a competitive bidding process and are governed by the Commercial Rules. Outside of the PPA market, generators may buy and sell energy in the short-term market. Energy sold in the short-term market corresponds to the hourly difference between the actual dispatch of energy by each generator and its contractual commitments to supply energy. The National Dispatch Center ("CND") merit order dispatch and water value and sets the energy short-term price on an hourly basis according to this merit order.

Regulatory Framework. The National Secretary of Energy ("SNE") has the responsibilities of planning, supervising and controlling policies of the energy sector within Panama. With these responsibilities, the SNE proposes laws and regulations to the executive agencies that promote the procurement of electrical energy, hydrocarbons and alternative energy for the country.

The regulator of public services, known as the National Authority of Public Services ("ASEP") is an autonomous agency of the government. ASEP is responsible for the control and oversight of public services including electricity and the transmission and distribution of natural gas utilities and the companies that provide such services.

Generators can only contract their firm capacity. Physical generation of energy is determined by the CND regardless of contractual arrangements.

Key Financial Drivers

The seasonal effect of the hydrologic inflows affects generation and therefore gross margin. During the low inflow period (January to May) generation tends to be lower and AES Panama may purchase energy in the short-term market to cover contractual obligations. The rest of the year (June to December) their generation tends to be higher and they may sell energy in excess of their contracts to the short-term market. Hydrology and commodity prices are a risk to the Panama business. Hydrology affects the amount of generation and commodity prices affect the opportunity cost of the hydroelectric generation facilities with a reservoir. Both variables affect the short-term price, and during periods of low hydrology and high fuel price, the business can be negatively affected.

Dominican Republic

Business Description. AES Dominicana consists of its operating subsidiaries Andres, Dominican Power Partners ("DPP") and Itabo. Andres and DPP are both wholly-owned subsidiaries of AES, while Itabo is 50%-owned by AES, 49.97% owned by FONPER, a government-owned utility and the remaining 0.03% is owned by employees. AES has 28% of the system capacity (850 MW) and supplies approximately 40% of energy demand through its three generation facilities.

Andres has a combined cycle gas turbine and generation capacity of 319 MW and the only LNG import facility in the country. DPP (Los Mina) has two open cycle natural gas turbines and generation capacity of 236 MW. Both companies have in aggregate 555 MW of installed capacity of which 450 MW is contracted until 2017 with the government-owned distribution companies and non-regulated users. Itabo owns and operates two thermal power generation units with 295 MW of installed capacity in total. Itabo's PPAs are with the government-owned distribution companies and expire in 2016.

AES Dominicana has a long-term LNG purchase contract, which expires in 2023, with the price linked to NYMEX Henry Hub, which translates into a competitive advantage as we are currently purchasing LNG at prices lower than those on the international market. In 2005, Andres entered into a contract to sell re-gasified LNG for further distribution to industrial users within the Dominican Republic, using compression technology to transport it within the country. In January 2010, the first LNG truck tanker loading terminal started operations. With this investment, AES is capturing demand from industrial and commercial customers.

Market Structure

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 (15%).

Natural Gas Market. The natural gas market in the Dominican Republic was developed in 2001 when AES entered into a long-term contract for LNG and constructed AES Dominicana's LNG regasification terminal.

Regulatory Framework

The regulatory framework in the Dominican Republic consists of a decentralized industry including generation, transmission and distribution, with regulated prices in transmission and distribution, and a competitive wholesale generation market. All electric companies (generators, transmission and distributors), are subject to and regulated by the General Electricity Law ("GEL").

Two main agencies are responsible for monitoring and ensuring compliance with the GEL. The National Energy Commission ("CNE") is in charge of drafting and coordinating the legal framework and regulatory legislation; proposing and adopting policies and procedures to assure best practices; drafting plans to ensure the proper functioning and development of the energy sector; and promoting investment. The Superintendence of Electricity's ("SIE") main responsibilities include monitoring and supervising compliance with legal provisions and rules and monitoring compliance with the technical procedures governing generation, transmission, distribution and commercialization of electricity, and supervising electric market behavior in order to avoid monopolistic practices.

The electricity tariff applicable to regulated customers is subject to regulation within the concessions of the distribution companies. Clients with demand above 1.2 MW are classified as unregulated customers and their tariffs are unregulated.

Fuels and hydrocarbons are regulated by a specific law, which establishes prices to end customers and a tax on consumption of fossil fuels. For natural gas there are regulations related to the procedures to be followed to grant licenses and concession: i) distribution, including transportation and loading and compression plant; ii) the installation and operation of natural gas stations, including consumers and potential modifications of existing facilities; and iii) conversion equipment suppliers for vehicles. The regulation is administered by the Industrial and Commerce Ministry ("ICM") who supervises commercial and industrial activities in the Dominican Republic as well as the fuels and natural gas commercialization to the end users.

Key Financial Drivers

The financial weakness of the three state-owned distribution companies is due to low collection rate and high levels of non-technical losses and the delay in payments for the electricity supplied by generators. At times when outstanding balances have accumulated, AES Dominicana has accepted payment through other means, such as government bonds, in order to reduce their outstanding receiveables. There can be no guarantee that alternative collection methodologies will always be an avenue available for payment options.

The supply and price of fuel is actively managed to meet forecasted dispatch, comply with physical obligations to offtakers, and provide flexibility with negotiated contractual terms to redirect supply and cover proper credit requirements.

Other SBU Businesses

Puerto Rico

AES Puerto Rico is a coal-fired cogeneration plant utilizing Circulating Fluidized Bed Boiler ("CFB") technology. We have installed capacity that represents approximately 14% of the system capacity. The baseload plant is a Qualifying Facility under the U.S. PURPA. The Puerto Rico Electric Power Authority ("PREPA"), a public corporation that operates as a state-owned monopoly, governs Puerto Rico's electric market. PREPA supplies virtually all of the electric power consumed in the Commonwealth and generates, transmits and distributes electricity to 1.5 million customers. PREPA is governed by the Public Utility Regulatory Policies Act. PREPA purchases 454 MW of dependable generating capacity from our AES Puerto Rico coal-fired cogeneration facility located in Guayama under a long-term PPA, which expires in 2027. AES Puerto Rico represents a low-cost energy alternative for PREPA and reduces its current dependency on oil for energy production with our CFB technology plant.

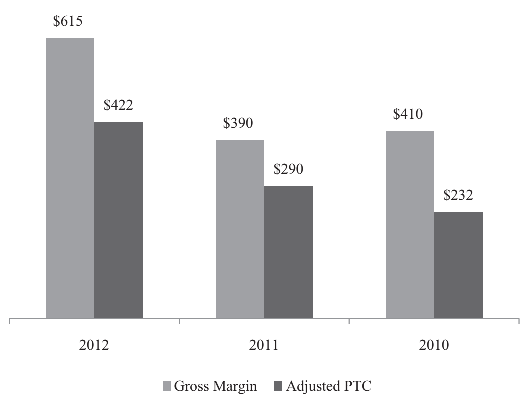
El Salvador

AES is the majority owner of four of the five distribution companies operating in El Salvador: CAESS, with about 40% market share; CLESA, with 16% market share; EEO, with 9% market share; and DEUSEM, with 2% market share. The distribution companies are operated by AES on an integrated basis under a single management team. AES El Salvador's territory covers 80% of the country. AES El Salvador accounted for 3,888 GWh of market energy purchases during 2012, or about 66% market share of the country's total market energy purchases of 5,883 GWh.

The sector is governed by the General Electricity Law, and the general and specific orders issued by Superintendencia General de Electricidad y Telecomunicacions ("SIGET" or "The Regulator"). The Regulator, jointly with the distribution companies in El Salvador, completed the tariff reset process in December 2012 and defined the tariff calculation to be applicable for the next five years (2013-2017).

EMEA SBU

Our EMEA SBU has generation facilities in nine counties and distribution utilities in three countries. Our EMEA operations accounted for 17%, 10% and 11% of AES consolidated gross margin and 20%, 16% and 15% of AES consolidated adjusted PTC (a non-GAAP measure) in 2012, 2011 and 2010, respectively. The percentages shown are the contribution by each SBU to gross adjusted PTC, i.e. the total adjusted PTC by SBU, before deductions for Corporate.



The following table provides highlights of our EMEA operations:

Countries	Bulgaria, Cameroon, Jordan, Kazakhstan, Netherlands, Nigeria, Spain, Turkey, Ukraine and United Kingdom
Generation Capacity	9,396 gross MW (6,100 proportional MW)
Utilities Penetration	2.2 million customers (11,235 GWh)
Generation Facilities	25 (including 4 under construction)
Utilities Businesses	4
Key Generation Businesses	Maritza, Kazakhstan, Kilroot, Ballylumford and Ebute

Operating installed capacity of our EMEA SBU totaled 9,396 MW, of which 29%, 21% and 11% is located in Kazakhstan, United Kingdom and Cameroon, respectively. Set forth in the table below is a list of our EMEA SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
Maritza	Bulgaria	Coal	690	100%	2011
St. Nikola	Bulgaria	Wind	156	89%	2010
Bulgaria Subtotal			*846*		
Dibamba	Cameroon	Heavy Fuel Oil	86	56%	2009
Cameroon Subtotal			*86*		
Amman East	Jordan	Gas	380	37%	2009
Jordan Subtotal			*380*		
Ust—Kamenogorsk CHP	Kazakhstan	Coal	1,354	100%	1997
Shulbinsk HPP(1)	Kazakhstan	Hydro	702	0%	1997
Ust—Kamenogorsk HPP(1)	Kazakhstan	Hydro	331	0%	1997
Sogrinsk CHP	Kazakhstan	Coal	301	100%	1997
Kazakhstan Subtotal			*2,688*		
Elsta(2)	Netherlands	Gas	630	50%	1998
Netherlands Subtotal			*630*		
Ebute	Nigeria	Gas	294	95%	2001
Nigeria Subtotal			*294*		
Cartagena(2),(3)	Spain	Gas	1,199	14%	2006
Spain Subtotal			*1,199*		
Kocaeli(2),(4)	Turkey	Gas	158	50%	2011
Bursa(2),(4)	Turkey	Gas	156	50%	2011
Kepezkaya(2),(4)	Turkey	Hydro	28	50%	2010
Kumkoy(2),(4)	Turkey	Hydro	18	50%	2011
Damlapinar(2),(4)	Turkey	Hydro	16	50%	2010
Istanbul (Koc University)(2),(4)	Turkey	Gas	2	50%	2011
Turkey Subtotal			*378*		
Ballylumford	United Kingdom	Gas	1,246	100%	2010
Kilroot(5)	United Kingdom	Coal/Oil	662	99%	1992
Drone Hill	United Kingdom	Wind	29	100%	2012
North Rhins	United Kingdom	Wind	22	100%	2010
United Kingdom Subtotal			*1,959*		
EMEA Total			8,460		

(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 February 2012, AES sold 80% of its interest in the business.
(4) Joint Venture with Koc Holding.
(5) Includes Kilroot Open Cycle Gas Turbine ("OCGT").

Under construction

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Expected Year of Commercial Operation
Kribi	Cameroon	Gas	216	56%	2013
Cameroon Subtotal			*216*		
IPP4 Jordan	Jordan	Heavy Fuel Oil	247	60%	2014
Jordan Subtotal			*247*		
Sixpenny Wood	United Kingdom	Wind	20	100%	2013
Yelvertoft	United Kingdom	Wind	16	100%	2013
United Kingdom Subtotal			*36*		
EMEA Total			499		

Set forth below is a list of our EMEA utility businesses:

Business	Location	Approximate Number of Customers Served as of 12/31/2012	GWh Sold in 2012	AES Equity Interest (Percent, Rounded)	Year Acquired
Sonel	Cameroon	816,000	3,569	56%	2001
Cameroon Subtotal		*816,000*	*3,569*		
Ust-Kamenogorsk Heat Nets[(1)]	Kazakhstan	96,000	—	0%	
Kazakhstan Subtotal		*96,000*	—		
Kievoblenergo	Ukraine	882,000	5,248	89%	2001
Rivneenergo	Ukraine	412,000	2,418	84%	2001
Ukraine Subtotal		*1,294,000*	*7,666*		
EMEA Total		2,206,000	11,235		

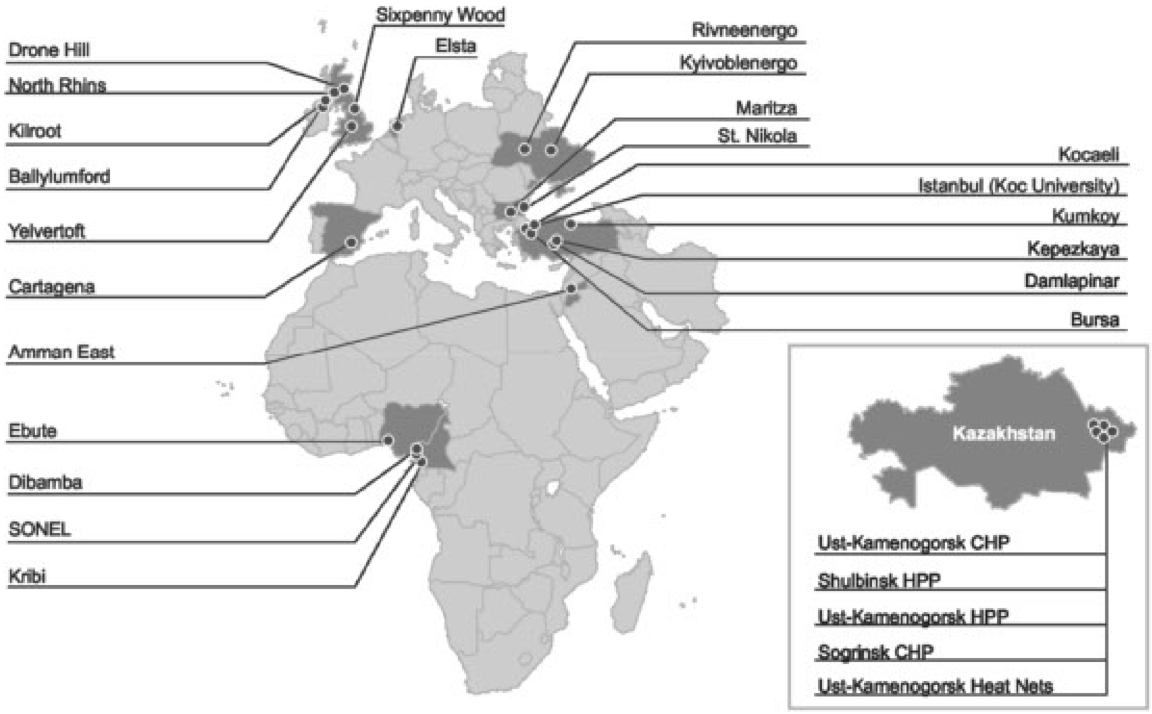
(1) AES operates these businesses through management agreements and owns no equity interest in these businesses. These agreements are due to expire in the middle of 2013 and we intend to enter into discussions for extension. Ust-Kamenogorsk Heat Nets provide transmission, and distribution of heat, with a total heat generating capacity of 224 Gcal.

Set forth below is information on the generation facilities of Sonel:

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.

The following map illustrates the location of our EMEA facilities:



EMEA Businesses

Bulgaria

Business Description. Our Maritza plant is a 690 MW lignite-fuel plant that was commissioned in June 2011. Maritza is the only coal-fired power plant in Bulgaria that is fully compliant with the EU Industrial Emission Directive, which comes into force in 2016. Maritza's entire power output is contracted with Natsionala Elektricheska Kompania ("NEK") under a 15-year PPA, capacity and energy based, with a fuel pass-though. The lignite is supplied under a 15-year fuel supply contract.

AES also owns an 89% interest in the St. Nikola wind farm with 156 MW of installed capacity. St. Nikola was commissioned in March 2010. Its entire power output is contracted with NEK under a 15-year PPA.

Market Structure

The maximum market capacity in 2012 was approximately 13 GW. In 2012 capacity increased significantly with the addition of approximately 1 GW of renewable energy capacity. Thermal power plants, representing 48% of total generation capacity and 53% of the total output, and the nuclear plant representing 16% of the total generation capacity and 35% of the total output, are the dominant suppliers in the Bulgarian electricity market. Hydroelectric accounts for 23% of total capacity and 9% of total output.

Regulatory Framework

Electricity Regulation. The electricity sector in Bulgaria operates under the Energy Act 2004 that allows the sale of electricity to take place freely at negotiated prices, at regulated prices between parties or on the organized market. In practice an organized market for trading electricity has not yet evolved, which leaves the regulated transactions market, the bilateral contracts market and the balancing market as the principal means for the wholesale electricity. The regulated component of the wholesale electricity market remains significant mainly driven by the government's objectives to ensure low prices for protected consumers and to support the generation from renewable energy sources and cogeneration that is sold at feed-in tariff rates.

In order to aid the creation of a competitive environment, the Bulgarian energy market has undergone a long liberalization process since 2000 by unbundling NEK, a state-owned vertically integrated utility that was responsible for generation, transmission and distribution in the entire country. Distribution and a majority of generation assets were separated and most of them privatized while NEK retained responsibility for the hydroelectric power plant assets and the ownership and operation of the transmission system. However, all these structural changes were not accompanied by the development of a trading market and hence, to date, NEK remains the main wholesale buyer for power generated in Bulgaria.

In connection with Bulgaria's entry 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, and could pose a problem with respect to the liberalization of Bulgaria's electricity markets. The long-term PPAs in the Bulgarian market account for less than 20% of total generation capacity. If the Commission determines that the PPAs are anticompetitive, they could take actions up to and including termination of Maritza's PPA, which could have a material adverse impact on our results of operations and financial condition.

NEK is undergoing a restructuring process in order to comply with EU's Third Energy package. As part of the restructuring it is expected that transmission system assets will be transferred from NEK to Electricity System Operator ("ESO") and that is expected to negatively impact the financial creditworthiness of NEK. If NEK is unable to keep the same credit rating as when they entered into the PPA, it could have an adverse impact on the business' financing arrangement.

Key Financial Drivers

Plant availability is the largest single performance driver of this business. Another key driver is NEK, the offtaker's, ability to meet the terms of the existing long-term PPA.

Kazakhstan

Business Description. Our businesses account for approximately 4% of the total annual generation in Kazakhstan. Of the total capacity of 2,688 MW, 1,033 MW is hydroelectric that operates under a concession agreement until the beginning of October 2017 and 1,655 MW of coal-fired capacity is owned outright. The thermal plants are designed to produce heat with electricity as a co—or by-product.

The Kazakhstan businesses act as merchant plants for electricity sales by entering into bilateral contracts directly with consumers for periods of generally no more than one year. There are no opportunities for the plants to be in contracted status, as there is no central offtaker, and the few businesses that could take a whole plant's generation tend to have in-house generation capacity. The 2012 amendments to the Electricity Law state that a centrally organized capacity market will be established by 2016, but the offtaker still only signs annual contracts.

The hydroelectric plants are run-of-river and rely on river flow and precipitation (particularly snow). Due to the presence of a large multi-year storage dam upstream and a growing season minimum river flow rate agreement with Russia (downstream) the plants are protected against significant downside risk to their volume in years with low precipitation.

Ust Kamenogorsk CHP provides heat to the city of Ust Kamenogorsk through the city heat network company (Ust Kamenogorsk Heat Nets). These sales could be considered as contracted, since Ust Kamenogorsk Heat Nets has no alternative suppliers.

Market Structure

The Kazakhstan electricity market totals approximately 19,000 MW, of which 14,500 MW is available. The bulk of the generating capacity in Kazakhstan is thermal, with coal as the main fuel. As coal is abundantly available in Kazakhstan, most plants are designed to burn local coal. The geographical remoteness of Kazakhstan, in combination with its abundant resources, means that coal prices are not reflective of world coal prices (current delivered cost is less than $20 per metric ton). In addition, the Government closely monitors coal prices, due to their impact on the price of socially necessary heating and on electricity tariffs.

Regulatory Framework

All Kazakhstan generating companies sell electricity at or below their respective tariff-cap level. These tariff-cap levels have been fixed by the Kazakhstan Ministry of Industry and New Technology ("MINT") for the period 2009-2015 for each of the thirteen groups of generators. These groups were determined by the MINT based on a number of factors including type of plant and fuel used.

In July 2012, Kazakhstan enacted various amendments to its Electricity Law. Among the amendments was a requirement for all profits generated by electricity producers during the years 2013-2015 to be reinvested. Accordingly, the business will be unable to pay dividends for the period 2013-2015. Under the amended Electricity Law, electricity producers must, on an annual basis, enter into investment obligation agreements ("IOA's") with the MINT detailing their annual investment obligations. These annual IOAs must equal the sum of the upcoming year's planned depreciation and profit. Selection of investment projects for the IOAs is at the discretion of electricity producers, but the MINT has the right to reject submitted IOA proposals. An electricity producer without an IOA executed by the MINT may not charge tariffs exceeding its incremental cost of production, excluding depreciation. On December 20, 2012, the MINT executed IOA with all four AES generators in Kazakhstan, which allow revenue at the tariff-cap level, but all generated cash will need to be reinvested.

Heat production in Kazakhstan is also regulated as a natural monopoly. The heat tariffs are set on a cost-plus basis by making an application to the Regulator (DAREM). Tariffs can either be for one-year or multi-year periods.

Key Financial Drivers

The main business drivers are plant availability, tariff caps set by MINT and weather conditions.

Nigeria

Business Description. Our Ebute business of 294 MW operates under a capacity-based PPA contract with the state-owned entity Power Holding Company of Nigeria ("PHCN"), which expires in a few years. Earnings are driven primarily by capacity payments paid under the PPA. It sells power generated by a nine unit barge-mounted gas turbine system, with fuel currently supplied by the offtaker. However, due to the ongoing PHCN privatization process, in the future, Ebute will have to source its own fuel, although with the ability to pass some or all of its cost through the tariff.

Ebute's cash flow is supported by a $60 million letter of credit issued by a credit-worthy institution in order to secure timely payment of amounts due to Ebute under the PPA. The letter of credit may be drawn upon at any time for any overdue payment of 15 days and can be fully drawn if not renewed timely.

Market Structure

Nigeria is currently characterized by significant underinvestment in the electricity sector, with only 3.2 GW of dependable capacity. Businesses and higher income residents depend primarily on privately owned diesel generators. The state-owned entity PHCN holds a large majority of the electricity market share, with private power generating companies accounting for the rest. The private power generating companies are represented by three IPPs, one of which is AES Nigeria.

Regulatory Framework

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. On the basis of the current reforms embodied in the Nigeria Power Sector Reform Roadmap, a number of new regulatory and/or other governing bodies will be established to regulate the industry.

Key Financial Drivers

Plant availability is the single largest driver of Ebute's financial performance.

United Kingdom

Business Description

AES' generation businesses in the United Kingdom operate in two different markets – the Irish Single Electricity Market ("SEM") for the businesses located in Northern Ireland (1,908 MW) and UK wholesale electricity market for the businesses located in Scotland and England (87 MW).

The Northern Ireland generation facilities consist of two plants within the Belfast region. Our Kilroot plant is a 662 MW coal-fired plant, and our Ballylumford plant is a 1,246 MW gas-fired plant. These plants provide approximately 78% of the Northern Ireland power demand and 18% of the combined demand for the island of Ireland. One of the Ballylumford stations of 540 MW does not meet the standards of the EU Industrial Emission Directive discussed below, which will most likely result in closing at the end of 2015, unless further investment is committed.

Kilroot is a merchant plant that bids into the SEM market and derives its value from the capacity payments offered through the SEM Capacity Payment Mechanism, the variable margin when scheduled in merit and the margin from constrained dispatch (when dispatched out of merit to support the system in relation to the wind generation, voltage and transmission constraints). In addition to the above, value is also secured from ancillary services.

Ballylumford is partially contracted (600 MW) under a PPA with Northern Ireland Electricity ("NIE") that ends in 2018 with an extension at offtaker's option to 2023, with the remaining capacity bid into the SEM market. Ballylumford derives its value, with an almost equal contribution, from availability payments received under the PPA and capacity payments offered through the SEM Capacity Payment Mechanism. Additionally, Ballylumford receives revenue from constrained dispatch.

The Scotland and England businesses consist of four wind generation facilities totaling approximately 87 MW, two of which are already in operation and two are due to come on line by the end of May 2013. A further pipeline of approximately 250 MW has been submitted for permitting consents. The wind projects sell their power to licensed suppliers in the United Kingdom market under long-term PPAs for the full output, generating half of the revenues from the United Kingdom wholesale electricity market and half from green certificates.

Market Structure

The majority of the generation capacity in the SEM is represented by gas-fired power plants, which results in market sensitivity to gas prices. Wind generation capacity represents approximately 20% of the total generation capacity. The governments of Northern Ireland and the Republic of Ireland plan further increases in renewables. Market availability and liquidity of hedging products is weak, reflecting the limited size and immaturity of the market, the predominance of vertical integration and lack of forward pricing. There are essentially three products (baseload, mid-merit and peaking) which are traded between the two largest generators and suppliers.

Regulatory Framework

Electricity Regulation. The SEM is an energy market, which was established in 2007 and is completely distinct from the United Kingdom power market. It is based on a gross mandatory pool, within which all generators with a capacity higher than 10 MW must trade the physical delivery of power. Generators are dispatched based on merit order.

In addition, there is a capacity payment mechanism to ensure that sufficient generating capacity is offered to the market. The capacity payment is derived from a regulated Euro-based capacity payment pool, established a year ahead by the Regulatory Authority. Capacity payments are based on the declared availability of a unit and have a degree of volatility to reflect seasonal influences, demand and the actual out-turn of generation declared available over each trading period.

Environmental Regulation

The European Commission adopted in 2011 the Industrial Emission Directive (“IED”) that establishes the emission limit values (“ELVs”) for SO_2, NOx and dust emissions to be complied with starting in 2016. This affects our Kilroot business which currently complies with the dust ELV, but for the SO_2, and particularly NOx, significant investment will be required.

The IED provides for two options that may be implemented by the EU member states – Transitional National Plan (“TNP”) or Limited Life Time Derogation. The TNP would allow the power plants to continue to operate between 2016-2020, being exempt from compliance with ELVs, but observing a ceiling set for maximum annual emissions that is established looking at the last 10 years average emissions and operating hours. Under the TNP, power plants will have to implement investment plans that will ensure compliance by 2020. The Limited Life Time Derogation will allow plants to run between 2016 and 2023, being exempt from the compliance with ELVs, but for no more than 17,500 hours.

Key Financial Drivers

For our business in the SEM market the key drivers are availability and commodity prices (gas and coal), and regulatory changes. The contracted plants’ financial results are influenced by availability.

In the United Kingdom, part of our revenue stream is indexed to short-term electricity market prices, which are largely influenced by delivered gas prices.

The future value of the Northern Ireland businesses will depend on gas price volatility and any alterations to the SEM market structure and payment mechanism.

Other Businesses

With regard to our other businesses, in 2012 we sold 80% of our interest in Cartagena, a 1,199 MW gas-fired plant in Spain operating under a long-term contract, and as a result Cartagena is reported as equity in earnings of affiliates.

In Turkey, we currently own in partnership with Koc Holding, 378 MW of hydroelectric and gas plants. During 2012, we finalized the split of the joint venture with I.C. Energy on the hydroelectric assets, and following that, three hydroelectric plants were transferred into the partnership with Koc Holding. The Turkey hydro businesses fall under the renewable feed-in tariff, while the gas assets are dispatched in the market. Our businesses in Turkey are operated under a joint venture structure; they are reported as equity in earnings of affiliates.

In Jordan we have a partial ownership in a 380 MW oil/gas-fired plant, fully contracted with the national utility under a 25-year PPA. In 2012, we concluded the financing for a platform expansion project, a 247 MW oil fired peaker that will start construction in the first quarter of 2013. The project is similar in structure with Amman East and is fully contracted with the national utility under a 25-year PPA.

In Netherlands, we own 50% of Elsta facility, a 630 MW gas fired plant that supplies steam and electricity under the long-term contracts ending 2018. Elsta's income is reported as equity in earnings.

In Ukraine we are involved in the distribution and sale of electricity through Kievoblenergo in which AES has 89% equity interest and Rivneenergo in which AES has 84% equity interest. The distribution and supply tariffs for all distribution companies in Ukraine are established by the National Energy Regulatory Commission on an annual basis. In January 2013, AES signed a Sale Purchase Agreement for the sale of both Ukrainian distribution entities.

In Cameroon we are involved in the generation, transmission, distribution and sale of electricity through AES Sonel, an integrated utility, and two Independent Power Producers (IPP).

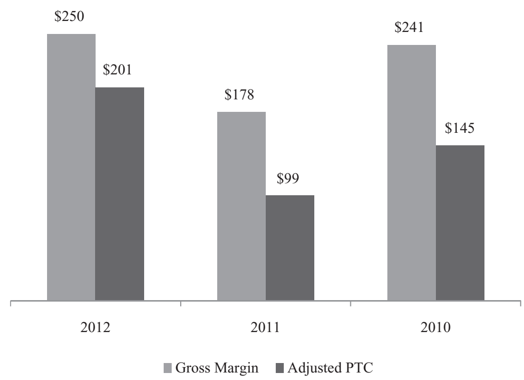
We own 56% of AES Sonel with the remaining 44% held by the Republic of Cameroon. AES Sonel is the only electricity provider in Cameroon. It is regulated by the Agence de Régulation de Secteur d'Electricité (ARSEL). AES Sonel operates and maintains 936 MW of generation, two interconnected transmission networks and distributes electricity to more than 800,000 primarily residential customers. AES Sonel operates under a 20-year concession agreement that was signed in July 2001. Electricity demand has increased at an average annual rate of 6%, since 2001, and 7.5%, since 2010. Growth will continue especially in the residential segment.

In addition, AES is part owner and sole operator of two IPPs; Dibamba Power Development Company ("DPDC"), with a 86 MW heavy fuel oil plant, and Kribi Power Development Company ("KPDC"), with a 216 MW gas/light fuel oil plant, currently under commissioning. DPDC and KPDC have the same ownership structure; 56% AES and 44% Republic of Cameroon. Contracts at KPDC and DPDC are primarily capacity-based with Government protections. DPDC has a 20-year tolling agreement with AES Sonel and KPDC has a 20-year PPA with AES Sonel and a 20-year gas supply agreement with the Government-owned Societe Nationale des Hydrocarbures ("SNH")

With the commissioning of Kribi, AES will have 1,238 MW of generation in Cameroon—almost 100% of the country's total capacity; of which 58% is hydroelectric, 17% gas, 16% heavy fuel oil, and 9% diesel.

Asia SBU

Our Asia SBU has generation facilities in four countries. Our Asia operations accounted for 7%, 4% and 6% of AES consolidated gross margin and 10%, 6% and 9% of AES consolidated adjusted PTC (a non-GAAP measure) in 2012, 2011 and 2010, respectively. The percentages shown are the contribution by each SBU to gross adjusted PTC, i.e. the total adjusted PTC by SBU, before deductions for Corporate.



The following table provides highlights of our Asia operations:

Countries	China, India, Philippines, Sri Lanka and Vietnam
Generation Capacity	1,337 gross MW (1,021 proportional MW)
Generation Facilities	6 (including 1 under construction)
Key Businesses	Masinloc, OPGC, Saurashtra and Mong Duong II

Operating installed capacity of our Asia SBU totals 1,337 MW, of which 51%, 36% and 13% located in the Philippines, India and Sri Lanka respectively. Set forth below in the table is a list of our Asia SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
Chengdu(1)	China	Gas	50	35%	1997
China Subtotal			*50*		
OPGC(1)	India	Coal	420	49%	1998
Saurashtra	India	Wind	39	100%	2012
India Subtotal			*459*		
Masinloc	Philippines	Coal	660	92%	2008
Phillipines Subtotal			*660*		
Kelanitissa	Sri Lanka	Diesel	168	90%	2003
Sri Lanka Subtotal			*168*		
Asia Total			1,337		

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

Under construction

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Expected Year of Commercial Operation
Mong Duong II	Vietnam	Coal	1,240	51%	2015

The following map illustrates the location of our Asia facilities:

Asia Businesses

Philippines

Business Description

In April 2008, AES acquired the 660 MW Masinloc coal-fired power plant, located in Luzon. Subsequent to the acquisition, AES performed a substantial rehabilitation program that was completed in 2010, resulting in improvements in reliability, environmental emissions, and plant safety performance. Generating capacity was improved from 430 MW at acquisition to 630 MW, and plant availability increased from 74% at acquisition to current 93%.

Approximately 90% of Masinloc's peak capacity is contracted through medium—to long-term bilateral contracts primarily with Meralco, several electric cooperatives and a large industrial customer.

Market Structure

The Philippine power market is divided into three grids representing the country's three major island groups—Luzon, Visayas and Mindanao. Luzon (which includes Manila and is the country's largest island) is interconnected with Visayas and represents 84% of the total demand of both regions. Luzon and Visayas together have an installed capacity of 12,704 MW.

There is diversity in the mix of the Luzon-Visayas generation, with coal accounting for 28%, natural gas for 20%, hydroelectric for 19%, geothermal generation for 13%, and the remaining 20% from oil-based generating plants which are either dispatched by the system operator only during system emergencies or dispatched by the market during peak demand.

The primary customers for electricity are private distribution utilities, electric cooperatives, and to a lesser extent large industrial customers. Approximately 90%-95% of the system's total energy requirement is being sold/purchased through medium to long term bilateral contracts (3-5 years, with renewal extensions). The remaining 5%-10% of energy is sold through the Wholesale Electricity Spot Market ("WESM"), which is the real time, bid-based and hourly market for energy where the sellers and the buyers adjust their differences between their production/demand and their contractual commitments.

Regulatory Framework

Electricity Regulation. The Philippines has divided its power sector into generation, transmission, distribution and supply under 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 conducted primarily through medium-term bilateral contracts between generation companies and customers specifying the volume, price and conditions for the sale of energy and capacity, which are approved by the Energy Regulatory Commission ("ERC"). Power is traded in the WESM which operates under a gross pool, central dispatch and net settlement protocols. Parties to bilateral contracts settle their transactions outside of the WESM and distribution companies or electricity cooperatives buy their imbalance (i.e., power requirements not covered by bilateral contracts) from the WESM. Distribution utilities and electric cooperatives are allowed to pass on to their end-users the ERC-approved bilateral contract rates, including WESM purchases.

Other Regulatory Considerations. EPIRA established 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 distribution companies or electricity cooperatives providing non-discriminatory wire services. The ERC has issued a joint statement with DOE declaring December 26, 2012 as the commencement date of the Retail Competition and Open Access. The period from December 26, 2012 to June 25, 2013 is a transition period with full implementation scheduled for June 26, 2013. There is no expected material adverse impact expected and we may purchase additional capacity from the market in 2013 to take advantage of this regulatory opportunity.

Environmental Regulation

The Renewable Energy Act of 2008 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 has not set the final figure. If the regulations are implemented, our businesses in the Philippines could be affected by requirements requiring all generators to supply a portion of their generation from renewable energy resources.

Key Financial Drivers

The key drivers of the business are Masinloc's availability, system reliability, demand growth, and reserve margins.

Other Businesses

India

Business Description

Our generation business in India consists of two plants: the Odisha Power Generation Corporation ("OPGC") coal-fired plant and Saurashtra wind plant. OPGC is a 420 MW coal plant located in the state of Odisha. AES acquired 49% of OPGC in 1998, with the remaining 51% owned by the state of Odisha. Saurashtra is a 100% owned 39 MW wind plant located in the state of Gujarat, which commenced operations in early 2012.

Our generation businesses have long-term PPAs with state utilities. OPGC has a 30-year PPA with GRIDCO Limited expiring in 2026. The PPA is comprised of a capacity payment based on fixed parameters and a variable component comprised of fuel costs, where actual fuel costs are a pass-through. Saurashtra has a 25-year PPA with the Gujarat State Utility.

Vietnam

Business Description

The Mong Duong II power project is a 1,240 MW plant being constructed under a Build, Operate, and Transfer ("BOT") agreement in Quang Ninh province of Vietnam. The project is currently the largest private sector power project in the country. AES-VCM Mong Duong Power Company Limited ("the BOT Company"), a limited liability joint venture established by the affiliates of AES (51%), Posco Energy Corporation (30%) and China Investment Corporation (19%). The BOT Company has a PPA term of 25 years with Vietnam Electricity ("EVN"). At the end of the term of the PPA, the company will be transferred to the Government in accordance with the BOT contract. Upon reaching commercial operations, EVN will have exclusive rights on the facility's entire capacity and energy. Vietnam National Coal-Mineral Industries Group ("Vinacomin"), the stated-owned entity, is the project's coal supplier under a 25-year coal supply agreement.

The tariff has two components: Capacity charge and the foreign component of Operation and Maintenance Charge ("O&M"), which are paid in U.S. Dollars and the local component of O&M and fuel charge are paid in Vietnam Dong. In addition, the U.S. Dollar and Vietnam Dong component of O&M are linked to a published Consumer Price Index of the U.S. and Vietnam respectively. Fuel costs in general are pass-through elements in the fuel charge.

The project is currently under construction and is scheduled to commence operations in the second half of 2015.

Financial Data by Country

The table below presents information, by country, about our consolidated operations for each of the three years ended December 31, 2012, 2011 and 2010, respectively, and property, plant and equipment as of December 31, 2012 and 2011, 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	
	2012	2011	2010	2012	2011
	(in millions)				
United States[1]	$ 3,764	$ 2,113	$ 1,952	$ 7,663	$ 7,730
Non-U.S.:					
Brazil[2]	5,788	6,640	6,355	5,756	5,896
Chile	1,679	1,608	1,355	2,993	2,781
Argentina[3]	857	979	771	278	293
El Salvador	850	752	648	267	268
Dominican Republic	761	674	535	670	662
Philippines	559	480	501	800	766
United Kingdom[4]	505	587	364	579	523
Ukraine	491	418	356	112	94
Cameroon	457	386	422	989	901
Colombia	453	365	393	383	384
Mexico	397	404	409	759	779
Bulgaria[5]	369	251	44	1,611	1,624
Puerto Rico	293	298	253	570	581
Panama	266	189	194	1,069	1,040
Sri Lanka	169	140	100	8	22
Kazakhstan	151	145	138	141	86
Jordan	121	124	120	222	216
Spain[6]	119	258	411	—	—
Hungary[7]	—	—	10	—	—
Qatar[8]	—	—	—	—	—
Pakistan[9]	—	—	—	—	—
Oman[10]	—	—	—	—	—
Vietnam	—	—	—	887	138
Other Non-U.S.[11]	92	112	112	156	217
Total Non-U.S.	14,377	14,810	13,491	18,250	17,271
Total	$18,141	$16,923	$15,443	$25,913	$25,001

(1) Excludes revenue of $39 million, $374 million and $662 million for the years ended December 31, 2012, 2011 and 2010, respectively, and property, plant and equipment of $619 million as of December 31, 2011, related to Eastern Energy, Thames, Ironwood, and Red Oak which were reflected as discontinued operations and assets held for sale in the accompanying Consolidated Statements of Operations and Consolidated Balance Sheets. Additionally property, plant and equipment excludes $25 million and $45 million as of December 31, 2012 and 2011, respectively, related to wind turbines which were reflected as assets held for sale in the accompanying Consolidated Balance Sheets.

(2) Excludes revenue of $124 million and $118 million for the years ended December 31, 2011 and 2010, respectively, related to Brazil Telecom, which was reflected as discontinued operations in the accompanying Consolidated Statements of Operations.

(3) Excludes revenue of $102 million and $116 million for the years ended December 31, 2011 and 2010, respectively, related to our Argentina distribution businesses, which were reflected as discontinued operations in the accompanying Consolidated Statements of Operations.

(4) Excludes revenue of $5 million, $17 million and $21 million for the years ended December 31, 2012, 2011 and 2010, respectively, related to carbon reduction projects, which were reflected as discontinued operations in the accompanying Consolidated Statements of Operations.

(5) Our wind project in Bulgaria started operations in 2010 and Maritza started operations in June 2011.

(6) Excludes property, plant and equipment of $620 million as of December 31, 2011, related to Cartagena, which was reflected as assets held for sale in the accompanying Consolidated Balance Sheet.

(7) Excludes revenue of $18 million, $219 million and $287 million for the years ended December 31, 2012, 2011 and 2010, respectively, and property, plant and equipment of $5 million as of December 31, 2011, related to Borsod, Tiszapalkonya and Tisza II, which were reflected as discontinued operations and assets held for sale in the accompanying Consolidated Statements of Operations and Consolidated Balance Sheets.

(8) Excludes revenue of $129 million for the year ended December 31, 2010, related to Ras Laffan, which was reflected as discontinued operations in the accompanying Consolidated Statements of Operations.

(9) Excludes revenue of $299 million for the year ended December 31, 2010, related to Lal Pir and Pak Gen, which were reflected as discontinued operations in the accompanying Consolidated Statements of Operations.

(10) Excludes revenue of $62 million for the year ended December 31, 2010, related to Barka, which was reflected as discontinued operations in the accompanying Consolidated Statements of Operations.

(11) Excludes revenue of $1 million for each of the years ended December 31, 2012 and 2011, related to alternative energy and carbon reduction projects, which were reflected as discontinued operations in the accompanying Consolidated Statements of Operations.

Environmental and Land Use Regulations

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. For a discussion of the laws and regulations of individual countries within each SBU where our subsidiaries operate, see discussion within Item 1. of this Form 10-K under the applicable SBUs.

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—*Environmental 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, Regulations and Protocols

In 2012, the Company's subsidiaries operated electric power generation businesses which had total approximate direct CO_2 emissions of 78.9 million metric tonnes, approximately 39.9 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. 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 which the Company's subsidiaries 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 results of operations, financial condition and cash flows.

United States—Federal Greenhouse Gas 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. It is uncertain if any GHG emissions legislation will be voted on and passed by the U.S. Congress in 2013 or 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 now 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 such construction or modifications. 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, any new sources of GHG emissions that emit over 100,000 tons per year of GHG emissions, in addition to any modification that result in GHG emissions exceeding 75,000 tons per year, require PSD review and are 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.

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 (the "D.C. Circuit"). On June 26, 2012, a three-judge panel of the D.C. Circuit upheld the Endangerment Finding, Tailoring Rule and the Motor Vehicle Rule, and on December 20, 2012, the D.C. Circuit denied the industry petitioners' motion for a rehearing. The industry petitioners may petition the U.S. Supreme Court for appeal, which petition the Court may accept or deny.

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 and on March 27, 2012, the EPA proposed a rule that would establish NSPS for CO_2 emissions for new fossil-fueled EUSGUs larger than 25 megawatts ("MW"). The proposed rule was published in the Federal Register on April 13, 2012, and the period for public comments expired on June 12, 2012. The EPA is considering the public comments. The proposed rule would not apply to modified or existing EUSGUs, including the Company's subsidiaries' existing power plants. The EPA may propose regulations that would apply to modified or existing EUSGUs at a later date. However, the EPA has not yet announced a timetable for such regulations. It is impossible to estimate the impact and compliance costs associated with any future EPA regulations applicable to modified or existing EUSGUs until such regulations are finalized; however, the impact, including the compliance costs, could be material to our consolidated financial condition or results of operations.

United States—State Greenhouse Gas 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, nine 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 that the costs to the Company of compliance with RGGI could be approximately $3.0 million for 2013. Under the current 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.

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 2012, of the approximately 39.9 million metric tonnes of CO_2 emitted in the United States by the businesses operated by our subsidiaries (ownership adjusted), approximately 1.4 million metric tonnes were emitted by the Warrior Run business, our only business located in a state participating in RGGI. 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 business that is subject to RGGI to the extent that it 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 $1.93 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 2012. Based on these assumptions, the Company estimates that the RGGI compliance costs could be approximately $3.0 million for 2013. 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 began on January 1, 2013, and initially covers emissions from electricity generating facilities, large industrial sources with annual emissions greater than 25,000 metric tons of CO_2 equivalent, and imported electricity. Emitters are 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 are issued free allowances and merchant facilities are required to bid for allowances at auctions. The initial auction of GHG allowances resulted in the sale of all offered allowances at a price slightly above the floor price of $10. 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.

California is also a member of the Western Climate Initiative ("WCI"), an organization that also includes 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. California and Quebec are the only two WCI members to have adopted cap-and-trade programs to date. California has proposed regulations enabling it to link its cap-and-trade program with Quebec's program, which would establish common allowance auctions and permit mutual acceptance of compliance instruments. 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. 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. If the Company's subsidiaries in California were required to bear such compliance costs, it could have a material impact on such subsidiaries' results of operations, financial conditions or cash flows.

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 1990 levels or less 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. Act 234 also required the Hawaii Department of Health to adopt rules to achieve reductions of GHG emissions based upon the recommendations and findings of the Task Force. Pursuant to Act 234, the Hawaii Department of Health published for public comment proposed rules that would initiate the regulation of GHGs in Hawaii. To achieve the stated goal of reducing and maintaining statewide GHG levels at 1990 levels by 2020, such proposed rules:

- require 25% reductions of facility-wide 2010 GHG levels by 2020 from Hawaii's largest existing emitters, which includes AES Hawaii;
- require each affected source to prepare a GHG reduction plan within nine months after the adoption of the proposed rule; and
- initiate the collection of annual GHG fees (initially $0.12 per ton of CO_2 equivalent emitted).

We have estimated that AES Hawaii's initial GHG fee under the proposed rules with respect to 2012 emissions would be approximately $170,000. The period for public comment expired on January 13, 2013. The Hawaii Department of Health is considering the public comments.

At this time, other than the estimated impact of CO_2 compliance noted above for its businesses that are subject to RGGI or the proposed Hawaii Department of Health rules, the Company has not estimated the costs of compliance with other actual or potential United States federal, state or regional CO_2 emissions reduction legislation or initiatives, such as WCI and MGGRA. This is 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. We have not estimated the costs of compliance with 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 of existing sources or MGGRA have yet to be proposed or finalized, if these GHG-related initiatives are proposed and 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 or the payment for GHG emissions allowances 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 applicability of any emission rate limits imposed on existing or modified EUSGUs and the impacts of such limits on the operation of fossil fuel-fired electric generating units;
- 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.

International Greenhouse Gas Regulations and Protocols

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 ("EU ETS") 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 expired at the end of 2012. In December 2012, the annual United Nations conference of the parties to the Kyoto Protocol was held in Doha, Qatar ("COP 18"). COP 18 resulted in the publication of the Doha Amendment that provides for a second commitment period, running for eight years from January 1, 2013 to December 31, 2020, and an overall commitment to reduce GHG emissions during that period by 18% from 1990 levels. The Doha Amendment will be effective, for the parties who ratify it, on the 90th day after three-quarters of the parties to the Kyoto Protocol have ratified it. COP 18 also resulted in commitments to work toward a universal climate change agreement on GHG emissions reductions, to be adopted by 2015. At present, the Company cannot predict whether compliance with the second 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.

Since January 2005, large combustion plants and other large industrial installations located in the EU have been subject to the EU ETS. Established by Directive 2003/87/EC, the EU ETS requires EU member states ("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 terminated 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. Directive 2003/87/EC did not dictate how these allocations were to be made, and the approved NAPs varied in their allocation methodologies.

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 will 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 began 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 four thermal electric power generation facilities within three Member States which are subject to the EU ETS. During the first and second trading periods, achieving and maintaining compliance with the requirements of the EU ETS did not have a material impact on the consolidated operations or results of the Company.

The risk and benefit associated with achieving compliance with the EU ETS 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. For those facilities owned by the Company's subsidiaries that are directly subject to EU ETS compliance risk, the majority of allowances have so far been allocated free of charge under the NAP, with any additional allowances or alternative compliance credits (for example, certified emission reduction units generated by the Clean Development Mechanism) being capable of being bought in the market at relatively low cost due to oversupply issues. The impact of the third phase of trading is uncertain. Though the price of allowances and alternative compliance credits is currently low, the European Commission is proposing to take measures to counteract the oversupply issue and bolster the price of allowances. Accordingly, at this time, the Company cannot determine whether achieving and maintaining compliance with the EU ETS for the third trading period will have a material impact on its consolidated operations or financial results.

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% 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; these were intended to 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 overall target of 20% 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.

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.

Other United States Environmental and Land Use Legislation and Regulations

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"). Certain applicable 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"). The CSAPR would have required 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, the rule would have required additional SO_2 emission reductions of 73% and additional NO_X reductions of 54% from 2005 levels.

Many states, utilities and other affected parties filed petitions for review, challenging the CSAPR before the D.C. Circuit. On August 21, 2012, a three-judge panel of the D.C. Circuit vacated the CSAPR and required EPA to continue administering CAIR pending the promulgation of a valid replacement to the CSAPR. The Company's subsidiaries will continue to meet their CAIR requirements by virtue of existing pollution control equipment combined with the purchase of emission allowances, when needed. On October 5, 2012, EPA, several states and cities, as well as environmental and health organizations, filed petitions with the D.C. Circuit requesting a rehearing of the case by all of the judges of the D.C. Circuit. On January 24, 2013, the D.C. Circuit issued orders denying all of the outstanding petitions for rehearing and rehearing en banc of the CSAPR decision. The EPA has 90 days from the issuance of the D.C. Circuit's mandate to file a petition for certiorari with the Supreme Court.

If EPA does not seek Supreme Court review, the Agency must begin developing a replacement rule. At this time, we cannot predict the impact that such a replacement transport rule would have on the Company. However, such replacement rule could have a material adverse 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, among other substances, 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") 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 MATS standards for each pollutant regulated under the rule. The rule requires all coal-fired power plants to comply with the applicable MATS 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 scrubbers or comparable control technologies designed to remove SO_2 and which also remove some acid gases. However, there are other improvements to such control technologies that may be needed even at these plants to assure compliance with the MATS 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. This was followed by a notification by Duke Energy to PJM, dated February 1, 2012, of a planned April 1, 2015 deactivation of this unit. With respect to DP&L's Hutchings Station, a six unit coal-fired power plant with 365 MW of total capacity, DP&L has notified PJM that it intends to deactivate Hutchings Station's Units 1 and 2 by 2015 and that Unit 4, currently out of service due to equipment failure, would not be available for service any time earlier than 2014. On January 11, 2013, DP&L provided a similar notice to PJM with respect to Hutchings Units 3, 5 and 6, noting a deactivation date of June 1, 2015. The plans to deactivate units at the Hutchings Station are not irreversible, but none of these units are equipped with the advanced environmental control technologies needed to comply with the MACT standards and the cost of compliance with the MACT standards or conversion to natural gas for these units does not appear to be economically justified. The combination of existing and expected environmental regulations, including the MATS, make it likely that IPL will temporarily or permanently retire or repower 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 estimates additional expenditures related to the MATS rule for environmental controls for its baseload generating units to be approximately $511 million through 2016, excluding demolition costs. In June of 2012, IPL filed a petition and a request for a Certificate of Public Convenience and Necessity for this amount (including supplemental testimony). These filings detail the controls IPL plans to add to each of its five baseload units. IPL is seeking and expects to recover through its environmental rate adjustment mechanism all operating and capital expenditures related to compliance; however, there can be no assurance that IPL will be successful in that regard. Recovery of these costs is expected through an Indiana statute, which allows for 100% recovery of qualifying costs through a rate adjustment mechanism.

Several lawsuits challenging the MATS rule have been filed and consolidated into a single proceeding before the United States Court of Appeals for the District of Columbia Circuit. We cannot predict the outcome of this litigation. The aggregate 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 adverse 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.

DP&L's Stuart Station and Hutchings 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 adverse 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. The statute requires compliance within five years after the EPA approves the relevant state implementation plan ("SIP") or issues a federal implementation plan, 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 electricity generating unit ("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 accepted comments on this proposal until February 25, 2012; however, because the D.C. Circuit vacated CSAPR on August 21, 2012, the EPA had indicated that it will await the results of its petition for rehearing before it takes further action on this proposal. EPA now will have to withdraw its proposed rule establishing compliance with CSAPR as equal to BART. EPA may now require states to adopt SIPs to those states that had relied on the previous rules that equated CAIR and CSAPR to BART.

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.

On July 17, 2012, the EPA announced that it would delay issuance of the final rule until no later than June 27, 2013. 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. The State Water Resources Board is currently reviewing the implementation plans and has requested additional information to assist with its evaluation. 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.

On January 7, 2013, the Ohio EPA issued an NPDES permit for J.M. Stuart Station. The primary issues involve the temperature and thermal discharges from the Station including the point at which the water quality standards are applied, i.e., whether water quality standards apply at the point where the Station discharge canal discharges into the Ohio River, or whether, as the EPA alleges, the discharge canal is an extension of Little Three Mile Creek and the water quality standards apply at the point where water enters the discharge canal. In addition, there are a number of other water-related permit requirements established with respect to metals and other materials contained in the discharges from the Station. The NPDES permit establishes interim standards related to the thermal discharge for 54 months that are comparable to current levels of discharge by Stuart Station. Permanent standards for both temperature and overall thermal discharges are established as of 55 months after the permit is effective, except that an additional transitional period of approximately 22 months is allowed if compliance with the permanent standards is to be achieved through a plan of construction and various milestones on the construction schedule are met. DP&L is still analyzing the NPDES permit, but it is believed that there is a strong potential that compliance will require capital expenses that are material to DP&L. The cost of compliance and the timing of such costs is uncertain and may vary considerably depending on a compliance plan that would need to be developed, the type of capital projects that may be necessary, and the uncertainties that may arise in the likely event that permits and approvals from other governmental entities would likely be required to construct and operate any such capital project. DP&L has appealed various aspects of the final permit to the Environmental Review Appeals Commission. The outcome of such appeal is uncertain.

On August 28, 2012, the Indiana Department of Environmental Management issued NPDES permits to the IPL Petersburg, Harding Street and Eagle Valley generating stations, which became effective in October 2012. NPDES permits regulate specific industrial wastewater and storm water discharges to the waters of Indiana under Sections 402 and 405 of the U.S. Clean Water Act. These permits set new levels of acceptable metal effluent water discharge, as well as monitoring and other requirements designed to protect aquatic life, with full compliance required by October 2015. IPL is seeking a two-year extension; however, we cannot predict whether such extension will be approved. IPL is conducting studies to determine what operational changes and/or additional equipment will be required to comply with the new limitation. In developing its compliance plans, IPL must make assumptions about the outcomes of future federal rulemaking with respect to coal combustion byproducts, cooling water intake and wastewater effluents. In light of the uncertainties at this time, we cannot predict the impact of these regulations on our consolidated results of operations, cash flows, or financial condition, but it is expected to be material to IPL. Recovery of these costs is expected through an Indiana statute, which allows for 80% recovery of qualifying costs through a rate adjustment mechanism and the remainder through a base rate case proceeding; however, there can be no assurances that IPL would be successful in that regard.

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. 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, the North American Electric Reliability Corporation ("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.

Indiana Tree Trimming Regulation. In July 2012, the Indiana Utility Regulatory Commission ("IURC") issued a final order regarding the tree trimming practices, which was later approved by the Indiana governor and attorney general and became law in October 2012. IPL is implementing procedures to ensure it appropriately complies with the requirements of the new rule that addresses notification, dispute resolution and other activities associated with its vegetation management practices. The requirements of the new ruling are similar to current practices. However, the actual cost impact of the rule will not be known until IPL has experience operating under its terms.

Other International Environmental Regulations

In Europe, the Company is, and will continue to be, required to reduce air emissions from our facilities to comply with applicable EU Directives, including the new IED, which incorporates Directive 2001/80/EC (referred to as the Large Combustion Plant Directive, or the "LCPD"). The Company's coal plants in Europe are either exempt from the LCPD/IED due to their size or possess the abatement technology required to be in compliance with the LCPD/IED, except for AES Ballylumford's 'B Station,' with respect to which AES Ballylumford has elected under the LCPD/IED to retire from operations by 2015 rather than invest in the abatement technology required to comply with the LCPD/IED.

Progress in implementation of the IED varies from Member State to Member State—the deadline for implementation having passed on January 7, 2013. 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 “limited lifetime derogation plan.” Each operator has until January 1, 2014 to submit a declaration to the relevant permitting authority indicating whether it intends to take advantage of a limited lifetime derogation plan. AES generation businesses in each Member State will be required to comply with the relevant measures taken to implement the IED. 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 adverse impact on the Company’s consolidated operations or results.

Customers

We sell to a wide variety of customers. No individual customer accounted for 10% or more of our 2012 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, 2012, we employed approximately 25,000 people.

Executive Officers

The following individuals are our executive officers:

Andrés R. Gluski, 55 years old, has been President, CEO and a member of our Board of Directors since September 2011 and is Chairman of the Strategy and Investment Committee of the Board. Prior to assuming his current position, Mr. Gluski served as Executive Vice President and 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 since 2005 and AES Brasiliana since 2006 and serves on the Board of AES Entek, a joint venture between AES and Koc Holdings that will develop and operate power projects in Turkey. Mr. Gluski is also on the Boards of Cliffs Natural Resources, The Council of Americas, US Spain Council and The Edison Electric Institute. Mr. Gluski is a magna cum laude graduate of Wake Forest University and holds an M.A and a Ph.D. in Economics from the University of Virginia.

Elizabeth Hackenson, 52 years old, was named Chief Information Officer (“CIO”) and Senior Vice President of AES in October 2008. Prior to assuming her current position, Ms. Hackenson was the Senior Vice President and CIO at Alcatel-Lucent from 2006 to 2008, where she managed the development of technology programs for Applications, Operations and Infrastructure. Previously, she also served as the Executive Vice President and CIO for MCI from 2004 to 2006. MCI was a Fortune 50 company, with a diversified telecom portfolio employing 55,000 employees worldwide. Her corporate tenure has spanned several Fortune 100 companies including, British Telecom (Concert), AOL (UUNET) and EDS. She served in a variety of senior management positions, working on the management and delivery of information technology services to support business needs across a corporate-wide enterprise. Ms. Hackenson serves on the Boards of Dayton Power & Light and its parent company DPL, Inc. Indianapolis Power & Light and its parent company IPALCO, AES Sul and AES Chivor. She also serves on several Boards outside of AES, including Serena (a privately held company owned by Silver Lake Partners), HP Board of Advisors and is a Strategic Advisor to the Paladin Group.

Brian A. Miller, 47 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., AES Solar Power, LLC, and AES Solar Power PR, LLC, joint ventures between AES and Riverstone Holdings LLC. 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 Dayton Power & Light Company and its parent company, DPL, Inc. He is also a member of the Board of AES Chivor. 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.

Thomas M. O'Flynn, age 52, has served as Executive Vice President and Chief Financial Officer ("CFO") of the Company since September of 2012. Previously, Mr. O'Flynn served as Senior Advisor to the Private Equity Group of Blackstone, an investment and advisory group and held this position from 2010 to 2012. During this period, Mr. O'Flynn also served as Chief Operating Officer and Chief Financial Officer of Transmission Developers, Inc. (TDI), a Blackstone-controlled company that develops innovative power transmission projects in an environmentally responsible manner. From 2001 to 2009, he served as the Chief Financial Officer of PSEG, a New Jersey-based merchant power and utility company. He also served as President of PSEG Energy Holdings from 2007 to 2009. From 1986 to 2001, Mr. O'Flynn was in the Global Power and Utility Group of Morgan Stanley. He served as a Managing Director for his last five years and as head of the North American Power Group from 2000 to 2001. He was responsible for senior client relationships and led a number of large merger, financing, restructuring and advisory transactions. Mr. O'Flynn serves as a member of the Boards of AES Gener, AES Solar Energy, Ltd., AES Solar Power, LLC, and AES Solar Power PR, LLC, joint ventures between AES and Riverstone Holdings LLC, Dayton Power & Light and its parent company, DPL, Inc. He is also currently on the Board of Directors of the New Jersey Performing Arts Center. Mr. O'Flynn has a BA in economics from Northwestern University and an MBA in Finance from the University of Chicago.

Andrew Vesey, 57 years old, serves as COO and Executive Vice President since November of 2012. In this position, he leads AES' Global Operations Portfolio. Mr. Vesey has held numerous positions with AES, including Executive Vice President and Chief Operating Officer, Global Utilities from October of 2011 to November of 2012; Executive Vice President and Regional President of Latin America and Africa from April of 2009 through October of 2011; 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 Indianapolis Power & Light, IPALCO, Dayton Power & Light and DPL, Inc Boards and serves on the Boards of AES Sonel and AES Gener. In addition, Mr. Vesey is a member of the Board of the Corporate Council on 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.

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 21, 2012.

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. 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.

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

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 in 2013. 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, 2012, we had approximately $21.4 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 12 – *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, tax sharing, 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 or may be prohibited altogether. 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'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, 2012, we had approximately $21.4 billion of outstanding indebtedness on a consolidated basis, of which approximately $6.0 billion was recourse debt of The AES Corporation and approximately $15.4 billion was non-recourse debt. In addition, we have outstanding guarantees, indemnities, 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 $1.4 billion at December 31, 2012. 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 thereunder 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;
- under certain circumstances, 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 material debt of material subsidiaries;
- the loss or impairment of investor confidence in the Company; or
- foreclosure on the assets that are pledged under the non-recourse 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.

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;
- 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 could 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.

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 can be volatile and often reflect the fluctuating cost of fuels such as coal, natural gas or oil in addition to other factors described below. 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;
- general economic conditions in areas where we operate which impact energy consumption: and
- bidding behavior and market bidding rules.

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. 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 Argentine Peso, Brazilian Real, Chilean Peso, Colombian Peso, Euro 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 difference in 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 the United States 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, which was finalized in December of 2012.

At DPL and IPL, the degree of exposure to commodity price changes is dependent upon the regulatory framework under which the business operates. DPL is subject to a regulatory framework that differs materially from IPL, and is described in more detail in Item 1.—Business—*US SBU Businesses* of this Form 10-K. The IPL generating assets benefit from the regulated load served and are subject to fluctuation to the extent we have excess capacity available to sell to wholesale markets. The DPL generating assets do not have a captive load that acts as a hedge against collapsing dark spreads, and dependent upon the outcome of the rate case may be separated entirely from the distribution business.

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. 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. A number of our businesses are facing challenges associated with regulatory changes. For example, the government of the Dominican Republic is expected to end 2012 with a deficit of $4.6 billion, an amount that represents roughly 6.8 percent of the country's GDP and twice the deficit in 2011, which could impact our ability to collect approximately $200 million in receivables owed to our businesses in the country and to collect receivables we generate in the future. In order to address these issues, the Dominican government has recently announced several tax initiatives including: (i) elimination of step-down in tax rate from 29% to 25% for 2013, (ii) imposition of a 10% dividend withholding tax and (iii) an increase in the Value Added Tax from 16% to 18%, any or all of which could result in increased taxes at our businesses in the country. In Argentina, the deterioration of certain economic indicators such as non-receding inflation, increased government deficits and foreign currency accessibility combined with the potential devaluation of the local currency and the potential fall in export commodity prices could cause significant volatility in our results of operations, cash flows, the ability to pay dividends, and the value of our assets. As of December 31, 2012, the total of AES' long-lived assets in Argentina was $564 million, including long-term receivables of $316 million. In addition, recent actions by the Argentine government may indicate deeper government intervention in the local economy. For example, on April 16, 2012, the Argentine government expropriated 51% of the assets of the country's largest oil company. The statute used to expropriate the oil company is not applicable to our businesses in Argentina. However, potential deteriorating economic conditions or further government action could have a material impact on the Company or its financial statements. In addition, the government has instituted capital controls that have banned the purchase of dollars, making it difficult to get cash generated by our businesses out of the country.

Outside of Latin America, in Cameroon, a new law governing electricity was promulgated on December 14, 2012. The new law provides that a state-owned transmission system operator will be in charge of operation, maintenance and investments in infrastructure, whereas the existing concession agreement grants to AES SONEL the responsibility of maintenance, operations and investments in transmission. The impacts of the new law are not clear, however, there is a risk that: (i) we may not receive profits related to our investment of almost 100 billion CFA ($201 million) invested in transmission and/or (ii) the new state owned operator may not be able to mobilize the funds necessary for important investments and for adequate maintenance of the system, which could impact the efficiency and/or productivity of our businesses. In Kazakhstan, the government recently passed certain amendments to the Electricity Law that support the government's view that all energy producers have to reinvest all of their profits into renovation or construction of new plant assets during the years 2013-2015. The ability to charge ceiling tariffs established by the government is conditional upon the execution of annual investment agreements with the Ministry of Industry and New Technologies ("MINT"), which now has broad discretion to reject agreements. An energy producer lacking an investment agreement with MINT may charge tariffs no higher than its cost of producing energy (excluding depreciation). The new law would limit the ability of our subsidiaries in Kazakhstan to provide dividends to The AES Corporation and may require those subsidiaries to invest in projects which do not generate returns consistent with our internal targets.

The above examples illustrate the regulatory challenges we may face. Further information on these matters, as well as additional regulatory matters, is included in Item 1.—Business of this Form 10-K.

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 risk mitigation and/or 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 this infrastructure or at the facilities of our subsidiaries, including as a result of third parties intentionally or unintentionally disrupting this infrastructure or 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 risk mitigation and/or 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 actions of third parties or other 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, along with other safety hazards associated with our operations, 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. For example, 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 sales and supply contracts, which helps these businesses to manage risks by reducing the volatility associated with power and input costs and providing a stable revenue and cost structure. 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 of our generation plants range from one 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 adversely impact our strategy by resulting in costs that exceed revenue, which 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. 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 may 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. The current focus is on our offtaker, NEK. Further information on the EC investigation is set forth in Item 1.—Business—*EMEA SBU Businesses—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.

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 thirty-one defined benefit plans, five 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 15 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 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.

In certain cases, our subsidiaries may enter into obligations in the development process even though the subsidiaries have not yet secured financing, power purchase arrangements, or other aspects of the development process. For example, in certain cases, our subsidiaries may instruct contractors to begin the construction process or seek to procure equipment even where they do not have financing or a power purchase agreement in place (or conversely, to enter into a power purchase, procurement or other agreement without financing in place). If the project does not proceed, our subsidiaries may remain obligated for certain liabilities even though the project will not proceed. Development is inherently uncertain and we may forgo certain development opportunities and we may undertake significant development costs before determining that we will not proceed with a particular project. 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 our subsidiaries share operational, management, investment and/or other control rights with our joint venture partners. In many cases, we may exert influence over the joint venture pursuant to a management contract, by holding positions on management committees and/or through certain limited governance rights, such as rights to veto significant actions. However, we do not always have this type of influence over the project or business in every instance and we may be dependent on our joint venture partners to operate, manage, invest or otherwise control such projects or businesses. Our joint venture partners may not have the level of experience, technical expertise, human resources, management and other attributes necessary to operate these projects or businesses optimally, and they may not share our business priorities.

The approval of joint venture partners also may be required for us to receive distributions of funds from jointly owned entities or to transfer our interest in projects or businesses. The control or influence exerted by our joint venture partners may result in operational management and/or investment decisions which are different from the decisions our subsidiaries would make if they operated independently and could impact the profitability and value of these joint ventures.

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. If BNDES decides to commence a sales process for their equity interests in Brasiliana and if a third party offer has been received, 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. 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. In addition, in Bulgaria, new regulatory rules have the effect of reducing the feed in tariffs in our wind business by imposing grid access fees and this has led to a default under the financing agreements for this business. In 2011, tariffs for certain of our European solar businesses were reduced, and could be reduced further. The carrying value of our investment in AES Solar Energy Ltd., whose primary operations are in Europe, was $126 million at December 31, 2012. In addition, several other 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. Even where available, many of our renewable projects in the emerging markets sell power under a Feed-in-Tariff or make money through the sale of Certified Emission Reductions ("CERs") or European Union Allowances ("EUAs"), and the price of the CERs and EUAs are volatile but not necessarily unavailable.

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.

As of December 31, 2012, the Company had approximately $2 billion of goodwill, which represented approximately 5% of our total assets on its Consolidated Balance Sheet. Goodwill is not amortized, but is evaluated for impairment at least annually, or more frequently if impairment indicators are present. We could be required to evaluate the potential impairment of goodwill outside of the required annual evaluation 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. These types of events and the resulting analyses could result in goodwill impairment, which could substantially affect our results of operations for those periods. Additionally, goodwill may be impaired if our acquisitions do not perform as expected. See the risk factor *"Our acquisitions may not perform as expected."* for further discussion. For example, the Company recognized goodwill impairment of $ 1.82 billion related to its acquisition of DPL during the second half of 2012, which was primarily driven by deteriorating business and operating conditions. See Note 10—*Goodwill and Other Intangible Assets* in Item 8 of this Form 10-K for further information.

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, or impact our ability to make collections or otherwise impact our operations, 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.

We have not realized the anticipated benefits and cost savings of the DPL acquisition, and DPL continues to face business and regulatory challenges.

In November 2011, we acquired DPL Inc., owner of DP&L. To date, we have not realized the benefits that we anticipated at the time of acquisition and, in 2012, we recorded a goodwill impairment charge of approximately $1.82 billion for DPL. In addition, during 2012, DPL obtained a waiver and amendment to certain of its loan documents, which included new covenants and various restrictions, including restrictions on DPL's ability to distribute dividends to The AES Corporation. DPL continues to face a number of business and regulatory challenges.

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. On October 5, 2012, DP&L filed an Electric Service Plan ("ESP") with the PUCO to establish SSO rates that were to be in effect starting January 2013. The plan requested approval of a non-bypassable charge that is designed to recover $138 million per year for five years from all customers. DP&L also requested approval of a switching tracker that would measure the incremental amount of switching over a base case and defer the lost value into a regulatory asset which would be recovered from all customers beginning January 2014. The ESP states that DP&L plans to file on or before December 31, 2013 its plan for legal separation of its generation assets. The ESP proposes a three year, five month transition to market, whereby a wholesale competitive bidding structure will be phased in to supply generation service to SSO customers. The PUCO is currently reviewing the filing and an evidentiary hearing is scheduled to begin on March 11, 2013. The outcome of the proceeding is uncertain and could have a material impact on our results. The PUCO authorized that the rates being collected prior to December 31, 2012 would continue until the new ESP rates go into effect. See Item 1.—Business—*US SBU, Businesses—DPL, Inc.* for further information.

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 CRES Providers in DP&L's service territory for retail generation service has resulted in the loss of existing customers and reduced revenues and could result in the loss of additional customers and further reduced revenues as well as increased costs to retain existing customers or attract new 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 DPL's service territory, and additional CRES Providers entering DPL's territory.
- DPL 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 DPL's business and financial results and could adversely affect DPL's ability to refinance certain debt (or to do so on favorable terms) which is due in the near or intermediate term DP&L has scheduled debt maturities in 2013 totaling approximately $771 million (including a $200 million revolving credit facility and a $101 million letter of credit facility). Certain of these maturities are currently subject to a first mortgage. It is DP&L's intention to refinance the first mortgage bonds under similar terms that would also allow for the potential legal separation of its generation assets. While DP&L and its advisors believe that such a refinancing under favorable terms is probable, there can be no assurances that the prospective creditors might require pricing, terms and/or conditions that are worse than those currently in place. Any of the foregoing could have a material adverse effect on the Company.

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.

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 at 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 are 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 and it may be difficult to predict the impact of the regulations on our businesses. 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. However, even with the exemption, 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.

Our business in the United States is subject to the provisions of various laws and regulations administered in whole or in part by the FERC and NERC, including PURPA, the Federal Power Act, and the EPAct 2005. Actions by the FERC, NERC 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 Independent Transmission System Operator, Inc., PJM Interconnection, L.L.C., ISO New England, Inc., the New York Independent System Operator, Inc. (“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 EPAct 2005 to remove the purchase/sale obligations of individual utilities on a case-by-case basis. While this 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.

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 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 American Electric 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.

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 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 26 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, 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 2012, the Company's subsidiaries operated businesses which had total CO_2 emissions of approximately 78.9 million metric tonnes, approximately 39.9 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 18.7 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 adverse 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 is no federal legislation 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. The EPA may in the future propose regulations that would apply to modified or existing EUSGUs. However, the EPA has not yet announced a timetable for such regulations.

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 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 and regulations that requires mandatory GHG reductions from several industrial sectors, including the electric power generation industry. See Item 1.—Business 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) and the proposed Hawaii regulations relating to the collection of fees on GHG emissions, 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 that was subject to RGGI in 2012. Of the approximately 39.9 million metric tonnes of CO_2 emitted in the United States by our subsidiaries in 2012 (ownership adjusted), approximately 1.4 million metric tonnes were emitted by our subsidiary in Maryland. 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 business that is subject to RGGI to the extent that it 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 $1.93 per allowance under RGGI. The source of this allowance price estimate was the clearing price in the recent RGGI allowance auction held in December 2012. Based on these assumptions, the Company estimates that the RGGI compliance costs could be approximately $3 million for 2013. 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. While the litigation mentioned has been dismissed, it is impossible to predict whether similar future 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 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, 2012.

In 1989, Centrais Elétricas Brasileiras S.A. ("Eletrobrás") filed suit in the Fifth District Court in the State of Rio de Janeiro ("FDC") 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 FDC found for Eletrobrás and in September 2001, Eletrobrás initiated an execution suit in the FDC to collect approximately R$1.3 billion ($626 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 FDC 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 FDC for further proceedings, holding that Eletropaulo's liability, if any, should be determined by the FDC. Eletropaulo's subsequent appeals were dismissed. In February 2010, the FDC 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. 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 directed the FDC to proceed accordingly. However, in December 2012, the FDC disregarded the AC's decision that the parties were entitled to full discovery and an expert appraisal of the issues prior to the resolution of the case and, instead, issued a decision finding Eletropaulo liable for the debt. The AC subsequently granted Eletropaulo's request to suspend the execution suit in the FDC and thereafter annulled the FDC's decision. The case will now return to the FDC for proceedings in accordance with the AC's April 2010 decision. If the FDC again finds Eletropaulo liable for the debt, after the amount of the alleged debt is determined, Eletrobrás will be entitled to resume the execution suit in the FDC. If Eletrobrás does so, Eletropaulo will be required to provide security for its alleged liability. In that case, if Eletrobrás requests the seizure of such security and the FDC 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 FDC against Eletrobrás and Eletropaulo seeking a declaration that CTEEP is not liable for any debt under the financing agreement. In December 2012, the FDC dismissed the 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 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 São 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 ($488 thousand) as of December 31, 2012, or pay an indemnification amount of approximately R$15 million ($7 million). Eletropaulo has appealed this decision to the Supreme Court and the Supreme Court affirmed the decision of the Appellate Court. Following the Supreme Court's decision, the case is being remanded to the court of first instance for further proceedings and to monitor compliance by the defendants with the terms of the decision.

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 2010, a 2-to-1 majority of the arbitral tribunal awarded the Company some of its costs relating to the arbitration. In August 2010, Gridco filed a challenge of the cost award with the local Indian court. The Company believes that it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In early 2002, Gridco made an application to the OERC requesting that the OERC initiate proceedings regarding the terms of OPGC's existing PPA with Gridco. In response, OPGC filed a petition in the Indian courts to block any such OERC proceedings. In early 2005, the Orissa High Court upheld the OERC's jurisdiction to initiate such proceedings as requested by Gridco. OPGC appealed that High Court's decision to the Supreme Court and sought stays of both the High Court's decision and the underlying OERC proceedings regarding the 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 has been awaiting further hearing. However, in December 2012, the parties executed a settlement agreement amending the PPA and resolving the dispute. The amended PPA is subject to regulatory approval.

In March 2003, the office of the Federal Public Prosecutor for the State of São Paulo, Brazil ("MPF") notified 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 ("SCJ") challenging the transfer. In November 2012, the SCJ ruled that the lawsuit must be returned to the FCSP. 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. 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. 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, and the State of Rio Grande do Sul Court of Appeals upheld the decision. As required by the injunction, CEEE has started the removal and disposal of the contaminants, which is ongoing, and Sul is not at risk to bear any of such remediation costs, which are estimated to be approximately R$14.7 million ($7 million). In November 2012, the inspections performed by the court expert and supervised by Sul confirmed that CEEE is fulfilling the injunction by removing the contaminants. The case is in the evidentiary stage awaiting the production of the court's expert opinion on several matters, including which of the parties had utilized the products found in the area.

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 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 appealed to the U.S. Court of Appeals for the Ninth Circuit. In September 2012, the Ninth Circuit affirmed the District Court's decision. The plaintiffs' subsequent petition for en banc review was denied by the Ninth Circuit. 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 March 2009, AES Uruguaiana Empreendimentos S.A. ("AESU") in Brazil 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. 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 April 2009, the Antimonopoly Agency in Kazakhstan 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 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) from UK HPP and KZT 1.3 billion ($9 million) from 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 October 2009, AES Mérida III, S. de R.L. de C.V. (AES Mérida), one of our businesses in Mexico, initiated arbitration against its fuel supplier and electricity offtaker, Comisión Federal de Electricidad ("CFE"), seeking a declaration that CFE breached the parties' power purchase agreement ("PPA") by supplying gas that did not comply with the PPA's specifications. Alternatively, AES Mérida requested a declaration that the supply of such gas by CFE is a force majeure event under the PPA. CFE disputed the claims. Although it did not assert counterclaims, in its closing brief CFE asserted that it is entitled to a partial refund of the capacity charge payments that it made for power generated with the out-of-specification gas. In July 2012, the arbitral Tribunal issued an award in AES Mérida's favor. In December 2012, CFE initiated an action in Mexican court seeking to nullify the award. AES Mérida believes it has meritorious defenses in that action; however, there can be no assurances that it will be successful.

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 and the Company is not able to estimate damages, if any, at this time. 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 again moved for partial dismissal of those amended complaints, and in May 2012, the Superior Court ruled on the motion in the November 2009 lawsuit, dismissing the plaintiff's claims for future medical monitoring expenses but declining to dismiss their claims under Dominican Republic Law 64-00. The Superior Court has not yet ruled on the motion for partial dismissal of the April 2010 lawsuit. The AES defendants filed an answer to the November 2009 lawsuit in June 2012. The Superior Court has stayed the remaining six lawsuits, as well as any subsequently filed similar lawsuits. The Superior Court has also ordered that, for the present, discovery will proceed only in the November 2009 lawsuit and will be limited to causation and exposure issues. 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. 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. In addition, in December 2010, the Contractor stopped commissioning of the power plant's two units, allegedly because of the purported 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 ($317 million) in the arbitration, unspecified damages for alleged injury to reputation, and other relief. The arbitral hearing on the merits was scheduled for March 2013, but recently was rescheduled by the arbitrators to a date to be determined. 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 ($510,370) and the suspension of AES Eletropaulo activities in the Park. As a response to this administrative procedure before the São Paulo State Environmental Authorities ("São 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 São 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 São Paulo EA, including a plan to recover the affected area by primarily planting additional trees. In March 2012, the State of São Paulo Prosecutor's Office of São Bernando do Campo initiated a Civil Proceeding to review the compliance by AES Eletropaulo with the terms of any possible settlement. AES Eletropaulo has had several meetings and field inspections to settle the details of the recovery project. AES Eletropaulo is currently awaiting the approval of the recovery project by the Park Administrator.

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. The Company is unable to estimate the alleged damages at this time. 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. In March 2012, the federal court granted the motion and dismissed the lawsuit. The plaintiffs appealed to the U.S. Court of Appeals for the Fifth Circuit. The appeal is fully briefed. 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 February 2011, a consumer protection group, S.O.S. Consumidores ("SOSC"), filed a lawsuit in the State of São Paulo Federal Court against Eletropaulo and all other distribution companies in the State of São Paulo, claiming that the distribution companies had overcharged customers for electricity. SOSC asserts that the distribution companies' tariffs had been incorrectly calculated by the Brazilian Regulatory Agency ("ANEEL"). ANEEL corrected the alleged error in May 2010. There are separate proceedings against ANEEL to determine whether the tariffs had been properly calculated. SOSC has moved for an injunction requiring tariffs to be corrected from the effective dates of the relevant concession contracts. Electropaulo has opposed that request on the ground that it did not wrongfully collect amounts from its customers, since its tariff was calculated in accordance with the concession contract with the Federal Government and ANEEL's rules. If it does not prevail in the lawsuit, Eletropaulo estimates that its liability to customers could be approximately R$855 million ($417 million). Electropaulo 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 (the "Municipality") filed 60 tax assessments in São Paulo administrative court against Eletropaulo, seeking approximately R$1.2 billion ($586 million) in services tax ("ISS") that allegedly had not been collected on revenues for services rendered by Eletropaulo. Eletropaulo estimates that, with interest, the amount at issue has increased to approximately R$2 billion ($1 billion). Eletropaulo has challenged the assessments 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 August 2012, Fondo Patrimonial de las Empresas Reformadas ("FONPER") (the Dominican instrumentality that holds the Dominican Republic's shares in Empresa Generadora de Electricidad Itabo, S.A. ("Itabo")) filed a criminal complaint against certain current and former employees of AES. The criminal proceedings include a related civil component initiated against Coastal Itabo, Ltd. ("Coastal") (the AES affiliate shareholder of Itabo) and New Caribbean Investment, S.A. ("NCI") (the AES affiliate that manages Itabo). FONPER asserts claims relating to the alleged mismanagement of Itabo and seeks approximately $270 million in damages. The Dominican District Attorney has accepted the criminal complaint and is investigating the allegations set forth therein. In September 2012, one of the individual defendants responded to the criminal complaint, denying the charges and seeking an immediate dismissal of same. Further, in August 2012, Coastal and NCI initiated an international arbitration proceeding against FONPER and the Dominican Republic, seeking a declaration that Coastal and NCI have acted both lawfully and in accordance with the relevant contracts with FONPER and the Dominican Republic in relation to the management of Itabo. Coastal and NCI also seek a declaration that the criminal complaint is a breach of the relevant contracts between the parties, including the obligation to arbitrate disputes. Coastal and NCI further seek damages from FONPER and the Dominican Republic resulting from their breach of contract. FONPER and the Dominican Republic have denied the claims. The AES defendants believe they have meritorious claims and defenses, which they will assert vigorously; however there can be no assurance that they will be successful in their efforts.

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

Stock Repurchase Program

The Company's Board of Directors recently increased the share buyback authorization by $300 million, all of which is available. Under the program, the Company may 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 it can be modified or terminated by the Company's Board at any time.

During the year ended December 31, 2012, shares of common stock repurchased under this plan totaled 24,790,384 at a total cost of $301 million plus a nominal amount of commissions (average of $12.16 per share including commissions), bringing the cumulative total purchases under the program to 58,715,189 shares at a total cost of $680 million, which includes a nominal amount of commissions (average of $11.58 per share including commissions).

There were no repurchases of common stock in the fourth quarter of 2012.

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 20, 2013, was $11.37, per share. The Company repurchased 24,790,384, 25,541,980 and 8,382,825 shares of its common stock in 2012, 2011 and 2010, respectively. The following tables set forth the high and low stock prices and cash dividends declared for the periods indicated:

	2012			2011	
	Sales Prices		Cash Dividends	Sales Prices	
	High	Low	Declared	High	Low
First Quarter	$14.01	$11.85	$ —	$13.40	$11.99
Second Quarter	13.25	11.64	—	13.50	12.03
Third Quarter	12.94	10.83	0.04	13.20	9.22
Fourth Quarter	11.25	9.52	0.04	12.24	9.00

Dividends

We commenced a cash dividend of $0.04 per share 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.

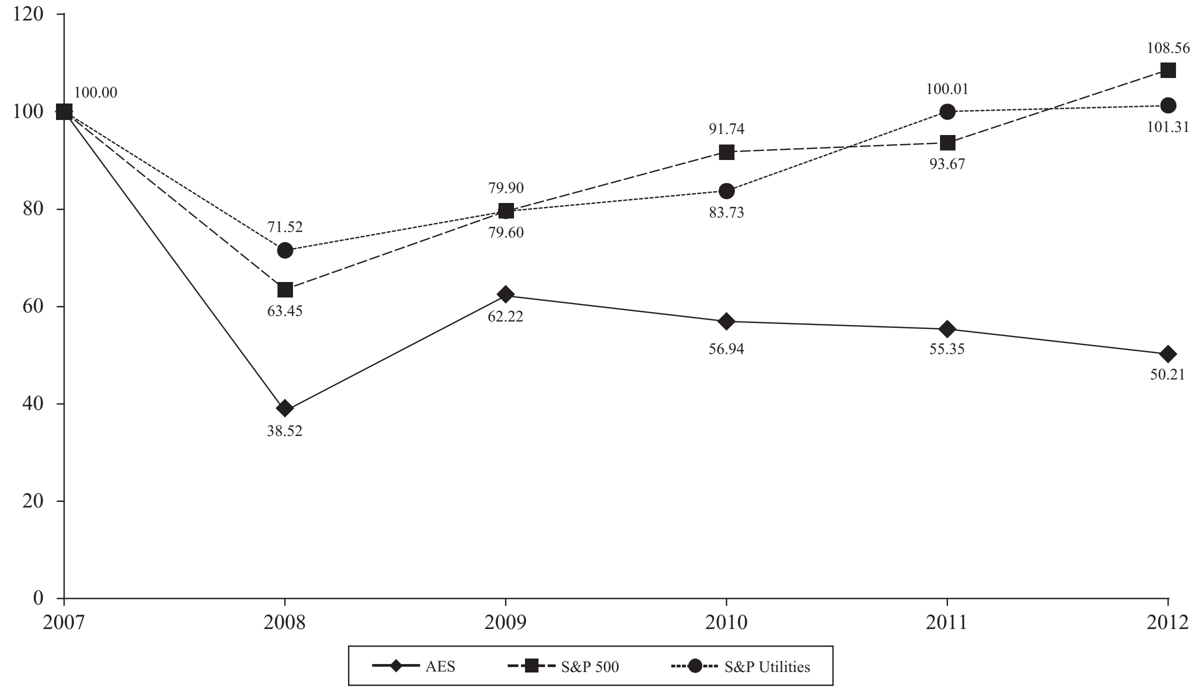
Holders

As of February 20, 2013, there were approximately 6,336 record holders of our common stock.

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, 2007 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.

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.—*Financial Statements and Supplementary Data* of this Form 10-K. The selected financial data for each of the years in the five year period ended December 31, 2012 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* of this Form 10-K and Note 26—Risks and Uncertainties to the Consolidated Financial Statements included in Item 8.—*Financial Statements and Supplementary Data* 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

	Year Ended December 31,				
Statement of Operations Data	**2012**	**2011[1]**	**2010**	**2009**	**2008**
	(in millions, except per share amounts)				
Revenue	$18,141	$16,923	$15,443	$12,716	$13,668
Income (loss) from continuing operations[2]	(360)	1,575	1,481	1,743	1,792
Income (loss) from continuing operations attributable to The AES Corporation, net of tax	(915)	492	496	663	1,049
Discontinued operations, net of tax	3	(434)	(487)	(5)	185
Net income (loss) attributable to The AES Corporation	$ (912)	$ 58	$ 9	$ 658	$ 1,234
Per Common Share Data					
Basic (loss) earnings per share:					
Income (loss) from continuing operations attributable to The AES Corporation, net of tax	$ (1.21)	$ 0.63	$ 0.64	$ 1.00	$ 1.57
Discontinued operations, net of tax	—	(0.56)	(0.63)	(0.01)	0.27
Basic earnings (loss) per share	$ (1.21)	$ 0.07	$ 0.01	$ 0.99	$ 1.84
Diluted (loss) earnings per share:					
Income (loss) from continuing operations attributable to The AES Corporation, net of tax	$ (1.21)	$ 0.63	$ 0.64	$ 0.99	$ 1.55
Discontinued operations, net of tax	—	(0.56)	(0.63)	(0.01)	0.27
Diluted earnings (loss) per share	$ (1.21)	$ 0.07	$ 0.01	$ 0.98	$ 1.82
Cash dividends declared	$ 0.08	—	—	—	—

	December 31,				
Balance Sheet Data:	**2012**	**2011 [1]**	**2010**	**2009**	**2008**
	(in millions)				
Total assets	$41,830	$45,346	$40,511	$39,535	$34,806
Non-recourse debt (noncurrent)	12,568	13,412	11,084	11,532	10,428
Non-recourse debt (noncurrent)—Discontinued operations	—	1,198	1,460	1,332	1,441
Recourse debt (noncurrent)	5,951	6,180	4,149	5,301	4,994
Cumulative preferred stock of subsidiaries	78	78	60	60	60
Retained earnings (accumulated deficit)	(264)	678	620	650	(8)
The AES Corporation stockholders' equity	4,569	5,946	6,473	4,675	3,669

(1) DPL was acquired on November 28, 2011 and its results of operations have been included in AES's consolidated results of operations from the date of acquisition. See Note 24—*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 of $1.9 billion, $190 million, $325 million, $142 million and $175 million for the years ended December 31, 2012, 2011, 2010, 2009 and 2008, respectively. See Note 10—*Goodwill and Other Intangible Assets* and Note 21—*Asset Impairment Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

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

Overview of Our Business

We are a diversified power generation and utility company organized into six market-oriented Strategic Business Units ("SBUs"): US (United States), Andes (Chile, Colombia, and Argentina), Brazil, MCAC (Mexico, Central America and the Caribbean), EMEA (Europe, Middle East and Africa), and Asia. For additional information regarding our business, see Item 1.—*Business* of this Form 10-K.

Our Organization — The management reporting structure is organized along six SBUs—led by our Chief Operating Officer ("COO"), who in turn reports to our Chief Executive Officer ("CEO"). Our CEO and COO are based in Arlington, Virginia. During the fourth quarter of 2012, the Company completed the restructuring of its operational management and reporting process into six SBUs. For financial reporting purposes, the Company has identified eight reportable segments based on the six SBUs. Accordingly, management's discussion and analysis of revenue and gross margin is organized as follows:

- US SBU
  - US—Generation segment
  - US—Utilities segment
- Andes SBU
  - Andes—Generation
- Brazil SBU
  - Brazil—Generation segment
  - Brazil—Utilities segment
- MCAC SBU
  - MCAC—Generation segment
- EMEA SBU
  - EMEA—Generation segment
- Asia SBU
  - Asia—Generation segment

Corporate and Other—The Company's EMEA and MCAC utilities as well as Corporate are reported within "Corporate and Other" because they do not require separate disclosure under segment reporting accounting guidance. See Note 17—*Segment and Geographic Information* included in Item 8.—*Financial Statements and Supplementary Data* for further discussion of the Company's segment structure used for financial reporting purposes.

Management's Priorities

Management is focused on the following priorities:

- Management of our portfolio of generation and utility businesses to create value for our stakeholders, including customers and shareholders, through safe, reliable, and sustainable operations and effective cost management;
- Driving our operating business to manage capital more effectively and to increase the amount of discretionary cash available for deployment into debt repayment, growth investments, shareholder dividends and share buybacks;
- Realignment of our geographic focus. To this end, we will continue to exit markets where we do not have a competitive advantage or where we are unable to earn a fair risk-adjusted return relative to monetization alternatives. In addition, we will focus our growth investments on platform expansions or opportunities to expand our existing operations; and
- Reduce the cash flow and earnings volatility of our businesses by proactively managing our currency, commodity and political risk exposures, mostly through contractual and regulatory mechanisms, as well as commercial hedging activities. We also will continue to limit our risk by utilizing non-recourse project financing for the majority of our businesses.

2012 Performance

During 2012, we executed on a comprehensive plan to improve operations, leverage our global scale and expertise, reduce our overhead and development costs, increase the sources of cash and the returns from our investments, and streamline the portfolio. These actions helped us to achieve our financial targets, despite challenges we faced at certain businesses, including AES Gener in Chile, Eletropaulo in Brazil and DP&L in the U.S.

Safe, Reliable and Sustainable Operations. In terms of operating performance, we benefitted from the first full year of contributions from our new businesses, which collectively represented more than 1,900 MW of capacity additions brought on-line with the oversight of our in-house construction management team.

We also benefitted from the results of our efforts to enhance the reliability of our generation fleet, particularly at Masinloc (Asia SBU) and Southland (US SBU). Further, we reduced our overhead and development costs by $90 million, exceeding our cost reduction target of $65 million. These positive drivers were partially offset by declines at our Andes and Brazil SBUs due to higher cost of replacement energy, lower prices and outages and in Chile and the negative impact of the tariff reset at Eletropaulo in Brazil. Further, we recognized a $1.82 billion goodwill impairment at DP&L in the U.S.

Improving Available Capital and Deployment of Discretionary Cash. In terms of enhancing the sources and uses of our discretionary cash, we improved our available capital by increasing operating cash flow and selling non-core assets. In 2012, we deployed our discretionary cash to pay down $531 million of recourse debt, repurchase 24.8 million shares for $301 million, at an average share price of $12.16, declared the first cash dividend since 1994 and invested $195 million in our subsidiaries to expand our existing facilities.

Realigning Our Geographic Focus. Finally, in an effort to streamline our portfolio, we sold eight assets for total equity proceeds to AES of more than $600 million and announced plans to exit five countries (China, Czech Republic, France, Hungary and Ukraine) where we did not have a compelling competitive advantage or where we are unable to earn a fair, risk-adjusted return, relative to monetization alternatives. To supplement our future growth, we commenced construction on 208 MW of platform expansion projects, including Guacolda V in Chile, Tunjita in Colombia and two wind projects in the United Kingdom.

Despite some challenges in 2012, we met our financial goals and completed the capital allocation commitments we made to our shareholders.

Earnings Per Share Results in 2012

	Year Ended December 31,		
	2012	**2011**	**2010**
	(in millions, except per share amounts)		
Diluted earnings per share from continuing operations	$(1.21)	$0.63	$0.64
Adjusted earnings per share (a non-GAAP measure)(1)	$ 1.24	$1.02	$0.91

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

During the year ended December 31, 2012, diluted earnings per share from continuing operations decreased principally due to the goodwill impairment expense of $2.41 per share recognized in connection with the interim goodwill impairment indicator identified during the third quarter at DPL, in the United States. See Item 8.—Financial Statements and Supplementary Data – Note 10 – *Goodwill and Other Intangible Assets* for further details.

Adjusted earnings per share, a non-GAAP measure, increased by 22% primarily due to the contribution of new businesses, lower general and administrative expenses and a lower share count, partially offset by the tariff reset at Eletropaulo and higher cost of replacement energy and lower prices in Chile.

Other Operating Highlights

	Year Ended December 31,		
	2012	**2011**	**2010**
	(in millions, except per share amounts)		
Revenue	$18,141	$16,923	$15,443
Gross margin	$ 3,714	$ 4,063	$ 3,820
Net (loss) income attributable to The AES Corporation	$ (912)	$ 58	$ 9
Adjusted pre-tax contribution (a non-GAAP measure)(1)	$ 1,377	$ 1,078	$ 955
Net cash provided by operating activities	$ 2,901	$ 2,884	$ 3,465
Dividends declared per common share	$ 0.08	$ —	$ —

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

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, 2012 compared to 2011 and 2010 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* below.

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, operations and maintenance costs, depreciation and amortization expense, bad debt expense and recoveries, general administrative and support costs (including employee-related costs directly associated with the operations of the 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.

Net Cash Provided by Operating Activities—Consists of the operating cash flow of all consolidated subsidiaries, including noncontrolling interests.

Year Ended December 31, 2012

Revenue increased $1.2 billion, or 7%, to $18.1 billion in 2012 compared with $16.9 billion in 2011. Key drivers of the increase included:

- the impact of new business of $1.9 billion including DPL, acquired in November 2011; Angamos, Maritza, Laurel Mountain and Changuinola, which commenced commercial operations in April, June, July and October of 2011, respectively, along with MountainView 4 which commenced operations in February 2012; and
- the unfavorable impact of foreign currency translation of $1.3 billion.

Excluding the impact of foreign currency and new businesses mentioned above, the SBU drivers included:

- US—Overall favorable impact of $121 million due to the temporary restart of two units at Southland in California, higher prices at IPL in Indiana and fewer outage days at Hawaii, slightly offset by lower volume at IPL due to milder weather.
- Andes—Overall unfavorable impact of $6 million due to lower exports from Termoandes in Argentina to Chile, lower prices in Argentina and the impact of outages in Argentina, almost entirely offset by higher volume in Chile and Argentina and higher prices in Colombia.
- Brazil—Overall favorable impact of $262 million due to higher tariffs to cover pass-through costs, higher contract and spot prices at Tietê and higher demand in the distribution companies partially offset by lower tariff at Eletropaulo due to the tariff reset.
- MCAC—Overall favorable impact of $216 million due to higher prices and volume from gas sales and higher ancillary services in the Dominican Republic, higher pass-through electricity costs in El Salvador and the favorable impact of Esti coming back into service, slightly offset by lower pass-through fuel costs at Merida in Mexico.
- EMEA—Overall unfavorable impact of $70 million due to the sale of 80% of our ownership in Cartagena in February 2012 and lower availability and reduced contract capacity prices in Ballylumford in Northern Ireland, partially offset by a non-recurring arbitration settlement at Cartagena, a mark-to-market loss on an embedded derivative at Sonel in Cameroon in 2011 that did not recur, higher volume and tariffs in the Ukraine and higher volume net of lower prices at Kilroot.
- Asia—Overall favorable impact of $121 million due to higher market demand and the reversal of a contingency at Masinloc in the Philippines and higher demand at Kelanitissa in Sri Lanka caused by lower hydrology and better plant reliability.

Gross margin decreased $349 million, or 9%, to $3.7 billion in 2012 compared with $4.1 billion in 2011. Key drivers of the decrease included:

- the unfavorable impact of foreign currency translation of $172 million; offset by
- the favorable impact of new business of $463 million, as discussed above.

Excluding the impact of foreign currency and new businesses on gross margin as mentioned above, the key SBU drivers included:

- US—Overall favorable impact of $67 million due to the temporary restart of two units at Southland, better availability at Hawaii, higher demand at DPL and higher prices at IPL slightly offset by lower volume at IPL.
- Andes—Overall unfavorable impact of $169 million due to lower prices in Chile, higher replacement energy cost in Chile and outages, outages in Argentina, and maintenance and higher fixed costs in Argentina and Chile partially offset by higher volume in Chile.

- Brazil—Overall unfavorable impact of $689 million due to lower tariffs as a result of the tariff reset of 2011 which was postponed to 2012 at Eletropaulo, for which we have a 16% economic ownership, and higher fixed costs at all businesses partially offset by higher volume and tariffs at Sul.
- MCAC—Overall unfavorable impact of $28 million due to lower volume in Panama and higher fixed costs in Puerto Rico partially offset by the impact of Esti returning to service.
- EMEA—Overall favorable impact of $128 million due to a non-recurring arbitration settlement at Cartagena, a mark-to-market loss on an embedded derivative at Sonel in 2011 that did not recur, higher volume offset by lower prices at Kilroot, higher volume and tariffs in the Ukraine and lower fixed costs at Sonel partially offset by the sale of 80% of our ownership in Cartagena.
- Asia—Overall favorable impact of $66 million due to higher market demand and the reversal of a contingency at Masinloc.

Net loss attributable to The AES Corporation was $912 million in 2012, which is a decrease of $1 billion compared to net income of $58 million in 2011. The key driver of the decrease was the goodwill impairment at DPL of $1.82 billion as described in Note 10—*Goodwill Impairment and Other Intangible Assets* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K.

Excluding the goodwill impairment at DPL, the Company would have reported net income attributable to AES of $905 million, which is an improvement of $847 million compared to 2011. The key drivers of this increase were:

- the favorable impact of gross margin earned by new businesses, mainly our wholly-owned subsidiaries: DPL, Maritza, and Changuinola, unfavorable impact in 2011 of an unrealized mark-to-market derivative at Sonel, which is a 56% owned subsidiary, higher demand at Masinloc, a 92% owned subsidiary, partially offset by a reduced gross margin at Eletropaulo, in which we hold only a 16% economic interest and a lower gross margin earned by our generation businesses in Chile and Argentina;
- the gains related to the sale in 2012 of 80% of our interest in Cartagena and the sale of our investments in China, as well as the loss recorded in 2011 on the sale of our Argentina distribution businesses;
- a decrease in losses from the operation of discontinued businesses, mainly related to Eastern Energy in New York, which was deconsolidated in December 2011;
- the decrease in asset impairments related to Wind projects and Kelanitissa;
- lower general and administrative expenses in 2012 compared to 2011; and
- the prior year premium paid on the early retirement of debt in Chile and at IPL.

These increases were partially offset by:

- higher foreign currency transaction losses in 2012 compared to 2011; and
- an increase in interest expense primarily due to debt at DPL, which was acquired in November 2011, and additional debt at the Parent Company to finance the acquisition of DPL.

Net cash provided by operating activities increased $17 million, or 1%, to $2.9 billion during 2012 compared to 2011, mainly due to the following:

- US—an increase of $320 million at our utility businesses primarily due to the operations, net of debt service costs, of DPL which was acquired in November 2011;
- Andes—an increase of $57 million driven by cash provided by the operating activities of the new plant at Angamos, recovery of value added tax at Campiche and reduced working capital requirements at Gener, partially offset by reduced gross margin from Gener operations other than Angamos;

- Brazil—a decrease of $503 million at our utility businesses primarily driven by higher priced energy purchases, regulatory charges and transmission costs payments, higher operating and maintenance expenses and lower accounts receivable collections due to the lower tariff starting in July 2012 at Eletropaulo, partially offset by a lower payment of income taxes;
- MCAC—an increase of $25 million at our generation businesses primarily due to the operations of the Esti plant being back on line from June 2012 and higher volumes of PPA sales at Panama and lower coal volume and price in 2012 at Itabo, partially offset by lower collections and lower sales in the Dominican Republic and higher taxes paid at Panama;
- EMEA—an increase of $42 million driven primarily by cash provided by the operating activities of the new plant at Maritza partially offset by a loss in revenue from a generator failure at Ballylumford in Northern Ireland; and
- Asia—an increase of $88 million driven primarily by Masinloc in the Philippines due to higher demand and reduced working capital requirements.

Year Ended December 31, 2011

Revenue increased $1.5 billion, or 10%, to $16.9 billion in 2011 compared with $15.4 billion in 2010. Key drivers of the increase included:

- the favorable impact of foreign currency of $460 million; and
- the impact of new businesses of $746 million including Ballylumford in Northern Ireland and DPL in the United States, acquired in August and late November 2011, respectively, and Angamos I, in Chile, and Maritza, in Bulgaria, and Angamos II, in Chile, that commenced operations in April, June and October 2011, respectively.

Excluding the impact of foreign currency and new businesses mentioned above, the SBU drivers included:

- US—Overall favorable impact of $3 million due to higher prices related to a fuel adjustment clause almost entirely offset by lower retail and wholesale volume at IPL.
- Andes—Overall favorable impact of $297 million due to higher prices in Argentina and Gener and higher volume at Chivor in Colombia, partially offset by lower prices in Chivor.
- Brazil—Overall unfavorable impact of $128 million due to lower prices at Eletropaulo primarily related to the estimated impact of the July 2011 tariff reset which was finalized by the Brazilian energy regulatory agency in July 2012, partially offset by higher demand at Eletropaulo.
- MCAC—Overall favorable impact of $270 million due to higher prices, volume and gas sales and higher ancillary services in the Dominican Republic, higher prices in Puerto Rico and higher pass-through electricity costs in El Salvador partially offset by outages in Panama.
- EMEA—Overall unfavorable impact of $157 million due to lower revenue from pass-through energy costs at Cartagena in Spain and by an unrealized mark-to-market derivative loss at Sonel in Cameroon partially offset by higher rates in the Ukraine and better plant availability at Ballylumford.
- Asia—Overall unfavorable impact of $12 million due to lower volume and price at Masinloc in the Phillipines almost entirely offset by higher rates and demand at Kelanitissa in Sri Lanka.

Gross margin increased $243 million, or 6%, to $4.1 billion in 2011 compared with $3.8 billion in 2010. Key drivers of the increase included:

- the favorable impact of foreign currency of $111 million; and
- new businesses of $197 million as discussed above.

Excluding the impact of foreign currency and new businesses on gross margin as mentioned above, the key SBU drivers included:

- US—Overall unfavorable impact of $41 million due to higher fuel costs at Shady Point in Oklahoma and Hawaii and lower wholesale margin and retail margin at IPL.
- Andes—Overall favorable impact of $175 million due to higher volume in Electrica Santiago at Gener in Chile.
- Brazil—Overall unfavorable impact of $11 million due to lower prices at Eletropaulo, as discussed above, offset by increased volume and lower fixed costs.
- MCAC—Overall favorable impact of $53 million due to higher volume and prices in the Dominican Republic as discussed above and higher volume in Panama partially offset by outages in Panama.
- EMEA—Overall unfavorable impact of $165 million due to an unrealized mark-to-market derivative loss at Sonel and lower volume and rates at Kilroot in Northern Ireland.
- Asia—Overall unfavorable impact of $71 million due to lower demand and prices and higher fuel and fixed costs at Masinloc.

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.

These increases were 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, mainly due to the following:

- US—a decrease of $131 million at our generation businesses primarily due to reduced operations in New York prior to its deconsolidation in December 2011, partially offset by the deconsolidation of Thames in 2011;
- Brazil—a decrease of $352 million at our utility businesses primarily driven by higher income tax payments of which $84 million was 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;
- Asia—a decrease of $56 million at Masinloc, due to lower gross margin.

Non-GAAP Measures

Adjusted pre-tax contribution ("adjusted PTC") and Adjusted earnings per Share ("adjusted EPS") are non-GAAP supplemental measures that are used by management and external users of our consolidated financial statements such as investors, industry analysts and lenders.

We define adjusted PTC as pre-tax income from continuing operations attributable to AES excluding gains or losses of the consolidated entity due to (a) unrealized gains or losses 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. Adjusted PTC also includes net equity in earnings of affiliates on an after-tax basis.

We define adjusted EPS as diluted earnings per share from continuing operations excluding gains or losses of the consolidated entity due to (a) unrealized gains or losses 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 PTC is income from continuing operations attributable to AES. The GAAP measure most comparable to adjusted EPS is diluted earnings per share from continuing operations. We believe that adjusted PTC and adjusted EPS better reflect the underlying business performance of the Company and are considered in the Company's internal evaluation of financial performance. Factors in this determination include the variability due to unrealized gains or losses related to derivative transactions, unrealized foreign 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. In addition, for adjusted PTC, earnings before tax represents the business performance of the Company before the application of statutory income tax rates and tax adjustments, including the effects of tax planning, corresponding to the various jurisdictions in which the Company operates. Adjusted PTC and adjusted EPS should not be construed as alternatives to income from continuing operations attributable to AES and diluted earnings per share from continuing operations, which are determined in accordance with GAAP.

The Company reported a loss from continuing operations of $1.21 per share in 2012. The Company did not have a loss from continuing operations in 2011 and 2010. For purposes of measuring diluted loss per share under GAAP, potential common stock was excluded from weighted average shares in 2012 as their inclusion would be anti-dilutive. However, for purposes of computing adjusted EPS, the Company has included the impact of potential common stock as the inclusion of the defined adjustments result in income for adjusted EPS. The table below reconciles the weighted average shares used in GAAP diluted loss per share to the weighted average shares used in calculating the non-GAAP measure of diluted loss per share, a component of the adjusted EPS calculation. The weighted average shares used in calculating the non-GAAP measure of diluted loss per share has also been used in calculating the per share impact of the adjusting items in the calculation of adjusted EPS.

Reconciliation of denominator used for Adjusted Earnings Per Share

	Year Ended December 31, 2012		
	Loss	**Shares**	**$ per Share**
GAAP DILUTED (LOSS) PER SHARE			
Loss from continuing operations attributable to The AES Corporation common stockholders	$(915)	755	$(1.21)
EFFECT OF DILUTIVE SECURITIES			
Convertible securities	—	—	—
Stock options	—	1	—
Restricted stock units	—	4	0.01
NON-GAAP DILUTED (LOSS) PER SHARE	$(915)	760	$(1.20)

	Year Ended December 31, 2012		Year Ended December 31, 2011		Year Ended December 31, 2010	
	Net of NCI*	Per Share (Diluted) Net of NCI and Tax	Net of NCI*	Per Share (Diluted) Net of NCI and Tax	Net of NCI*	Per Share (Diluted) Net of NCI and Tax
	(In millions, except per share amounts)					
Income (loss) from continuing operations attributable to AES and Diluted EPS	**$ (915)**	**$(1.20)**	**$ 492**	**$0.63**	**$496**	**$ 0.64**
Add back income tax expense from continuing operations attributable to AES	446		220		148	
Pre-tax contribution	$ (469)		$ 712		$644	
Adjustments						
Unrealized derivatives (gains)/ losses[(1)]	$ 118	$ 0.11	$ 11	$0.01	$ (2)	$ —
Unrealized foreign currency transaction (gains)/ losses[(2)]	(18)	(0.03)	38	0.05	(38)	(0.04)
Disposition/ acquisition (gains)	(206)	(0.18)[(3)]	—	—	—	— [(4)]
Impairment losses	1,936	2.53[(5)]	271	0.29[(6)]	322	0.28[(7)]
Debt retirement losses	16	0.01[(8)]	46	0.04[(9)]	29	0.03[(10)]
Adjusted pre-tax contribution and Adjusted EPS	**$1,377**	**$ 1.24**	**$1,078**	**$1.02**	**$955**	**$ 0.91**

* NCI is defined as noncontrolling interest

(1) Unrealized derivative (gains) losses were net of income tax per share of $0.04, $0.01 and $0.00 in 2012, 2011 and 2010, respectively.

(2) Unrealized foreign currency transaction (gains) losses were net of income tax per share of $0.00, $0.00 and ($0.01) in 2012, 2011 and 2010, respectively.

(3) Amount primarily relates to the gains from the sale of 80% of our interest in Cartagena for $178 million ($109 million, or $0.14 per share, net of income tax of $0.09 per share) and equity method investments in China of $24 million ($25 million, or $0.03 per share, including an income tax credit of $1 million, or $0.00 per share).

(4) The Company did not adjust 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 primarily relates to the goodwill impairment at DPL of $1.82 billion ($1.82 billion, or $2.39 per share, net of income tax of $0.00 per share). Amount also includes other-than-temporary impairment of equity method investments in China of $32 million ($32 million, or $0.04 per share, net of income tax of $0.00 per share), and at InnoVent of $17 million ($17 million, or $0.02 per share, net of income tax of $0.00 per share), as well as asset impairments of wind turbines and projects of $41 million ($26 million, or $0.03 per share, net of income tax of $0.02 per share), at Kelanitissa of $19 million ($17 million, or $0.02 per share, net of noncontrolling interest of $2 million and of income tax of $0.00 per share), and at St. Patrick of $11 million ($11 million, or $0.01 per share, net of income tax of $0.00 per share).

(6) Amount includes other-than-temporary impairment of equity method investments at Chigen, including Yangcheng, of $79 million ($79 million, or $0.10 per share, net of income tax of $0.00 per share), asset impairments of wind turbines of $116 million ($75 million, or $0.10 per share, net of income tax of $0.05 per share), Kelanitissa of $42 million ($38 million, or $0.05 per share, net of noncontrolling interest of $4 million and of income tax of $0.00 per share), Bohemia of $9 million ($9 million, and $0.01 per share, net of income tax of $0.00 per share), and goodwill impairment at Chigen of $17 million ($17 million or $0.02 per share, net of income tax of $0.00 per share).

(7) Amount primarily relates to asset impairments at Southland (Huntington Beach) of $200 million ($130 million, or $0.17 per share, net of income tax of $0.09 per share), at Deepwater of $79 million ($51 million, or $0.07 per share, net of income tax of $0.04 per share), and a goodwill impairment at Deepwater of $18 million ($18 million, or $0.02 per share, net of income tax of $0.00 per share).

(8) Amount primarily relates to the loss on retirement of debt at the Parent Company of $15 million ($10 million, or $0.01 per share, net of income tax of $0.01 per share).

(9) Amount includes loss on retirement of debt at Gener of $38 million ($22 million, or $0.03 per share, net of noncontrolling interest of $11 million and of income tax of $0.01 per share) and at IPL of $15 million ($10 million, or $0.01 per share, net of income tax of $0.01 per share).

(10) Amount includes loss on retirement of debt at the Parent Company of $15 million ($10 million, or $0.01 per share, net of income tax per share of $0.01), at Andres of $10 million ($10 million, or $0.01 per share, net of income tax per share of $0.00) and at Itabo of $8 million ($4 million, or $0.01 per share, net of noncontrolling interest of $4 million and income tax of $0.00 per share).

Consolidated Results of Operations

Results of operations	Year Ended December 31, 2012	2011	2010	$ change 2012 vs. 2011	$ change 2011 vs. 2010
	(in millions, except per share amounts)				
Revenue:					
US—Generation	$ 861	$ 784	$ 806	$ 77	$ (22)
US—Utilities	2,898	1,326	1,145	1,572	181
Andes—Generation	3,020	2,989	2,519	31	470
Brazil—Generation	1,087	1,128	1,031	(41)	97
Brazil—Utilities	5,720	6,621	6,340	(901)	281
MCAC—Generation	1,723	1,575	1,400	148	175
EMEA—Generation	1,376	1,501	1,208	(125)	293
Asia—Generation	738	626	618	112	8
Corporate and Other(1)	1,809	1,565	1,435	244	130
Intersegment Eliminations(2)	(1,091)	(1,192)	(1,059)	101	(133)
Total Revenue	$18,141	$16,923	$15,443	$ 1,218	$1,480
Gross Margin:					
US—Generation	$ 237	$ 200	$ 205	$ 37	$ (5)
US—Utilities	483	220	250	263	(30)
Andes—Generation	580	743	519	(163)	224
Brazil—Generation	735	815	743	(80)	72
Brazil—Utilities	234	988	968	(754)	20
MCAC—Generation	504	464	406	40	58
EMEA—Generation	538	426	325	112	101
Asia—Generation	250	178	241	72	(63)
Corporate and Other(3)	118	7	144	111	(137)
Intersegment Eliminations(2)	35	22	19	13	3
General and administrative expenses	(301)	(391)	(391)	90	—
Interest expense	(1,572)	(1,553)	(1,449)	(19)	(104)
Interest income	349	399	407	(50)	(8)
Other expense	(93)	(153)	(232)	60	79
Other income	105	149	100	(44)	49
Gain on sale of investments	219	8	—	211	8
Goodwill impairment	(1,817)	(17)	(21)	(1,800)	4
Asset impairment expense	(73)	(173)	(304)	100	131
Foreign currency transaction losses	(167)	(39)	(33)	(128)	(6)
Other non-operating expense	(50)	(82)	(7)	32	(75)
Income tax expense	(708)	(634)	(593)	(74)	(41)
Net equity in earnings (losses) of affiliates	34	(2)	184	36	(186)
Income (loss) from continuing operations	(360)	1,575	1,481	(1,935)	94
Loss from operations of discontinued businesses	(13)	(131)	(486)	118	355
Gain from disposal of discontinued businesses	16	86	64	(70)	22
Net income (loss)	(357)	1,530	1,059	(1,887)	471
Noncontrolling interests:					
Income from continuing operations attributable to noncontrolling interests	(555)	(1,083)	(985)	528	(98)
Income from discontinued operations attributable to noncontrolling interests	—	(389)	(65)	389	(324)
Net income (loss) attributable to The AES Corporation	$ (912)	$ 58	$ 9	$ (970)	$ 49
AMOUNTS ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS:					
Income (loss) from continuing operations, net of tax	$ (915)	$ 492	$ 496	$(1,407)	$ (4)
Income (loss) from discontinued operations, net of tax	3	(434)	(487)	437	53
Net income (loss)	$ (912)	$ 58	$ 9	$ (970)	$ 49

(1) Corporate and Other includes revenue from our utility businesses in El Salvador, Africa and Europe.
(2) Represents inter-segment eliminations primarily related to transfers of electricity from Tietê (Brazil—Generation) to Eletropaulo (Brazil—Utilities).
(3) Corporate and Other gross margin includes gross margin from our utility businesses in El Salvador, Africa and Europe.

Key Trends and Uncertainties

For key trends and uncertainties, see Item 1.—Business and Item 1A.—*Risk Factors* of this Form 10-K. Some of these factors are also described below. However, management expects that improved operating performance at certain businesses, growth from new business and global cost reduction initiatives may lessen or offset the impact of the challenges described below. If these favorable effects do not occur, or if the challenges described below and elsewhere in this section impact us more significantly than we currently anticipate, or if volatile foreign currencies and commodities move more 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. We continue to monitor our operations and address challenges as they arise.

In 2013, we expect to face continued challenges at certain of our businesses:

On-going Regulatory Proceedings

Some of our utility companies, including DPL in the United States and AES Sul in Brazil, are in the process of their regulated tariff review and/or reset by the applicable regulatory agency. The tariff outcome will determine the amount that our utility companies can charge to customers for electricity.

On October 5, 2012, DPL filed an ESP with the PUCO to establish SSO rates that were to be in effect starting January 1, 2013. The plan requested approval of a non-bypassable charge that is designed to recover $138 million per year for five years from all customers. DPL also requested approval of a switching tracker that would measure the incremental amount of switching over a base case and defer the lost value into a regulatory asset which would be recovered from all customers beginning January 2014. The ESP states that DPL plans to file on or before December 31, 2013 its plan for legal separation of its generation assets. The ESP proposes a three year and five month transition to market, whereby a wholesale competitive bidding structure will be phased in to supply generation service to SSO customers. The PUCO is currently reviewing the filing and an evidentiary hearing is scheduled to begin on March 11, 2013. The PUCO authorized that the rates being collected prior to December 31, 2012 would continue until the new ESP rates go into effect. See Item 1.—*Business—United States SBU, DPL* included in this Form 10-K for further information. In addition to the regulatory risks noted above, DPL also faces a number of additional uncertainties related to the impact of customer switching and low power prices which could impact DPL's results of operations, its ability to refinance certain debt (or to do so on favorable terms) which is due in the near to intermediate term, and/or realize the benefits associated with the remaining goodwill. Any of the above-referenced conditions, events or factors could have a material impact on the Company or its results of operations.

AES Sul in Brazil is currently undergoing the tariff reset process. A public hearing has started and will be concluded in March 2013, with the revised tariff to be implemented in April 2013.

Macroeconomic and Political Conditions

The Company is sensitive to changes in economic and political conditions, including foreign exchange rates. In Argentina and the Dominican Republic, the potential weakening of economic indicators, such as increased inflation, devaluation of the local currency, currency convertibility restrictions and large government deficits could have a material impact on the Company. Potential outcomes can include negative impacts in our gross margin and cash flows, and create an inability of the business to pay dividends or obtain currency to service foreign obligations, all of which can negatively impact the value of our assets. See Item 7A—*Quantitative and Qualitative Disclosures about Market Risk* of this Form 10-K for more information.

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, 2012, 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.

Fluctuations in Commodity Prices

The Company is sensitive to changes in natural gas prices. High coal prices relative to natural gas creates pressure at our U.S. businesses, which may affect the results of certain of our coal plants, 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. See Item 7A.—*Quantitative and Qualitative Disclosures About Market Risk* of this Form 10-K for more information.

Global diversification helps us mitigate certain risks. 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.

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, several European Union countries continue to face uncertain economic environments, 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.

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 remains 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. We have not suffered any material effects related to our counterparties during the year ended December 31, 2012. 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.

United States—As noted in 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 and Item 7A.—*Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk* of this Form 10-K, the Company's U. S. businesses continue to face pressure as a result of low natural gas prices, the marginal price setting fuel in most U. S. markets. This has affected the results of certain of our coal-fired plants in the region, including our coal-fired generating assets within our utility businesses, like IPL, which benefit from high wholesale power prices in periods where our available generation exceeds our captive load obligations. At DPL, where retail competition exists, our coal-fired generating assets do not benefit from the captive load offset and, as such, are subject to greater sensitivity to changes in power prices. Businesses that have a PPA in place, but purchase fuel at market prices or under short term contracts may not be fully hedged against changes in either power or fuel prices.

On December 27, 2012, the U.S. Bankruptcy Court for the District of Delaware issued its Order Confirming the Second Amended Joint Plan of Liquidation under Chapter 11 of the Bankruptcy Code filed by AES Eastern Energy, L.P. and certain affiliates that owned coal-fired plants in New York and had filed for bankruptcy in 2011. In accordance with its terms, the Plan became effective on December 28, 2012. An integral component of the Plan was the settlement between the Company, the Debtors and the Official Committee of Unsecured Creditors. Pursuant to that settlement, the Debtors and the Committee have released the Company and its non-debtor affiliates from claims and causes of action they have or may have in the future. In exchange, the Company paid $47 million to and waived all unpaid claims against the Debtors. In addition, the Company assumed a net pension liability of $25 million for employees of AES NY, L.L.C.

Argentina—In Argentina, the deterioration of certain economic indicators such as non-receding inflation, increased government deficits and foreign currency accessibility combined with the potential devaluation of the local currency and the potential fall in export commodity prices could cause significant volatility in our results of operations, cash flows, the ability to pay dividends to corporate, and the value of our assets. At December 31, 2012, AES had noncurrent assets of $564 million in Argentina, including long-term receivables of $316 million. In addition, recent actions by the Argentine government may indicate deeper government intervention in the local economy. For example, on April 16, 2012, the Argentine government expropriated 51% of the assets of the country's largest oil company. The statute used to expropriate the oil company is not applicable to our businesses in Argentina. However, potential deteriorating economic conditions or further government action could have a material impact on the Company or its financial statements.

Brazil—Given that approximately two-thirds of Brazil's electric supply is dependent upon hydroelectric generation, changes in weather conditions can have a significant impact on reservoir levels and electricity prices.

The hot, dry summer has cause the reservoir levels to be lower than they have been in a number of years. If reservoir levels are not able to recover, or deteriorate further, it is expected that higher thermal dispatch will cause more volatility in spot prices. Although the purchased energy cost is a pass-through for AES' distribution businesses in Brazil, gaps between the purchase of energy and recovery in the tariff could cause temporary cash flow constraints on those businesses. Also, to the extent that the hydroelectric facility would need to purchase energy to meet its contract needs, rather than generate the energy, it could have a material adverse impact on our results of operations.

Bulgaria—Our investments in Bulgaria rely on offtaker contracts with NEK, the state-owned national electricity distribution company. Maritza, a coal-fired generation facility, has experienced on-going delays in collections from their offtaker, although they were able to collect $73 million of past due receivables in the fourth quarter of 2012 from NEK, which brought down the outstanding receivables balance to $55 million as of December 31, 2012. There can be no assurance that the business will succeed in making these collections, which could result in a write-off of the receivables. In addition, depending on NEK's ability to honor its obligations and other factors, the value of other assets could also be impaired, or the business may be in default of its loan covenants. The Company has long-lived assets in Bulgaria of $1.8 billion. Any of the above items could have a material impact on our results of operations. 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 face a loss of earnings and/or cash flows from the affected businesses and 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.

Euro Zone—During the past few years, 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. 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 and could result in losses or asset impairments for these businesses which could be material. The carrying value of our investment in AES Solar Energy Ltd., whose primary operations are in Europe, was $130 million at December 31, 2012. 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.

If global economic conditions deteriorate further, 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 pursuant to PPAs, concession agreements or other contracts as they 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

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 factor 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. Another factor relates to the market or commodity dynamics, which can change after the acquisition. For example, DPL recognized a goodwill impairment of $1.82 billion during 2012. See Note 10—*Goodwill and Other Intangible Assets* included in Item 1.— *Financial Statements and Supplementary Data* of this Form 10-K for further information.

The value of goodwill is also positively correlated with the economic environments in which our acquired businesses operate. Also, the evolving environmental regulations, including GHG regulations, around the world continue to increase the operating costs of our generation businesses. In extreme situations, 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. For example, Ebute, our 294 MW gas-fired plant in Nigeria, currently operates under a 15 year PPA with the Nigerian national electricity distribution company that expires within the next few years. The inability to replace the PPA on similar terms or identify alternate uses for the plant could adversely affect the carrying amount of Ebute's goodwill, which could be material. In our calculation of the fair value of the Ebute reporting unit, we have considered a market participant view that assumes significant expansion of the generation facility, which may be uncertain and is dependent upon regulatory approvals and financing availability, among other uncertainties. The carrying amount of the goodwill at December 31, 2012 was approximately $58 million.

In the fourth quarter of 2012, the Company completed its annual October 1 goodwill impairment evaluation and identified two reporting units, DPL and Ebute, 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 during the fourth quarter of 2012 related to DPL and Ebute that could result in the recognition of goodwill impairment, it is possible that we may incur goodwill impairment at any of our reporting units in future periods if adverse changes in their business or operating environments occur. The carrying amount of the goodwill at DPL and Ebute as of December 31, 2012 was approximately $759 million and $58 million, respectively.

Long-lived assets—The global economic conditions and other adverse factors discussed above heighten the risk of significant asset impairment. The Company continually evaluates the impact of any adverse changes in operating and business environments on the fair value of its long-lived assets.

Wind turbines—During the third quarter of 2012, the Company recognized an impairment expense of $20 million related to certain wind turbines held in storage. The Company determined that these turbines met the held-for-sale criteria due to the ongoing receipt of offers from potential buyers and less viable internal deployment scenarios. The turbines with a carrying amount of $45 million were written down to their estimated fair value (less costs to sell) of $25 million. As of December 31, 2012 the Company concluded the turbines should continue to be classified as held for sale and no adjustment to the carrying amount is required. It is reasonably possible that the turbines could incur further loss in value due to changing market conditions, regulatory environment and advances in technology. Refer to Note 21—*Asset Impairment Expense* included in Item 1.—Financial Statements and Supplementary Data of this Form 10-K for further information

Revenue and Gross Margin Analysis

US SBU

US—Generation

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

	For the Years Ended December 31,				
	2012	2011	2010	% Change 2012 vs. 2011	% Change 2011 vs. 2010
	($'s in millions)				
US Generation					
Revenue	$861	$784	$806	10%	-3%
Gross Margin	$237	$200	$205	19%	-2%

Fiscal Year 2012 versus 2011

Generation revenue for 2012 increased $77 million, or 10%, from 2011 primarily due to:

- an increase of $28 million at Southland in California, primarily due to the short-term restart of two generating units at the Huntington Beach which were contracted through October 2012;
- the impact of new business of $25 million from Mountain View IV in California and Laurel Mountain in West Virginia, which began operations in February of 2012 and July of 2011, respectively;
- an increase of $13 million in Hawaii and $7 million at Beaver Valley in Pennsylvania, primarily due to higher volumes as a result of fewer outage days; and
- $7 million higher revenue at Deepwater in Texas, primarily due to the sale of NOx allowances.

Generation gross margin for 2012 increased $37 million, or 19%, from 2011 primarily due to:

- an increase of $21 million at Southland, primarily due to the short-term restart of two generating units at Huntington Beach;
- an increase of $20 million in Hawaii, primarily due to higher volumes as a result of fewer outage days and lower fixed costs; and
- the impact of new business of $4 million from Mountain View IV and Laurel Mountain, which began operations in February of 2012 and July of 2011, respectively

For the year ended December 31, 2012, revenue increased 10% while gross margin increased 19%, primarily due to higher volumes and the short-term restart of two generating units at Huntington Beach that had a positive impact on gross margin and a decrease in fixed costs.

Fiscal Year 2011 versus 2010

Generation revenue for 2011 decreased $22 million, or 3%, from 2010 primarily due to:

- 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.

Generation gross margin for 2011 decreased $5 million, or 2%, from 2010 primarily due to:

- higher fuel costs and lower volume at Hawaii of $11 million;
- higher fuel costs at Shady Point in Oklahoma of $10 million; and

- a decrease in volume of $6 million at Deepwater as discussed above.

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; and
- lower fixed costs at Deepwater of $10 million.

US—Utilities

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

	For the Years Ended December 31,				
	2012	2011	2010	% Change 2012 vs. 2011	% Change 2011 vs. 2010
	($'s in millions)				
US Utilities					
Revenue	$2,898	$1,326	$1,145	119%	16%
Gross Margin	$ 483	$ 220	$ 250	120%	-12%

Fiscal Year 2012 versus 2011

Utilities revenue for 2012 increased $1.6 billion, or 119%, from 2011 primarily due to:

- the impact of new business of $1.5 billion from the operations of DPL, in Ohio, which was acquired in November 2011;
- higher prices of $68 million at IPL in Indiana, primarily due to higher fuel adjustment and other pass-through charges; and
- higher volume of $27 million at DPL in December 2012, primarily due to increased energy available for wholesale sales caused by switching of regulated customers to other suppliers as well as new retail customers added in the Illinois service territory which are served with power purchased by DPL.

These increases were partially offset by:

- lower prices of $24 million at DPL in December 2012, primarily due to lower capacity revenue and lower average retail prices due to downward price pressure as a result of generation services competition which we expect to continue in 2013 given the cleared auction prices for capacity; and
- lower volume of $16 million at IPL, primarily due to warmer winter weather in 2012 and because IPL's generating units are being priced out of market more often in 2012, reducing wholesale sales opportunities.

Utilities gross margin for 2012 increased $263 million, or 120%, from 2011 primarily due to:

- the impact of new business of $222 million from DPL, in Ohio, in 2012 which was acquired in November 2011;
- higher margin of $42 million in December 2012, primarily due to increases in wholesale margins due to increased volumes as described above and reductions in fixed operating costs primarily related to the acquisition of DPL by AES; and
- lower repairs and maintenance costs at IPL of $21 million, primarily due to fewer generating unit outages.

These increases were partially offset by:

- lower rates of $10 million primarily due to DP&L customers switching to DPL Inc.'s competitive retail supplier; and
- higher pension expenses of $5 million at IPL, primarily due to a decrease in the estimated pension obligations at December 31, 2011.

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, 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.

These increases were partially offset by:

- lower retail volume of $21 million, primarily due to unfavorable weather and economic conditions at IPL; and
- lower wholesale volume of $16 million at IPL, primarily due to increased generating unit outages.

Utilities gross margin for 2011 decreased $30 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 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.

Andes SBU

Andes—Generation

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

	For the Years Ended December 31,				
	2012	2011	2010	% Change 2012 vs. 2011	% Change 2011 vs. 2010
	($'s in millions)				
Andes Generation					
Revenue	$3,020	$2,989	$2,519	1%	19%
Gross Margin	$ 580	$ 743	$ 519	-22%	43%

Fiscal Year 2012 versus 2011

Excluding the unfavorable impact of foreign currency translation of $66 million, generation revenue for 2012 increased $97 million, compared to 2011 primarily due to:

- new business impact of $106 million at Angamos in Chile, which commenced operations in 2011,
- higher spot and contract prices of $75 million at Chivor in Colombia due to pressure on prices from lower water inflows caused by El Nino; and
- higher contract levels and lower energy prices of $25 million at Gener in Chile.

These increases were offset by:

- The adverse impact of $57 million on prices in Argentina as a result of higher generation using natural gas and a price adjustment agreement executed in 2011; and
- negative impact of $55 million in Argentina as a result of outages at our San Nicolas and Parana plants.

Excluding the unfavorable impact of foreign currency translation of $4 million, generation gross margin for 2012 decreased $159 million, or 21%, from 2011 primarily due to:

- negative impact of $109 million due to lower exports from Termoandes in Argentina to Chile, higher cost of replacement energy and higher gas prices in Chile,
- higher fixed and operating costs of $45 million across the region , primarily attributable to higher maintenance costs and employee costs offset by $11 million from a non-recurring equity tax in Chivor in 2011; and
- lower prices in Argentina of $28 million as a result of a price adjustment agreement executed in 2011.

These decreases were partially offset by:

- new business impact of $11 million at Angamos in Chile, which commenced operations in 2011

For the year ended December 31, 2012, revenue increased by 1% while gross margin decreased 22%, primarily due to the impact of purchasing replacement energy and higher maintenance and employee costs.

Fiscal Year 2011 versus 2010

Excluding the unfavorable impact of foreign currency translation of $37 million, generation revenue for 2011 increased $507 million, or 20%, 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;
- 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; and
- higher volume of $91 million in Colombia due to higher water inflows in the system during 2011.

These increases were partially offset by:

- lower spot prices of $128 million in Colombia due to higher water inflows in the system during 2011.

Excluding the unfavorable impact of foreign currency translation of $2 million, generation gross margin for 2011 increased $226 million, or 44%, 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;
- new business of $51 million at Angamos; 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; and
- higher fixed and operating costs of $31 million in Argentina, primarily attributable to higher employee costs, maintenance costs, an increase in non-income taxes.

For the year ended December 31, 2011, revenue increased by 19% while gross margin increased 43%, primarily due to lower energy purchases at Gener due to higher generation.

Brazil SBU

Brazil—Generation

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

	For the Years Ended December 31,				
	2012	2011	2010	% Change 2012 vs. 2011	% Change 2011 vs. 2010
	($'s in millions)				
Brazil Generation					
Revenue	$1,087	$1,128	$1,031	-4%	9%
Gross Margin	$ 735	$ 815	$ 743	-10%	10%

Fiscal Year 2012 versus 2011

Excluding the unfavorable impact of foreign currency translation of $181 million, generation revenue for 2012 increased $140 million, or 12%, from 2011 at Tietê primarily due to:

- higher contract prices of $77 million as a result of PPA annual indexation in July each year;
- $51 million of higher spot prices as a result of increase in demand and lower water inflows in the system; and
- higher volume of $12 million due to higher demand in the market.

Excluding the unfavorable impact of foreign currency translation of $124 million, generation gross margin for 2012 increased $44 million, or 5%, from 2011 at Tietê primarily due to:

- higher prices of $72 million, as discussed above;

These increases were partially offset by:

- higher fixed and operating costs of $27 million primarily attributable to higher maintenance costs, transmission charges and employee costs.

For the year ended December 31, 2012, revenue decreased 4% while gross margin decreased 10%, primarily due to higher fixed costs partially offset by higher spot and contract prices at Tietê.

Fiscal Year 2011 versus 2010

Excluding the favorable impact of foreign currency translation of $51 million, generation revenue for 2011 increased $46 million, or 4%, from 2010 primarily due to:

- higher contract prices of $45 million at Tietê as a result of PPA annual indexation in July each year; and
- higher volume of $35 million due to higher demand at Tietê by the offtakers.

These increases were partially offset by:

- 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.

Excluding the favorable impact of foreign currency translation of $36 million, generation gross margin for 2011 increased $36 million, or 5%, from 2010 primarily due to:

- higher contract prices and volume of $72 million at Tietê, as discussed above; and
- lower cost of energy purchases of $12 million at Tietê.

These increases were partially offset by:

- a decrease of $32 million related to the final settlement of the power sales agreement between Uruguaiana and Sul as discussed above; and
- higher depreciation of $16 million 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.

Brazil—Utilities

The following table summarizes revenue and gross margin for our Brazil Utilities segment which includes Sul which is 100% owned and Eletropaulo which has an economic ownership of 16% for the periods indicated:

	For the Years Ended December 31,				
	2012	2011	2010	% Change 2012 vs. 2011	% Change 2011 vs. 2010
	($'s in millions)				
Brazil Utilities					
Revenue	$5,720	$6,621	$6,340	-14%	4%
Gross Margin	$ 234	$ 988	$ 968	-76%	2%

Fiscal Year 2012 versus 2011

Excluding the unfavorable impact of foreign currency translation of $934 million, utilities revenue for 2012 increased $33 million compared to 2011 primarily due to:

- higher tariffs of $130 million at Sul due to the April 2012 annual adjustment that increased the tariff by 12% to cover energy and transmission costs, regulatory charges, taxes and operations and maintenance; and
- higher volume of $98 million due to increased market demand across the segment.

These increases were partially offset by:

- lower tariffs of $104 million at Eletropaulo mainly driven by:
- decrease of $446 million as a result of the July 2011 tariff reset passed by the Brazilian energy regulator in July 2012;

- decrease of $111 million starting in July 2012 compared to the tariff charged in 2011; partially offset by
- increase of $453 million due to the annual adjustment to cover energy and transmission pass through costs.
- reduction in other revenue related to reactive energy and excess energy demand revenue by $60 million, that are now recorded as special obligations as a result of a change in the regulation; and
- lower transmission revenue and other adjustments of $35 million at Eletropaulo.

Excluding the unfavorable impact of foreign currency translation of $22 million, utilities gross margin for 2012 decreased $732 million, or 74%, from 2011 primarily due to:

- lower tariffs of $550 million at Eletropaulo mainly driven by:
- decrease of $439 million as a result of the July 2011 tariff reset passed by the Brazilian energy regulator in July 2012; and
- decrease of $111 million starting in July 2012 compared to the tariff charged in 2011
- reduction in other revenue related to reactive energy and excess energy demand revenue by $60 million, that are now recorded as special obligations as a result of a change in the regulation; and
- lower transmission revenue and other adjustments of $30 million at Eletropaulo.
- higher fixed costs of $218 million at Eletropaulo mainly driven by:
- higher employee costs resulting from a collective wage agreement and higher pension expense of $100 million;
- higher contingencies (mainly labor) of $41 million;
- higher bad debt expense of $33 million;
- VAT over commercial losses reversal recorded in 2011 of $22 million; and
- An increase in maintenance and other expense of $22 million.

These decreases were partially offset by:

- higher volume of $86 million due to increased market demand partially offset by higher spot market purchases at Sul; and
- higher tariffs of $33 million at Sul due to the annual adjustment described above.

For the year ended December 31, 2012, revenue decreased 14% while gross margin decreased 76%, primarily due to higher fixed costs at Eletropaulo and pass-through revenue at Eletropaulo and Sul which helped offset the revenue decline but had no corresponding impact on gross margin.

Fiscal Year 2011 versus 2010

Excluding the favorable impact of foreign currency translation of $362 million, utilities revenue for 2011 decreased $81 million, or 1% from 2010 primarily due to:

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

These decreases were partially offset by:

- higher volume of $266 million due to increased market demand; and
- higher tariffs of $27 million at Sul due to higher volume of energy purchases which are passed through to customers.

Excluding the favorable impact of foreign currency translation of $63 million, utilities gross margin for 2011 decreased $43 million, or 4%, from 2010 primarily due to:

- lower tariffs of $207 million, primarily related to the estimated impact of the July 2011 tariff reset at Eletropaulo as discussed above;
- higher depreciation of $49 million 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 due to increased market demand;
- lower fixed costs of $71 million primarily due to contingency reversals and a non-recurring reduction in bad debt expense; and
- a decrease of $32 million related to the final settlement of the power sales agreement between Sul and Uruguaiana in the second quarter of 2010.

MCAC SBU

MCAC—Generation

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

	For the Years Ended December 31,				
	2012	2011	2010	% Change 2012 vs. 2011	% Change 2011 vs. 2010
	($'s in millions)				
MCAC Generation					
Revenue	$1,723	$1,575	$1,400	9%	13%
Gross Margin	$ 504	$ 464	$ 406	9%	14%

Fiscal Year 2012 versus 2011

Excluding the unfavorable impact of foreign currency translation of $17 million, generation revenue for 2012 increased $165 million, or 10%, from 2011 primarily due to:

- the positive impact of $126 million at Andres-Los Mina in the Dominican Republic mainly from higher international gas prices and volume of gas sales to third parties and ancillary services;
- new business of $50 million at Changuinola in Panama, which commenced operations in 2011;
- increase of $40 million at Panama mainly due to the Esti plant being back on-line from June 2012 as well as higher volume of PPA sales;
- an increase of $23 million at Merida in Mexico, primarily due to higher volume; and
- an increase at TEG/TEP in Mexico, of $18 million, primarily due to higher availability bonuses and higher rates.

These increases were partially offset by:

- decrease of $42 million at Andres-Los Mina due to lower volume and lower PPA prices mainly driven by price indexation due to a decrease in NYMEX gas prices;
- lower pass-through rates of $31 million at Merida due to lower fuel costs;
- a decrease of $15 million in Puerto Rico, primarily due to lower availability resulting from higher forced outages; and
- a decrease of $15 million at Changuinola mainly due to lower rates and PPA prices.

Excluding the unfavorable impact of foreign currency translation of $2 million, generation gross margin for 2012 increased $42 million, or 9%, from 2011 primarily due to:

- new business of $101 million at Changuinola as described above;
- the positive impact of $41 million at Andres-Los Mina of higher gas sales and ancillary services as discussed above;
- higher contract prices of $25 million at Itabo in the Dominican Republic, primarily related to lower fuel costs; and
- the positive impact of $17 million due to the Esti plant as described above.

These increases were partially offset by:

- a decrease in Panama of $72 million primarily related to higher energy purchases;
- lower volume and PPA prices of $44 million at Andres-Los Mina as described above;
- a decrease of $17 million in Puerto Rico primarily due to lower availability and higher fixed costs as a result of higher forced outages; and
- a decrease of $9 million at Merida due to higher outages and lower rates as described above.

Fiscal Year 2011 versus 2010

Excluding the favorable impact of foreign currency translation of $9 million, generation revenue for 2011 increased $166 million, or 12%, from 2010 primarily due to:

- higher ancillary services and third party gas sales of $57 million and $21 million higher volume at Andres-Los Mina;
- higher contract prices of $53 million at Itabo primarily from PPAs indexed to coal;
- 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;
- higher volume of $22 million in Panama due to higher water inflows in the system during 2011; and
- higher volume of $8 million at TEG/TEP.

These increases were partially offset by the following:

- a net decrease of $19 million related to the forced outage in Panama; and
- decreases at Merida 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 increased $58 million, or 14%, from 2010 primarily due to:

- higher ancillary services and gas sales of $36 million and higher energy prices of $27 million at Andres-Los Mina;
- higher volume of $40 million in Panama as a result of higher water inflows in the system during 2011; and
- an increase in Puerto Rico of $9 million primarily due to a prior year forced outage and the related penalty.

These increases were partially offset by:

- a decrease of $39 million related to higher spot purchases and the forced outage in Panama; and
- a decrease of $17 million at TEG/TEP and Merida due to a combination of forced and scheduled outages and higher fuel costs.

EMEA SBU

EMEA—Generation

The following table summarizes revenue and gross margin for our EMEA generation segment for the periods indicated:

	For the Years Ended December 31,				
	2012	2011	2010	% Change 2012 vs. 2011	% Change 2011 vs. 2010
			($'s in millions)		
EMEA Generation					
Revenue	$1,376	$1,501	$1,208	-8%	24%
Gross Margin	$ 538	$ 426	$ 325	26%	31%

Fiscal Year 2012 versus 2011

Excluding the unfavorable impact of foreign currency translation of $41 million, generation revenue for 2012 decreased $84 million, or 6%, from 2011 primarily due to:

- a decrease of $233 million as a result of the sale of 80% of our ownership of Cartagena, in Spain, in February 2012;
- a decrease of $136 million at Ballylumford in Northern Ireland, due to higher forced and planned outages, lower pass through costs included in revenue as a result of lower dispatch and lower capacity prices in the PPA; and
- a decrease of $25 million as a result of the sale of Bohemia, in the Czech Republic, in September 2011.

These decreases were partially offset by:

- new business contribution of $174 million from Maritza, in Bulgaria, which commenced commercial operations in June 2011;
- a non-recurring favorable arbitration settlement at Cartagena of $95 million; and
- an increase of $47 million at Kilroot, in Northern Ireland, primarily due to increased dispatch of the plant.

Excluding the unfavorable impact of foreign currency translation of $22 million, generation gross margin for 2012 increased $134 million, or 31%, from 2011 primarily due to:

- the new business impact of $117 million at Maritza, as discussed above;

- a non-recurring favorable arbitration settlement at Cartagena of $95 million; and
- an increase of $35 million at Kilroot, as discussed above.

These increases were partially offset by:

- a decrease of $68 million from Cartagena as a result of the sale of 80% of our ownership in February 2012;
- a decrease of $48 million at Ballylumford, as discussed above and also due to higher fixed costs and depreciation;
- a decrease of $8 million in Kazakhstan primarily due to higher fixed costs; and
- a decrease of $6 million as a result of the sale of Bohemia, in the Czech Republic, in September 2011.

For the year ended December 31, 2012, revenue decreased 8% primarily due to the sale of 80% of our ownership in Cartagena while gross margin increased 26% primarily due to favorable arbitration settlement at Cartagena.

Fiscal Year 2011 versus 2010

Excluding the favorable impact of foreign currency translation of $41 million, generation revenue for 2011 increased $252 million, or 21%, from 2010 primarily due to:

- the favorable impact of $256 million from the operations at Ballylumford, 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:

- a decrease of $160 million at Cartagena primarily due to lower pass-through energy costs;
- a decrease 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 $11 million, generation gross margin for 2011 increased $90 million, or 28%, from 2010 primarily due to:

- the favorable impact of $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
- the new business impact of $66 million at Maritza, which commenced operations in June 2011.

These increases were partially offset by:

- a decrease 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 CO_2 costs passed through in the market price in 2011.

Asia SBU

Asia—Generation

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

	For the Years Ended December 31,				
	2012	2011	2010	% Change 2012 vs. 2011	% Change 2011 vs. 2010
	($'s in millions)				
Asia Generation					
Revenue	$738	$626	$618	18%	1%
Gross Margin	$250	$178	$241	40%	-26%

Fiscal Year 2012 versus 2011

Excluding the unfavorable impact of foreign currency translation of $9 million, generation revenue for 2012 increased $121 million, or 19%, from 2011 primarily due to:

- an increase at Masinloc in the Philippines of $64 million primarily driven by:
- the $36 million favorable impact of higher market demand, partially offset by lower rates;
- the reversal of a contingency of $16 million; and
- the $13 million favorable impact of a mark-to-market adjustment on an inflation-related embedded derivative.
- an increase of $51 million at Kelanitissa in Sri Lanka primarily attributable to higher offtaker demand as a result of lower hydrology, and higher fuel pass-through revenue, as well as better plant reliability.

Excluding the favorable impact of foreign currency translation of $6 million, primarily in the Philippines, generation gross margin for 2012 increased $66 million, or 37%, from 2011 primarily due to the following:

- an increase at Masinloc in the Philippines of $66 million primarily driven by:
- the $35 million favorable impact of higher market demand, partially offset by lower rates;
- the reversal of a contingency of $16 million; and
- the $13 million favorable impact of a mark-to-market adjustment on an inflation-related embedded derivative.

These increases were partially offset by:

- higher fixed costs of $7 million related to commitment fees on undrawn construction loans at Mong Duong II in Vietnam.

For the year ended December 31, 2012, revenue increased 18% while gross margin increased 40%. This was primarily due to the impact of higher spot market margins at Masinloc and a gain on a mark-to-market inflation-related embedded derivative and reversal of a contingency. We expect gross margin in 2013 to be reduced due to a step down in the PPA at Masinloc

Fiscal Year 2011 versus 2010

Excluding the favorable impact of foreign currency translation of $20 million, generation revenue for 2011 decreased $12 million, or 2%, from 2010 primarily due to:

- a decrease of $39 million at Masinloc 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 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 $71 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.

Corporate and Other

Corporate and other includes the net operating results from our utility businesses in El Salvador, Africa and Europe, 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,				
	2012	2011	2010	% Change 2012 vs. 2011	% Change 2011 vs. 2010
	($'s in millions)				
Revenue					
El Salvador Utilities	$ 850	$ 753	$ 647	13%	16%
Africa Utilities	458	386	422	19%	-9%
Europe Utilities	491	418	356	17%	17%
Corp/Other	10	8	10	25%	-20%
Eliminations	—	—	—	0%	0%
Total Corporate and Other	$1,809	$1,565	$1,435	16%	9%
Gross Margin					
El Salvador Utilities	$ 57	$ 47	$ 56	21%	-16%
Africa Utilities	47	(59)	64	180%	-192%
Europe Utilities	30	23	21	30%	10%
Corp/Other	(16)	(4)	3	-300%	-233%
Eliminations	—	—	—	0%	0%
Total Corporate and Other	$ 118	$ 7	$ 144	NM	-95%

Fiscal Year 2012 versus 2011

Excluding the unfavorable impact of foreign currency translation of $42 million, Corporate and Other revenue increased $286 million for 2012, or 18% from 2011 primarily due to:

- higher pass-through tariffs of $76 million in El Salvador primarily due to increased energy prices driven by higher fuel prices;
- higher volume and rates at our utility businesses in the Ukraine of $79 million; and
- the unfavorable impact of a mark-to-market derivative adjustment in 2011 at Sonel in Cameroon of $75 million.

Excluding the unfavorable impact of foreign currency translation of $3 million, Corporate and Other gross margin increased $114 million for 2012 from 2011. The increase was primarily due to:

- an increase of $107 million at Sonel primarily due to the unfavorable impact of a mark-to-market derivative adjustment in 2011 of $75 million as discussed above.

Fiscal Year 2011 versus 2010

Excluding the favorable impact of foreign currency translation of $14 million, primarily in Cameroon, Corporate and Other revenue increased $116 million from 2010 or 8%, from 2010. The increase was primarily due to:

- higher pass-through tariffs of $94 million in El Salvador primarily due to increased energy prices driven by higher fuel prices and drier weather; and
- higher rates at our utility businesses in the Ukraine of $71 million.

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, primarily in Cameroon, Corporate and Other gross margin decreased $133 million for 2011, or 92%, 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; and
- a decrease of $16 million in the Ukraine primarily due to higher fixed costs.

General and administrative expenses

General and administrative expenses includes 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 $90 million, or 23%, to $301 million in 2012 from 2011. The decrease was primarily due to reduction in business development and systems administration costs.

General and administrative expenses remained flat at $391 million in 2011 and 2010. A reduction of business development costs and SAP implementation costs was offset by DPL transaction costs.

Interest expense

Interest expense increased $19 million, or 1%, to $1.6 billion in 2012 from 2011. This increase was primarily due to debt at DPL, acquired in November 2011, additional indebtedness at the Parent Company to finance the acquisition of DPL, and less interest capitalization due to the commencement of operations at various projects. The increase was partially offset by a reduction in interest expense in Brazil, due to lower short-term interest rates, lower debt principal and favorable foreign currency translation, as well as lower interest expense for Cartagena, which was deconsolidated following the sale of 80% of our interest in the first quarter of 2012 and higher capitalized interest at Gener in 2012.

Interest expense increased $104 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, interest on value-added tax for 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 that was written off in Brazil in 2010.

Interest income

Interest income decreased $50 million, or 13%, to $349 million in 2012 from 2011. The decrease was mainly in Brazil, due to a reduction in interest-bearing assets, unfavorable foreign currency translation and lower interest rates, partially offset by inflation adjustments on interest-bearing assets and interest earned on receivables for spot sales in the Dominican Republic.

Interest income decreased $8 million, or 2%, to $399 million in 2011 from 2010. This 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.

Other income and expense

See discussion of the components of other income and expense in Note 20—*Other Income and Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K.

Goodwill impairment

The Company recognized goodwill impairment of $1.82 billion, $17 million and $21 million for the years ended December 31, 2012, 2011 and 2010, respectively. See Note 10 —*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 $73 million, $173 million and $304 million for the years ended December 31, 2012, 2011 and 2010, respectively. See Note 21—*Asset 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 $219 million in 2012 consisted primarily of the gain related to the sale of 80% of our interest in Cartagena, as well as the sale of certain investments in China. See Note 24—*Acquisitions and Dispositions* for further information on our gains at Cartagena and China.

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.

Foreign currency transaction gains (losses)

The following table summarizes foreign currency transaction gains (losses) for the years ended December 31, 2012, 2011 and 2010:

	2012	2011	2010
		(in millions)	
AES Corporation	$ 11	$(10)	$(50)
Chile	9	(19)	8
Philippines	(159)	3	8
Brazil	(16)	(12)	(6)
Argentina	(5)	16	12
Other	(7)	(17)	(5)
Total[(1)]	$(167)	$(39)	$(33)

(1) Includes gains (losses) of $(160) million, $44 million and $(10) million on foreign currency derivative contracts for the years ended December 31, 2012, 2011 and 2010, respectively.

The Company recognized foreign currency transaction losses of $167 million for the year ended December 31, 2012. These losses consisted primarily of losses in the Philippines and Brazil, partially offset by gains at The AES Corporation.

- Losses of $159 million in the Philippines were primarily due to unrealized foreign exchange losses on embedded derivatives as a result of the forecasted strengthening of the Philippine Peso, partially offset by gains from the 7% appreciation of the Philippine Peso on U.S. Dollar denominated debt at Masinloc, which had been a Philippine Peso functional currency subsidiary.
- Losses of $16 million in Brazil were primarily due to a 9% devaluation of the Brazilian Real resulting in losses mainly associated with U.S. Dollar denominated liabilities.
- Gains of $11 million at The AES Corporation were primarily due to increases in the valuation of intercompany notes receivable denominated in foreign currencies, resulting from the strengthening of the Euro and British Pound during the year, partially offset by losses related to foreign currency option purchases.

The Company recognized foreign currency transaction losses of $39 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 an unrealized 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 AES Argentina (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 intercompany notes receivable resulting from the weakening of the Euro and British Pound, and losses on foreign exchange options, partially offset by gains on third-party debt denominated in British Pounds and gains on foreign cash balances.
- Gains of $12 million in Argentina were primarily due to an unrealized 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 AES Argentina (an Argentine Peso functional currency subsidiary) associated with its U.S. Dollar denominated debt.

Other non-operating expense

Other non-operating expense was $50 million, $82 million and $7 million for the years ended December 31, 2012, 2011 and 2010, respectively. See Note 9—*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 $74 million, or 12%, to $708 million in 2012. The Company's effective tax rates were 225% for 2012 and 29% for 2011.

The net increase in the 2012 effective tax rate was principally due to a nondeductible impairment of goodwill at our U.S. utility, DPL. See Note 10—*Goodwill and Other Intangible Assets* for additional information regarding goodwill impairment.

Income tax expense on continuing operations increased $41 million, or 7%, to $634 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 fourth quarter of 2011 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 2011 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 Note 9—*Other Non-Operating Expense* and Note 21—*Asset Impairment Expense* for additional information regarding the impairments included in Item 8.— *Financial Statements and Supplementary Data* of this Form 10-K.

Net equity in earnings of affiliates

Net equity in earnings of affiliates increased $36 million, to $34 million in 2012 from a loss of $2 million in 2011. This increase was primarily due to increased tariff pricing, lower coal prices, and lower depreciation at Yangcheng in China in 2012. Additionally, there were impairment charges at AES Solar in 2011 of which our share was $36 million. This was partially offset by lower net income caused by higher electricity purchase costs at Guacolda.

Net equity in earnings of affiliates decreased $186 million, or 101%, to a loss of $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.

Income from continuing operations attributable to noncontrolling interests

Income from continuing operations attributable to noncontrolling interests decreased $528 million, or 49%, to $555 million in 2012. This decrease was primarily due to decreased gross margin at Eletropaulo as a result of the tariff reset and higher fixed costs.

Income from continuing operations attributable to noncontrolling interests increased $98 million, or 10%, to $1.1 billion in 2011. This increase was primarily due to the appreciation of the Brazilian Real at our Brazilian businesses 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.

Discontinued operations

Total discontinued operations was a net gain of $3 million for the year ended December 31, 2012, and a net loss of $45 million and $422 million for the years ended December 31, 2011 and 2010, respectively. See Note 23—*Discontinued Operations and Held for Sale Businesses* included in Item 8.— *Financial Statements and Supplementary Data* of this Form 10-K for further information.

Capital Resources and Liquidity

Overview

As of December 31, 2012, the Company had unrestricted cash and cash equivalents of $2.0 billion, of which approximately $0.3 billion was held at the Parent Company and qualified holding companies, and short term investments of $0.7 billion. In addition, we had restricted cash and debt service reserves of $1.3 billion. The Company also had non-recourse and recourse aggregate principal amounts of debt outstanding of $15.4 billion and $6.0 billion, respectively. Of the approximately $2.8 billion of our short-term non-recourse debt, $1.4 billion was presented as current because it is due in the next twelve months and $1.4 billion relates to the debt considered in default. 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 $11 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 Parent Company liquidity. See further discussion of Parent Company Liquidity below.

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 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 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 $15.4 billion of total non-recourse debt outstanding as of December 31, 2012, approximately $4.3 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 recourse debt, common stock and other securities. Similarly, at 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, 2012, 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 $568 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, 2012, we had $5 million in letters of credit outstanding, provided under the senior secured credit facility, and $215 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 year ended December 31, 2012, 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 *Key Trends and Uncertainties, Global Economic Conditions* discussion. 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, 2012, the Company had approximately $359 million and $24 million of trade accounts receivable related to certain of its generation and utility businesses in Latin America classified as other noncurrent assets and current trade accounts receivable, respectively. The noncurrent portion primarily consists of trade accounts receivable that, pursuant to amended agreements or government resolutions, have collection periods that extend beyond December 31, 2013, or one year past the latest balance sheet date. The Company believes such amounts are collectable based on collection history and performance under agreements. For example, since 2004, our subsidiaries in Argentina have entered into three agreements with the Argentine government called Fondos de inversion Mercado Electrico Mayorista ("Foninvemem Agreements"), in which our subsidiaries contributed a portion of their accounts receivable into a fund used to finance the construction of combined cycle and gas-fired plants. Our subsidiaries in Argentina have been collecting the accounts receivable from the combined cycle plants constructed under the first two Foninvemem Agreements since 2010 while the accounts receivable related to the third Foninvemem Agreement are not currently due as commercial operations of the related combined cycle and gas-fired plant are scheduled to begin in 2015. Additionally, our subsidiaries in Argentina have recently reached an agreement with the Argentine government to include certain outstanding receivables covered under government resolutions into the third Foninvemem Agreement. In August 2012, the Argentine government announced its intention of developing a new energy model that would apply to all energy sectors: generation, transmission and distribution companies. The new model is expected to provide enough recovery of costs incurred by the sectors as well as provide for a return on invested capital. To ensure timely collection across the energy sectors of new receivables as they arise, future tariff increases will be needed. No formal communication has been made by the Argentine government as to the timing and implementation of this new model. As of December 31, 2012, the Company had approximately $316 million of trade accounts receivable related to the Foninvemem Agreements and government resolutions classified as other noncurrent assets. See Item 1.—*Business* included in this Form 10-K for further information on these agreements.

Capital Expenditures

The Company spent $2.3 billion, $2.5 billion and $2.3 billion on capital expenditures in 2012, 2011 and 2010, respectively. A majority of these costs were funded with non-recourse debt consistent with our financial strategy. At December 31, 2012, the Company had a total of $1.2 billion of availability under long-term non-recourse construction credit facilities. 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, 2012, the Company had $3 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 2013. 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 proposed 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.

In 2012, the Company's subsidiaries operated businesses which had total approximate CO_2 emissions of 78.9 million metric tons of which approximately 39.9 million metric tons were emitted in the U.S. (both figures ownership adjusted). Approximately 1.4 million metric tons were emitted by our Warrior Run business, our only business located in a state 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.

Consolidated Cash Flows

At December 31, 2012, cash and cash equivalents increased $275 million from December 31, 2011 to $2.0 billion. The increase in cash and cash equivalents was due to $2.9 billion of cash provided by operating activities, $1.0 billion of cash used in investing activities, $1.74 billion of cash used in financing activities, a favorable effect of foreign currency exchange rates on cash of $5 million and a $131 million decrease in cash of discontinued and held-for-sale businesses.

At December 31, 2011, cash and cash equivalents decreased $811 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, $1.41 billion of cash provided by financing activities, an unfavorable effect of foreign currency exchange rates on cash of $122 million and a $79 million increase in cash of discontinued and held-for-sale businesses.

				$ Change	
	2012	**2011**	**2010**	**2012 vs. 2011**	**2011 vs. 2010**
			(in millions)		
Net cash provided by (used in) operating activities	$ 2,901	$ 2,884	$ 3,465	$ 17	$ (581)
Net cash provided by (used in) investing activities	(1,023)	(4,906)	(2,040)	3,883	(2,866)
Net cash provided by (used in) financing activities	(1,739)	1,412	(706)	(3,151)	2,118

Operating Activities

Operating cash flow for the year ended December 31, 2012 resulted primarily from the net loss adjusted for non-cash items, principally gains and losses on sales and disposals and impairment charges, depreciation and amortization and deferred income taxes, partially offset by a net use of cash for operating activities of $68 million in operating assets and liabilities. Other assets increased $589 million primarily due to an increase in noncurrent regulatory assets at Eletropaulo, resulting from higher priced energy purchases, regulatory charges and transmission costs which are recoverable through future tariff and the establishment of a noncurrent note receivable at Cartagena in Spain following the arbitration settlement, prior to its deconsolidation. Accounts receivable increased $241 million primarily due to lower collections at Eletropaulo and Andres as well as an increase in revenue at Sul and Kelanitissa. Net income tax payables decreased $47 million primarily from payments of income taxes exceeding accruals for new current tax liabilities. These uses of operating cash flows were offset by an increase of $335 million in other liabilities primarily due to an increase in noncurrent regulatory liabilities at Eletropaulo related to the tariff reset. Accounts payable and other current liabilities increased $330 million primarily due to an increase in current regulatory liabilities at Eletropaulo driven by the tariff reset, offset by a decrease in other current liabilities arising from value added tax payments. Prepaid expenses and other current assets provided $120 million primarily due to the recovery of value added taxes at our construction projects in Chile.

Net cash provided by operating activities was $2.9 billion for the year ended December 31, 2011. Operating cash flow resulted primarily from net income adjusted for non-cash items, principally depreciation and amortization, contingencies, deferred income taxes, losses on the extinguishment of debt, gains and losses on sales and disposals and impairment charges as well as a net favorable change of $52 million in operating assets and liabilities. Other liabilities increased $351 million primarily due to an increase in noncurrent regulatory liabilities at Eletropaulo and Sul as the result of lower prices paid for energy purchases compared with the charges recovered through the tariff. Accounts payable and other current liabilities increased $322 million primarily driven by an increase in current regulatory liabilities at Eletropaulo driven by the tariff reset, partially offset by the amount returned to consumers for regulatory liabilities and VAT on commercial losses reversal, as well as an increase in accrued interest on recourse debt at the Parent Company. Income tax payables, net increased $166 million primarily due to accruals for new current tax liabilities offset by payments of income taxes. These favorable changes were partially offset by increases of $403 million in other assets, $236 million in accounts receivable and $141 million in inventory. The increase in other assets was mainly explained by an increase in noncurrent regulatory assets at Eletropaulo, resulting from higher priced energy purchases, transmission costs and regulatory charges compared with charges recovered through the tariff. The increase in accounts receivable was primarily due to an increase in amounts billed at several businesses including Eletropaulo and new plants at Maritza and Angamos. The increase in inventory was primarily driven by higher coal purchases at Gener as well as increased inventory at Angamos as it started operations in 2011.

Net cash provided by operating activities was $3.5 billion for the year ended December 31, 2010. Operating cash flow resulted primarily from net income adjusted for non-cash items, principally depreciation and amortization, contingencies, deferred income taxes, gains and losses on sales and disposals and impairment charges, an undistributed gain from the sale of an equity method investment, as well as a net favorable change of $608 million in operating assets and liabilities. Prepaid expenses and other current assets decreased $385 million primarily due to a decrease in current regulatory assets, for the recovery of prior period tariff cycle energy purchases and regulatory charges at Eletropaulo and Sul. Other liabilities increased $257 million primarily driven by an increase in noncurrent regulatory liabilities at Eletropaulo as the result of lower prices paid for energy purchases and transmission costs compared with charges recovered through the tariff. Income tax payables, net increased $166 million primarily due to accruals for new current tax liabilities offset by payments of income taxes. Accounts payable and other current liabilities increased $136 million primarily driven by higher energy purchases at Gener, Eletropaulo and Sul, partially offset by a decrease in the current regulatory liability at Eletropaulo as a result of refunds to consumers of prior period costs through the tariff. These favorable changes were partially offset by an increase of $248 million in other assets and an increase of $98 million in accounts receivable. The increase in other assets was mainly an increase in noncurrent regulatory assets at Eletropaulo as a result of higher priced energy purchases, and regulatory charges compared with charges recovered through the tariff. The increase in accounts receivable was primarily due to an increase in revenue in Alicura and Gener and lower collections at Sonel and Lal Pir.

Net cash provided by operating activities increased $17 million, or 1%, to $2.9 billion during 2012 compared to 2011, mainly due to the following:

- US—an increase of $320 million at our utility businesses primarily due to the operations, net of debt service costs, of DPL which was acquired in November 2011;
- Andes—an increase of $57 million driven by cash provided by the operating activities of the new plant at Angamos, recovery of value added tax at Campiche and reduced working capital requirements at Gener, partially offset by reduced gross margin from Gener operations other than Angamos;
- Brazil—a decrease of $503 million at our utility businesses primarily driven by higher priced energy purchases, regulatory charges and transmission costs payments, higher operating and maintenance expenses and lower accounts receivable collections due to the lower tariff starting in July 2012 at Eletropaulo, partially offset by a lower payment of income taxes;
- MCAC—an increase of $25 million at our generation businesses primarily due to the operations of the Esti plant being back on line from June 2012 and higher volumes of PPA sales at Panama and lower coal volume and price in 2012 at Itabo, partially offset by lower collections and lower sales in the Dominican Republic and higher taxes paid at Panama;
- EMEA—an increase of $42 million driven primarily by cash provided by the operating activities of the new plant at Maritza partially offset by a loss in revenue from a generator failure at Ballylumford in Northern Ireland; and
- Asia—an increase of $88 million driven primarily by Masinloc in the Philippines due to higher demand and reduced working capital requirements.

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:

- US—a decrease of $131 million at our generation businesses primarily due to reduced operations in New York prior to its deconsolidation in December 2011, partially offset by the deconsolidation of Thames in 2011;
- Brazil—a decrease of $352 million at our utility businesses primarily driven by higher income tax payments of which $84 million was 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;

- Asia—a decrease of $56 million at Masinloc, due to lower gross margin.

Investing Activities

Net cash used in investing activities decreased $3.9 billion to $1.0 billion in 2012 compared to 2011. This decrease was largely attributable to the following:

- a decrease of $3.5 billion from acquisitions, net of cash acquired, primarily due to the acquisitions of DPL for $3.4 billion in November 2011 and our equity investment in Entek in February 2011 for $150 million;
- an increase of $315 million in sale of short-term investments, net of purchases, primarily due to an increase of $364 million at our Brazilian subsidiaries mostly due to the prepayment of debentures and working capital demands offset by a decrease of $37 million at Gener;
- a decrease of $312 million in debt service reserves and other assets primarily due to decreases of $222 million at the Parent Company related to the collateralization of a letter of credit for the Mong Duong project in 2011, $47 million at Sonel related to the repayment of loans in 2012 and $44 million due to the repayment of funds for construction at Changuinola;
- a decrease of $194 million in capital expenditures primarily due to decreases of $97 million at our wind projects, $89 at Angamos, $75 million at IPL, $73 million at Kribi, $64 million at our Brazilian subsidiaries, $57 million at Changuinola, $38 million at Maritza, $29 million at Sonel and $21 million at Saurashtra, in India. These decreases were partially offset by increases of $166 million at DPL, $70 million at our Mong Duong project, $49 million at Gener and $34 million at Esti; and
- an increase of $114 million in proceeds from government grants for asset construction for certain domestic wind projects including Laurel Mountain and Mountain View 4; partially offset by:
- a decrease of $288 million in proceeds from the sale of businesses, net of cash sold, primarily due to $890 million in net cash received for the Telecom sale in October 2011 within Brazil Utilities. These decreases were partially offset by proceeds of $228 million for the sale of Red Oak and Ironwood within US Generation, $10 million from the dissolution of the joint venture in Turkey with IC Ictas Energy Group and $164 million from the subsequent sale of three wholly-owned hydropower plants previously owned by the IC Ictas joint venture to our Entek joint venture in which we hold a 50% interest as well as $63 million from the sale of 80% of our interest in Cartagena within EMEA Generation and $122 million for the sale of Cili and several equity method investments in China within Asia Generation; and
- a decrease of $199 million in proceeds from a performance bond received at Maritza to compensate for construction delays in 2011.

Financing Activities

Net cash used in financing activities increased $3.2 billion to $1.74 billion in 2012 compared to net cash provided by financing activities of $1.41 billion in 2011. This net increase was primarily attributable to the following:

- a $3.9 billion decrease in proceeds from issuances of recourse and non-recourse debt including decreases of $3.3 billion at the Parent Company to partially fund the acquisition of DPL in 2011, $635 million at IPL mostly used to refinance debt in 2011 and $466 million at Gener used to refinance debt and fund the construction of Angamos in 2011, offset by an increase of $686 million at our Brazilian subsidiaries mostly related to the issuance of debentures; and

- a $758 million decrease of net borrowings under revolving credit facilities primarily related to $590 million at the Parent Company due to a $295 million payment in 2012 for the amount borrowed in 2011 as well as decreases of $69 million at AES Argentina due to a $35 million payment in 2012 for the amount borrowed in 2011 and $67 million at Changuinola; partially offset by:
- a $1.1 billion decrease in repayments of recourse and non-recourse debt, including decreases of $559 million at IPL, $271 million at Gener, $241 million at the Parent Company and $100 million at Sonel, offset by an increase of $181 million at Kribi; and
- a $193 million decrease in distributions to non-controlling interests, primarily due to decreases at our Brazilian subsidiaries as a result of lower net income;
- a $162 million decrease in payments for financing fees, attributable to decreases of $74 million at the Parent Company, $39 million at our Mong Duong project in Vietnam and $28 million at Gener.

Contractual Obligations

A summary of our contractual obligations, commitments and other liabilities as of December 31, 2012 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[5]
Debt Obligations[1]	$21,293	$ 2,844	$ 3,185	$ 5,098	$10,166	$—	12
Interest Payments on Long-Term Debt[2]	8,825	1,323	2,403	1,860	3,239	—	n/a
Capital Lease Obligations[3]	217	12	23	22	160	—	13
Operating Lease Obligations[3]	763	53	99	94	517	—	13
Electricity Obligations[3]	38,882	2,599	5,960	5,322	25,001	—	13
Fuel Obligations[3]	8,570	1,555	1,553	844	4,618	—	13
Other Purchase Obligations[3]	18,796	1,976	3,372	2,295	11,153	—	13
Other Long-Term Liabilities Reflected on AES's Consolidated Balance Sheet under GAAP[4]	854	1	260	64	356	173	n/a
Total	$98,200	$10,363	$16,855	$15,599	$55,210	$173	

(1) Includes recourse and non-recourse debt presented on the Consolidated Balance Sheet. See Note 12—*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, 2012 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, 2012.

(3) See Note 13—*Commitments* to the Consolidated Financial Statements included in Item 8 of this Form 10-K for further information.

(4) 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 11—*Regulatory Assets and Liabilities*), (2) contingencies (See Note 14—*Contingencies*), (3) pension and other post retirement employee benefit liabilities (see Note 15—*Benefit Plans*) or (4) any taxes (See Note 22—*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.

(5) 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" as of December 31, 2012 and 2011 as follows:

Parent Company Liquidity	2012	2011
	(in millions)	
Cash and cash equivalents	$ 1,970	$ 1,695
Less: Cash and cash equivalents at subsidiaries	(1,659)	(1,495)
Parent and qualified holding companies cash and cash equivalents	311	200
Commitments under Parent credit facilities	800	800
Less: Letters of credit under the credit facilities	(5)	(12)
Less: Borrowings under the credit facilities	—	(295)
Borrowings available under Parent credit facilities	795	493
Total Parent Company Liquidity	$ 1,106	$ 693

Recourse Debt:

Our recourse debt at year-end was approximately $6.0 billion and $6.5 billion in 2012 and 2011, respectively. The following table sets forth our Parent Company contingent contractual obligations as of December 31, 2012:

Contingent contractual obligations	Amount	Number of Agreements	Maximum Exposure Range for Each Agreement
	(in millions)		(in millions)
Guarantees	$568	19	<$1 -$237
Cash collateralized letters of credit	215	9	<$1 -$189
Letters of credit under the senior secured credit facility	5	6	<$1 -$2
Total	$788	34	

As of December 31, 2012, the Company had $3 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 2013. 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. In addition, we have an assets sale program through which we may have customary indemnity obligations under certain assets sale agreements. While we do not expect that we will be required to fund any material amounts under these contingent contractual obligations beyond 2012, 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.

The Company paid a dividend of 4 cents per share to its common stockholders during the fourth quarter of 2012. While we intend to continue payment of dividends and believe we will have sufficient liquidity to do so, we can provide no assurance we will be able to continue payment of dividends.

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, 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. 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, 2012, 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 $2.8 billion. The portion of current debt related to such defaults was $1.4 billion at December 31, 2012, all of which was non-recourse debt related to four subsidiaries—Maritza, Sonel, Kavarna and Saurashtra.

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, 2012 in order for such defaults to trigger an event of default or permit acceleration under such indebtedness. However, as a result of additional dispositions of assets, other significant reductions in asset carrying values or other matters in the future that may impact our financial position and results of operations or the financial position of the individual subsidiary, it is possible that one or more of these subsidiaries could fall within the definition of a "material subsidiary" and thereby upon an acceleration trigger an event of default and possible acceleration of the indebtedness under the AES Parent Company's outstanding debt securities.

Critical Accounting Estimates

The Consolidated Financial Statements of AES are prepared in conformity with U.S. 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's 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 be materially different than the reserve amounts.

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 provides 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. On January 3, 2013, the Controlled Foreign Corporation look-through rule was retroactively reinstated to January 1, 2012 for a period of two years through the American Taxpayer Relief Act of 2012. In determining the Company’s effective tax rate for the year ended December 31, 2012, the Company has excluded the benefits of this provision; however it expects to record the benefit of the retroactive reinstatement of the provision for 2012 in the first quarter of 2013. There can be no assurance that this provision will continue to be extended beyond this two year period. Accordingly, if this provision is not renewed, our expected effective tax rate could increase by amounts that may 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. The Company makes considerable judgments in its impairment evaluations of goodwill and long-lived assets; however, the fair value determination is typically the most judgmental part in 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 10—*Goodwill and Other Intangible Assets,* Note 21—*Asset Impairment Expense* and Note 9—*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 Activities 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

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

The Company adopted the new accounting standard on comprehensive income, which became effective January 1, 2012. In addition, the Company early adopted the new accounting standard on the impairment testing of intangible assets. 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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Overview Regarding Market Risks

Our generation and utilities business lines are exposed to and proactively manage market risk. 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 varying degrees 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; 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

Although we prefer to hedge our exposure to the impact of market fluctuations in the price of electricity, fuels and environmental credits, some of our generation businesses operate under short-term sales or under contract sales that leave an un-hedged exposure on some of capacity, or through imperfect pass throughs. At our generation businesses, for 2013-2015 75% to 80% of our variable margin is hedged against changes in commodity prices. In our utility businesses, we may be exposed to commodity price movements depending on our excess or shortfall of generation relative to load obligations, and sharing or pass through mechanisms. At our utility businesses, for 2013-2015 85% to 90% of our variable margin is insulated from changes in commodity prices. 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 contract sales 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 or to the extent indexation is not perfectly matched to the business drivers.

AES businesses will see changes in variable margin performance as global commodity prices shift. For 2013, we project pretax earnings exposure on a 10% move in commodity prices would be approximately $25 million for coal, $15 million for oil and $20 million for 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, and our sensitivity to changes in commodity prices generally increases in later years with reduced hedge levels at some our businesses.

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, bidding strategies and regulatory interventions such as price caps. Operational flexibility changes the shape of our sensitivities. For instance, certain 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 the US SBU, the generation businesses are largely contracted but may have residual risk to the extent contracts are not perfectly indexed to the business drivers. IPL sells power at wholesale once retail demand is served, so retail sales demand may affect commodity exposure. 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; DPL sells generation in excess of its retail demand under short-term sales; and the outcome of the DPL regulatory filing may affect our level of commodity price exposure over time. 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.

For the Andes SBU, our business in Chile owns assets in the central and northern regions of the country and has a portfolio of contract sales in both. While we have been adding coal-fired generation to our portfolio in Chile, a small amount of efficient generation is sold into the spot market. Other assets in Chile include natural gas/diesel, hydroelectric and biomass generation facilities. Generators with oil or oil-linked fuel generally set power prices in these markets impacting spot power margins. In our other Andes SBU markets, Colombia and Argentina, we operate under a short-term sales strategy and have commodity exposure to un-hedged volumes. Because we own hydroelectric assets in Colombia, contracts are not indexed to fuel. In Argentina some prices are set according to government rules that result in commodity exposure based on several factors, one of which is the spread between the cost of coal-fired and oil-fired generation.

The businesses in the MCAC SBU have commodity exposure on un-hedged volumes. Panama is largely contracted under a portfolio of contract sales, and the un-hedged portion of our hydroelectric assets in Panama is sensitive to changes in spot power prices which may be driven by oil prices in some time periods. In the Dominican Republic, we own natural gas-fired assets contracted under a portfolio of contract sales and a coal-fired asset contracted with a single contract, and both contract and spot prices may move with commodity prices.

In the EMEA SBU, our Kilroot facility operates on a short-term sales strategy. The commodity risk at our Kilroot business is due to the dark spread, the difference between electricity price and our coal based variable dispatch cost, 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 contract, which would impact our commodity exposure. Our operations in Turkey are sensitive to the spread between power and natural gas prices, both of which have historically demonstrated a relationship to oil. As a result of these relationships, falling oil prices could compress margins realized at the business.

In the Asia SBU, our Masinloc business is a coal-fired generation facility which hedges its output under a portfolio of contract sales that are indexed to fuel prices, with generation in excess of contract volume sold in the spot market. 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, Dominican Peso, Euro, Indian Rupee, Kazakhstani Tenge, Philippine Peso, and Ukrainian Hryvnia. 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.

We have entered into hedges to partially mitigate the exposure of earnings translated into the U.S. Dollar to foreign exchange volatility. As of December 31, 2012, assuming a 10% U.S. Dollar appreciation, adjusted pretax earnings attributable to foreign subsidiaries exposed to movement in the exchange rate of the Brazilian Real, Colombian Peso, 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 are projected to be reduced by approximately $25 million, $10 million, $5 million, and $15 million, respectively, for 2013. These numbers have been produced by applying a one-time 10% U.S. Dollar appreciation to forecasted exposed pretax earnings for 2013 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 are unwound. Additionally, updates to the forecasted pretax earnings exposed to foreign exchange risk may result in further modification. The sensitivities presented do not capture the impacts of any administrative market restrictions or currency inconvertibility.

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. Most of our interest rate risk is related to non-recourse financings at our businesses.

As of December 31, 2012, the portfolio's pretax earnings exposure for 2013 to a 100 basis point increase in interest rates for our Argentine Peso, Brazilian Real, Columbian Peso, British Pound, Euro, Indian Rupee, Philippine Peso, Kazakhstani Tenge, and U.S. Dollar denominated debt would be approximately $25 million based on the impact of a one-time, 100 basis point upward shift in interest rates on interest expense for the debt denominated in these currencies. The amounts 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, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2012. 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 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 also 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, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, 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.

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, 2012, 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 26, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

McLean, Virginia
February 26, 2013

THE AES CORPORATION

CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2012 AND 2011

	2012	2011
	(in millions, except share and per share data)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 1,970	$ 1,695
Restricted cash	751	477
Short-term investments	696	1,356
Accounts receivable, net of allowance for doubtful accounts of $309 and $273, respectively	2,712	2,522
Inventory	769	775
Deferred income taxes	222	454
Prepaid expenses	231	157
Other current assets	1,114	1,560
Current assets of discontinued operations and held for sale assets	—	233
Total current assets	8,465	9,229
NONCURRENT ASSETS		
Property, Plant and Equipment:		
Land	1,008	1,089
Electric generation, distribution assets and other	31,837	31,068
Accumulated depreciation	(9,723)	(8,944)
Construction in progress	2,791	1,788
Property, plant and equipment, net	25,913	25,001
Other Assets:		
Investments in and advances to affiliates	1,196	1,422
Debt service reserves and other deposits	565	876
Goodwill	1,999	3,820
Other intangible assets, net of accumulated amortization of $276 and $164, respectively	429	545
Deferred income taxes	996	715
Other noncurrent assets	2,242	2,346
Noncurrent assets of discontinued operations and held for sale assets	25	1,392
Total other assets	7,452	11,116
TOTAL ASSETS	$41,830	$45,346
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 2,638	$ 2,008
Accrued interest	295	327
Accrued and other liabilities	2,532	3,389
Non-recourse debt including $287 and $259, respectively, related to variable interest entities	2,843	2,123
Recourse debt	11	305
Current liabilities of discontinued operations and held for sale businesses	—	286
Total current liabilities	8,319	8,438
NONCURRENT LIABILITIES		
Non-recourse debt including $1,187 and $1,156, respectively, related to variable interest entities	12,568	13,412
Recourse debt	5,951	6,180
Deferred income taxes	1,238	1,321
Pension and other post-retirement liabilities	2,456	1,729
Other noncurrent liabilities	3,706	3,111
Noncurrent liabilities of discontinued operations and held for sale businesses	—	1,348
Total noncurrent liabilities	25,919	27,101
Commitments and Contingencies (see Notes 13 and 14)		
Cumulative preferred stock of subsidiaries	78	78
EQUITY		
THE AES CORPORATION STOCKHOLDERS' EQUITY		
Common stock ($0.01 par value, 1,200,000,000 shares authorized; 810,679,839 issued and 744,263,855 outstanding at December 31, 2012 and 807,573,277 issued and 765,186,316 outstanding at December 31, 2011)	8	8
Additional paid-in capital	8,525	8,507
Retained earnings (accumulated deficit)	(264)	678
Accumulated other comprehensive loss	(2,920)	(2,758)
Treasury stock, at cost (66,415,984 and 42,386,961 shares at December 31, 2012 and 2011, respectively	(780)	(489)
Total The AES Corporation stockholders' equity	4,569	5,946
NONCONTROLLING INTERESTS	2,945	3,783
Total equity	7,514	9,729
TOTAL LIABILITIES AND EQUITY	$41,830	$45,346

See Accompanying Notes to these Consolidated Financial Statements

THE AES CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS
YEARS ENDED DECEMBER 31, 2012, 2011, AND 2010

	2012	2011	2010
	(in millions, except per share amounts)		
Revenue:			
Regulated	$ 9,925	$ 9,504	$ 8,910
Non-Regulated	8,216	7,419	6,533
Total revenue	18,141	16,923	15,443
Cost of Sales:			
Regulated	(8,433)	(7,134)	(6,497)
Non-Regulated	(5,994)	(5,726)	(5,126)
Total cost of sales	(14,427)	(12,860)	(11,623)
Gross margin	3,714	4,063	3,820
General and administrative expenses	(301)	(391)	(391)
Interest expense	(1,572)	(1,553)	(1,449)
Interest income	349	399	407
Other expense	(93)	(153)	(232)
Other income	105	149	100
Gain on sale of investments	219	8	—
Goodwill impairment	(1,817)	(17)	(21)
Asset impairment expense	(73)	(173)	(304)
Foreign currency transaction losses	(167)	(39)	(33)
Other non-operating expense	(50)	(82)	(7)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES AND EQUITY IN EARNINGS OF AFFILIATES	314	2,211	1,890
Income tax expense	(708)	(634)	(593)
Net equity in earnings (losses) of affiliates	34	(2)	184
INCOME (LOSS) FROM CONTINUING OPERATIONS	(360)	1,575	1,481
Loss from operations of discontinued businesses, net of income tax expense (benefit) of $3, $(26) and $(284), respectively	(13)	(131)	(486)
Net gain from disposal and impairments of discontinued businesses, net of income tax expense of $68, $300 and $132, respectively	16	86	64
NET INCOME (LOSS)	(357)	1,530	1,059
Noncontrolling interests:			
Less: Income from continuing operations attributable to noncontrolling interests	(555)	(1,083)	(985)
Less: Income from discontinued operations attributable to noncontrolling interests	—	(389)	(65)
Total net income attributable to noncontrolling interests	(555)	(1,472)	(1,050)
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION	$ (912)	$ 58	$ 9
AMOUNTS ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS:			
Income (loss) from continuing operations, net of tax	$ (915)	$ 492	$ 496
Income (loss) from discontinued operations, net of tax	3	(434)	(487)
Net income (loss)	$ (912)	$ 58	$ 9
BASIC EARNINGS PER SHARE:			
Income (loss) from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ (1.21)	$ 0.63	$ 0.64
Loss from discontinued operations attributable to The AES Corporation common stockholders, net of tax	—	(0.56)	(0.63)
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$ (1.21)	$ 0.07	$ 0.01
DILUTED EARNINGS PER SHARE:			
Income (loss) from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ (1.21)	$ 0.63	$ 0.64
Loss from discontinued operations attributable to The AES Corporation common stockholders, net of tax	—	(0.56)	(0.63)
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$ (1.21)	$ 0.07	$ 0.01
DIVIDENDS DECLARED PER COMMON SHARE	$ 0.08	$ —	$ —

See Accompanying Notes to these Consolidated Financial Statements

THE AES CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
YEARS ENDED DECEMBER 31, 2012, 2011, AND 2010

	2012	2011	2010
		(in millions)	
NET INCOME (LOSS)	$ (357)	$ 1,530	$ 1,059
Available-for-sale securities activity:			
Change in fair value of available-for-sale securities, net of income tax (expense) benefit of $0, $0 and $3, respectively	1	1	(5)
Reclassification to earnings, net of income tax (expense) benefit of $0, $0 and $0, respectively	(1)	(2)	—
Total change in fair value of available-for-sale securities	—	(1)	(5)
Foreign currency translation activity:			
Foreign currency translation adjustments, net of income tax (expense) benefit of $0, $18 and $(11), respectively	(247)	(484)	468
Reclassification to earnings, net of income tax (expense) benefit of $0, $0 and $0, respectively	37	188	142
Total foreign currency translation adjustments	(210)	(296)	610
Derivative activity:			
Change in derivative fair value, net of income tax (expense) benefit of $35, $108 and $56, respectively	(134)	(379)	(242)
Reclassification to earnings, net of income tax (expense) benefit of $(56), $(22) and $(41), respectively	177	137	162
Total change in fair value of derivatives	43	(242)	(80)
Pension activity:			
Prior service cost, net of income tax (expense) benefit of $0, $0, $0, respectively	(1)	—	—
Net actuarial (loss) for the period, net of income tax (expense) benefit of $300, $117 and $57, respectively	(587)	(223)	(111)
Amortization of net actuarial loss, net of income tax (expense) benefit of $(15), $(6) and $(12), respectively	24	13	23
Total pension adjustments	(564)	(210)	(88)
OTHER COMPREHENSIVE INCOME (LOSS)	(731)	(749)	437
COMPREHENSIVE INCOME (LOSS)	(1,088)	781	1,496
Less: Comprehensive loss (income) attributable to noncontrolling interests	14	(1,098)	(1,108)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION	$(1,074)	$ (317)	$ 388

See Accompanying Notes to these Consolidated Financial Statements

THE AES CORPORATION

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
YEARS ENDED DECEMBER 31, 2012, 2011, AND 2010

	THE AES CORPORATION STOCKHOLDERS							
	Common Stock		Treasury Stock		Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Loss	Noncontrolling Interests
	Shares	Amount	Shares	Amount				
	(in millions)							
Balance at January 1, 2010	677.2	$ 7	9.5	$(126)	$6,868	$ 650	$(2,724)	$ 4,205
Net income	—	—	—	—	—	9	—	1,050
Total change in fair value of available-for-sale securities, net of income tax	—	—	—	—	—	—	(5)	—
Total foreign currency translation adjustment, net of income tax	—	—	—	—	—	—	486	124
Total change in derivative fair value, including a reclassification to earnings, net of income tax	—	—	—	—	—	—	(80)	—
Total pension adjustments, net of income tax	—	—	—	—	—	—	(22)	(66)
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 and exercise of stock-based compensation benefit plans, net of income tax	2.2	—	(0.6)	9	35	—	—	—
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
Total change in fair value of available-for-sale securities, net of income tax	—	—	—	—	—	—	(1)	—
Total foreign currency translation adjustment, net of income tax	—	—	—	—	—	—	(143)	(153)
Total change in derivative fair value, including a reclassification to earnings, net of income tax	—	—	—	—	—	—	(190)	(52)
Total pension adjustments, net of income tax	—	—	—	—	—	—	(41)	(169)
Capital contributions from noncontrolling interests	—	—	—	—	—	—	—	8
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(1,254)
Disposition of businesses	—	—	—	—	—	—	—	(27)
Acquisition of treasury stock	—	—	25.5	(279)	—	—	—	—
Issuance and exercise of stock-based compensation benefit plans, net of income tax	2.7	—	(0.4)	6	44	—	—	—
Sale of subsidiary shares to noncontrolling interests	—	—	—	—	19	—	—	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
Net income (loss)	—	—	—	—	—	(912)	—	555
Total foreign currency translation adjustment, net of income tax	—	—	—	—	—	—	(90)	(120)
Total change in derivative fair value, including a reclassification to earnings, net of income tax	—	—	—	—	—	—	53	(10)
Total pension adjustments, net of income tax	—	—	—	—	—	—	(125)	(439)
Capital contributions from noncontrolling interests	—	—	—	—	—	—	—	30
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(802)
Disposition of businesses	—	—	—	—	—	—	—	(44)
Acquisition of treasury stock	—	—	24.8	(301)	—	—	—	—
Issuance and exercise of stock-based compensation benefit plans, net of income tax	3.1	—	(0.8)	10	37	—	—	—
Dividends declared on common stock ($0.08 per share)	—	—	—	—	(30)	(30)	—	—
Sale of subsidiary shares to noncontrolling interests	—	—	—	—	7	—	—	5
Acquisition of subsidiary shares from noncontrolling interests	—	—	—	—	4	—	—	(13)
Balance at December 31, 2012	810.7	$ 8	66.4	$(780)	$8,525	$(264)	$(2,920)	$ 2,945

See Accompanying Notes to these Consolidated Financial Statements

THE AES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
YEARS ENDED DECEMBER 31, 2012, 2011, AND 2010

	2012	2011	2010
		(in millions)	
OPERATING ACTIVITIES:			
Net income (loss)	$ (357)	$ 1,530	$ 1,059
Adjustments to net income (loss):			
Depreciation and amortization	1,394	1,262	1,178
Gain from sale of investments and impairment expense	1,766	386	1,313
Deferred income taxes	162	(199)	(418)
Provisions for contingencies	47	30	37
Loss on the extinguishment of debt	7	62	34
(Gain) loss on disposal and impairment write-down—discontinued operations	(84)	(388)	(209)
Undistributed gain from sale of equity method investment	—	—	(106)
Other	34	149	(31)
Changes in operating assets and liabilities, net of effects of acquisitions:			
(Increase) decrease in accounts receivable	(241)	(236)	(98)
(Increase) decrease in inventory	24	(141)	10
(Increase) decrease in prepaid expenses and other current assets	120	(7)	385
(Increase) decrease in other assets	(589)	(403)	(248)
Increase (decrease) in accounts payable and other current liabilities	330	322	136
Increase (decrease) income tax payables, net	(47)	166	166
Increase (decrease) in other liabilities	335	351	257
Net cash provided by operating activities	2,901	2,884	3,465
INVESTING ACTIVITIES:			
Capital expenditures	(2,236)	(2,430)	(2,310)
Acquisitions—net of cash acquired	(20)	(3,562)	(254)
Proceeds from the sale of businesses, net of cash sold	639	927	595
Proceeds from the sale of assets	46	117	23
Sale of short-term investments	6,437	6,075	5,786
Purchase of short-term investments	(5,907)	(5,860)	(5,795)
(Increase) decrease in restricted cash	(43)	61	(104)
(Increase) decrease in debt service reserves and other assets	28	(284)	(56)
Affiliate advances and equity investments	(89)	(155)	(97)
Proceeds from performance bond	—	199	—
Proceeds from government grants for asset construction	122	8	75
Proceeds from loan repayments	1	—	132
Other investing	(1)	(2)	(35)
Net cash used in investing activities	(1,023)	(4,906)	(2,040)
FINANCING ACTIVITIES:			
(Repayments) borrowings under the revolving credit facilities, net	(321)	437	78
Issuance of recourse debt	—	2,050	—
Issuance of non-recourse debt	1,391	3,218	1,940
Repayments of recourse debt	(235)	(476)	(914)
Repayments of non-recourse debt	(1,325)	(2,217)	(1,945)
Issuance of common stock	—	—	1,567
Payments for financing fees	(40)	(202)	(61)
Distributions to noncontrolling interests	(895)	(1,088)	(1,245)
Contributions from noncontrolling interests	43	6	—
Dividends paid on AES common stock	(30)	—	—
Financed capital expenditures	(34)	(31)	(23)
Purchase of treasury stock	(301)	(279)	(99)
Other financing	8	(6)	(4)
Net cash (used in) provided by financing activities	(1,739)	1,412	(706)
Effect of exchange rate changes on cash	5	(122)	8
(Increase) decrease in cash of discontinued and held for sale businesses	131	(79)	34
Total increase (decrease) in cash and cash equivalents	275	(811)	761
Cash and cash equivalents, beginning	1,695	2,506	1,745
Cash and cash equivalents, ending	$ 1,970	$ 1,695	$ 2,506
SUPPLEMENTAL DISCLOSURES:			
Cash payments for interest, net of amounts capitalized	$ 1,509	$ 1,442	$ 1,462
Cash payments for income taxes, net of refunds	$ 647	$ 971	$ 698
SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES:			
Assets acquired in noncash asset exchange	$ 12	$ 20	$ 42

See Accompanying Notes to these Consolidated Financial Statements

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.

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. Intercompany transactions and balances are 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, our utility in Ohio, 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.

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.

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 23—*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 or 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.

COMPREHENSIVE INCOME—In June 2011, the FASB issued ASU No. 2011-05, "*Comprehensive Income (Topic 220): Presentation of Comprehensive Income*" ("ASU No. 2011-05") which requires comprehensive income to be reported in either a single statement or in two consecutive statements reporting net income and other comprehensive income. The amendment does not change what items are reported in other comprehensive income or the U.S. GAAP requirement to report the reclassification of items from other comprehensive income to net income. The Company adopted ASU No. 2011-05 on January 1, 2012 and chose to report comprehensive income in two consecutive statements by adding a new consolidated statement of comprehensive income. To be consistent with this new presentation, the Company has presented consolidated statements of comprehensive income for each year in the three-year period ended December 31, 2012 in these consolidated financial statements. As ASU No. 2011-05 impacts financial statement presentation only, the adoption did not have an impact on the Company's historical financial position or results of operations and is not expected to have an impact in future periods.

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 implied goodwill and long-lived assets determined using discounted cash flows valuation models for impairment evaluation purposes qualify as Level 3.

Any transfers between all levels within 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, that mature within three months or less from the date of purchase, to be cash and cash equivalents. The carrying amounts of such balances approximate fair value.

RESTRICTED CASH AND DEBT SERVICE RESERVES—These include cash balances 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.

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 uncollectible 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.

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 cost 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, liquidated damages recovered for construction delays 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.

The Company's Brazilian subsidiaries, which include both generation and distribution companies, operate under concession contracts. Certain estimates are utilized to determine depreciation expense for the Brazilian subsidiaries, including the useful lives of the property, plant and equipment and the amounts to be recovered at the end of the concession contract. The amounts to be recovered under these concession contracts are based on estimates that are inherently uncertain and actual amounts recovered may differ from those estimates.

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, or 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. 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 net income.

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 financing 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 Statements 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 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 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.

Goodwill is evaluated for impairment either under the qualitative assessment option or the two-step test approach depending on facts and circumstances of a reporting unit. Examples of such facts and circumstances include: the excess of fair value over carrying amount in the last valuation, or changes in business environment. If the Company determines it is "more likely than not" that the fair value of a reporting unit is greater than its carrying amount, the two-step impairment test is unnecessary. When goodwill is evaluated for impairment using the two step test, the carrying amount of a reporting unit is compared to its fair value in Step 1 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. When a Step 2 is necessary, 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 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.

In July 2012, the FASB issued ASU No. 2012-02, *Testing Indefinite-Lived Intangible Assets for Impairment* (ASU No. 2012-02), which amended the existing guidance for indefinite-lived intangible assets impairment testing. Under the amendments in ASU No. 2012-02, an entity has the option to first assess qualitative factors to determine whether the existence of events or circumstances indicate that it is more likely than not that an intangible asset is impaired. If, after assessing the totality of events and circumstances, an entity determines that it is not more likely than not that an intangible asset is impaired, then the entity is not required to take further action. An entity also has the option to bypass the qualitative assessment for any intangible asset in any period and proceed directly to performing the quantitative impairment test. ASU No. 2012-02 is effective for annual and interim impairment tests performed for fiscal periods beginning on or after September 15, 2012 and early adoption is permitted. AES elected to adopt ASU No. 2012-02 early for its 2012 annual intangible asset impairment evaluations performed at October 1 and qualitatively assessed certain of its intangible assets. The adoption did not have an impact on the Company's financial position, results of operations or cash flows and is not expected to have an impact in future periods.

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 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 income from continuing operations.

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—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 as an approximation of certain profit sharing arrangements. 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—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. The Company does not recognize guarantees given to third parties for its subsidiaries' performance.

TRANSFER OF FINANCIAL ASSETS—As of December 31, 2012, the Company has $50 million recognized as accounts receivable and as an associated secured borrowing on its Consolidated Balance Sheet. IPL, the Company's integrated utility in Indianapolis, has securitized these accounts receivable through IPL Funding, a special-purpose entity. Under the arrangement, 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. 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. Accumulated foreign currency translation adjustments are reclassified to net income only when realized upon sale or upon complete or substantially complete liquidation of the investment in a foreign entity.

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.

SHARE-BASED COMPENSATION—The Company grants share-based compensation in the form of stock options and restricted stock units. The expense is based on the grant-date fair value of the equity or liability instrument issued and is recognized 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—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. See the Company's fair value policy and Note 4—*Fair Value* for additional discussion regarding the determination of the fair value. 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.

Derivatives primarily consist of interest rate swaps, cross-currency swaps, foreign currency instruments, and commodity derivatives. The Company enters into various derivative transactions in order to hedge its exposure to certain market risks, primarily interest rate, foreign currency and commodity price risks. Regarding interest rate risk, AES and its subsidiaries generally utilize variable rate debt financing for construction projects and operations so 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 and are typically designated as cash flow hedges. Regarding foreign currency risk, we are exposed to it as a result of our investments in foreign subsidiaries and affiliates that may be impacted by significant fluctuations in foreign currency exchange rates so foreign currency options and forwards are utilized, where deemed appropriate, to manage the risk related to these fluctuations. Cross-currency swaps are utilized in certain instances to manage the risk related to fluctuations in both interest rates and certain foreign currencies. In addition, certain of our subsidiaries have entered into contracts which contain embedded derivatives as a portion of the contracts is denominated in a currency other than the functional or local currency of that subsidiary or the currency of the item. Regarding 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. We use an overall hedging strategy, not just derivatives, to hedge our financial performance against the effects of fluctuations in commodity prices.

The accounting standards for derivatives and hedging enable companies to designate qualifying derivatives as hedging instruments based on the exposure being hedged. The Company only has cash flow 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. For all designated and qualifying hedges, 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 no longer 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.

While derivative transactions are not entered into for trading purposes, some contracts are not eligible for hedge accounting. Changes in the fair value of derivatives not designated and qualifying as cash flow hedges are immediately recognized in earnings. Regardless of when gains or losses on derivatives (including all those where the fair value measurement is classified as Level 3) are recognized in earnings, they are generally classified as follows: 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 and other derivatives. However, gains and losses on interest rate and cross-currency derivatives are classified as foreign currency transaction gains and losses if they offset the remeasurement of the foreign currency-denominated debt being hedged by the cross-currency swaps and the amount reclassified from AOCL to cost of sales to offset depreciation where the variable-rate interest capitalized as part of the asset was hedged during its construction. Cash flows arising from derivatives are included in the Consolidated Statements of Cash Flows as an operating activity given the nature of the underlying risk being economically hedged and the lack of significant financing elements, except that cash flows on designated and qualifying hedges of variable-rate interest during construction are classified as an investing activity.

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.

2. INVENTORY

As of December 31, 2012, 78% of the Company's inventory was valued using average cost, 14% 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, 2012 and 2011:

	2012	2011
	(in millions)	
Coal, fuel oil and other raw materials	$373	$434
Spare parts and supplies	396	341
Total	$769	$775

3. PROPERTY, PLANT AND 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. The amounts are stated net of impairment losses recognized as further discussed in Note 21—*Asset Impairment Expense.*

	Estimated Useful Life	December 31, 2012	December 31, 2011
	(in years)	(in millions)	
Electric generation and distribution facilities	5 - 68	$27,586	$26,821
Other buildings	3 - 50	2,840	2,924
Furniture, fixtures and equipment	3 - 31	472	476
Other	1 - 46	939	847
Total electric generation and distribution assets and other		31,837	31,068
Accumulated depreciation		(9,723)	(8,944)
Net electric generation and distribution assets and other[1][2]		$22,114	$22,124

(1) Net electric generation and distribution assets and other related to our held for sale businesses of $1.2 billion as of December 31, 2011, were excluded from the table above and were included in the noncurrent assets of discontinued and held for sale businesses in the consolidated balance sheet. There were no amounts excluded as of December 31, 2012.

(2) Net electric generation and distribution assets, and other include unamortized internal use software costs of $153 million and $156 million as of December 31, 2012 and 2011, respectively.

The following table summarizes depreciation expense (including the amortization of assets recorded under capital leases), amortization of internal use software and interest capitalized during development and construction on qualifying assets for the years ended December 31, 2012, 2011 and 2010:

	2012	2011	2010
		(in millions)	
Depreciation expense (including amortization of assets recorded under capital leases)	$1,251	$1,154	$1,010
Amortization of internal use software	48	46	50
Interest capitalized during development and construction	111	176	188

Property, plant and equipment, net of accumulated depreciation, of $16.0 billion and $15.2 billion was mortgaged, pledged or subject to liens as of December 31, 2012 and 2011, respectively.

The following table summarizes regulated and non-regulated generation and distribution property, plant and equipment and accumulated depreciation as of December 31, 2012 and 2011:

	December 31, 2012	December 31, 2011
	(in millions)	
Regulated assets	$14,650	$14,398
Regulated accumulated depreciation	(5,221)	(5,029)
Regulated generation, distribution assets and other, net	9,429	9,369
Non-regulated assets	17,187	16,670
Non-regulated accumulated depreciation	(4,502)	(3,915)
Non-regulated generation, distribution assets and other, net	12,685	12,755
Net electric generation and distribution assets and other	$22,114	$22,124

The following table summarizes the amounts recognized, which were related to asset retirement obligations, for the years ended December 31, 2012 and 2011:

	2012	2011
	(in millions)	
Balance at January 1	$117	$ 88
Additional liabilities incurred	3	1
Assumed in business combination	—	24
Liabilities settled	(3)	—
Accretion expense	7	6
Change in estimated cash flows	3	(1)
Translation adjustments	1	(1)
Balance at December 31	$128	$117

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. There were no legally restricted assets for purposes of settling asset retirement obligations at December 31, 2012. The fair value of legally restricted assets for purposes of settling asset retirement obligations was $1 million at December 31, 2011.

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, 2012, DP&L had $36 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, 2012 is as follows:

	DP&L Share		DP&L Investment ($ in millions)		
	Ownership	Production Capacity (MW)	Gross Plant In Service	Accumulated Depreciation	Construction Work In Process
Production units:					
Beckjord Unit 6	50%	207	$—	$—	$—
Conesville Unit 4	17%	129	41	3	11
East Bend Station	31%	186	8	2	3
Killen Station	67%	402	299	—	5
Miami Fort Units 7 and 8	36%	368	213	7	3
Stuart Station	35%	808	200	6	12
Zimmer Station	28%	365	169	12	2
Transmission	various	—	39	3	—
Total		2,465	$969	$ 33	$ 36

4. FAIR VALUE

The fair value of current financial assets and liabilities, debt service reserves and other deposits approximate their reported carrying amounts. 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.

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, the value estimated under the income approach is often the most representative of fair value. Assets and liabilities are 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.

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

Any Level 1 derivative instruments 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. There have been no transfers between Level 1 and Level 2.

For all derivatives, with the exception of any 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. Among the most common market data inputs used in the income approach include 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. When significant inputs are not observable, the Company uses relevant techniques to best estimate the inputs, such as regression analysis or prices for similarly traded instruments available in the market.

For derivatives for which there is a standard industry valuation model, the Company uses a third-party treasury and risk management software product that uses a standard model and observable inputs to estimate the fair value. For these derivatives, the Company performs analytical procedures and makes comparisons to other third-party information in order to assess the reasonableness of the fair value. For derivatives for which there is not a standard industry valuation model (such as PPAs and fuel supply agreements that are derivatives or include embedded derivatives), the Company has created internal valuation models to estimate the fair value, using observable data to the extent available. At each quarter-end, the models for the commodity and foreign currency-based derivatives are generally prepared and reviewed by employees who globally manage the respective commodity and foreign currency risks and are analytically reviewed independent of those employees.

Those cash flows are then discounted using the relevant spot benchmark interest rate (such as LIBOR or EURIBOR). The Company then makes a credit valuation adjustment ("CVA") by further discounting the cash flows for nonperformance or credit risk based on the observable or estimated debt spread of the Company's subsidiary or its counterparty and the tenor of the respective derivative instrument. The CVA for asset positions is based on the counterparty's credit ratings and debt spreads. The CVA for liability positions is based on the Parent Company's or the subsidiary's current debt spread. In the absence of readily obtainable credit information, the Parent Company's or the subsidiary's estimated credit rating (based on applying an standard industry model to historical financial information and then considering other relevant information) and spreads of comparably rated entities or the respective country's debt spreads are used as a proxy. All derivative instruments are analyzed individually and are subject to unique risk exposures.

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 market or market-corroborated data readily available, requiring 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 classified as Level 3 when the use of unobservable inputs is significant. When the use of unobservable inputs is insignificant, assets and liabilities are classified as Level 2. Transfers between Level 3 and Level 2 are determined as of the end of the reporting period and result from changes in significance of unobservable inputs used to calculate the CVA.

The following table summarizes the significant unobservable inputs used for the Level 3 derivative assets (liabilities) at December 31, 2012:

Type of Derivative	Fair Value (in millions)	Unobservable Input	Amount or Range (Weighted Average)
Interest rate	$(412)	Subsidiaries' credit spreads	2.6% – 9.8% (6.5%)
Foreign currency:			
Embedded derivative—			
Argentine Peso	69	Argentine Peso to U.S. Dollar currency exchange rate after 3 years	10.5 – 15.4 (12.9)
Commodity & other:			
Embedded derivative—			
Aluminum	(55)	Market price of power for customer in Cameroon (per KWh)	$0.09 – $0.14 ($0.13)
Other	2		
Total	$(396)		

Changes in the above significant unobservable inputs that lead to a significant and unusual impact to current period earnings are disclosed to the Financial Audit Committee. For interest rate derivatives, increases (decreases) in the estimates of our own credit spreads would decrease (increase) the value of the derivatives in a liability position. For foreign currency derivatives, increases (decreases) in the estimate of the above exchange rate would increase (decrease) the value of the derivative. For commodity and other derivatives in the above table, increases (decreases) in the estimated inflation would increase (decrease) the value of those embedded derivatives, while increases (decreases) in the estimated market price for power would increase (decrease) the value of that embedded derivative.

Debt

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. 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. 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 purposes of the discounted cash flow analysis. The fair value of recourse and non-recourse debt excludes accrued interest at the valuation date. The fair value was determined using available market information as of December 31, 2012. The Company is not aware of any factors that would significantly affect the fair value amounts subsequent to December 31, 2012.

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 uses its internally developed DCF valuation models as the primary means to determine nonrecurring fair value measurements though other valuation approaches prescribed under the fair value measurement accounting guidance are also considered. Depending on the complexity of a valuation, an independent valuation firm may be engaged to assist management in the valuation process. 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 available 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 identify sale transactions of identical or similar assets. This approach is used in 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 costs. 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 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 and Reuters). 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 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 an 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 its 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.

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, 2012 and December 31, 2011:

	Fair Value			
	Total	Level 1	Level 2	Level 3
	(in millions)			
December 31, 2012				
Assets				
Available-for-sale securities	$ 681	$—	$ 681	$—
Trading securities	12	12	—	—
Derivatives	100	—	18	82
Total assets	$ 793	$ 12	$ 699	$ 82
Liabilities				
Derivatives	$ 657	$—	$ 179	$478
Total liabilities	$ 657	$—	$ 179	$478
December 31, 2011				
Assets				
Available-for-sale securities	$1,340	$ 1	$1,339	$—
Trading securities	12	12	—	—
Derivatives	120	2	52	66
Total assets	$1,472	$ 15	$1,391	$ 66
Liabilities				
Derivatives	$ 690	$—	$ 476	$214
Total liabilities	$ 690	$—	$ 476	$214

The following tables present a reconciliation of net derivative assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the year ended December 31, 2012 and 2011 (presented net by type of derivative where any foreign currency impacts are presented as part of gains (losses) in earnings or other comprehensive income as appropriate):

	Year Ended December 31, 2012				
	Interest Rate	Cross Currency	Foreign Currency	Commodity and Other	Total
			(in millions)		
Balance at January 1	$(128)	$ (18)	$ 51	$ (53)	$(148)
Total gains (losses) (realized and unrealized):					
Included in earnings	(2)	—	25	(11)	12
Included in other comprehensive income	(29)	3	—	—	(26)
Included in regulatory (assets) liabilities	—	—	—	9	9
Settlements	26	15	(3)	(2)	36
Transfers of assets (liabilities) into Level 3	(285)	—	—	—	(285)
Transfers of (assets) liabilities out of Level 3	6	—	—	—	6
Balance at December 31	$(412)	$—	$ 73	$ (57)	$(396)
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	$ (1)	$—	$ 22	$ (3)	$ 18

	Year Ended December 31, 2011				
	Interest Rate	Cross Currency	Foreign Currency	Commodity and Other	Total
			(in millions)		
Balance at January 1	$ (1)	$ 10	$ 22	$ 18	$ 49
Total gains (losses) (realized and unrealized):					
Included in earnings	—	(4)	32	(71)	(43)
Included in other comprehensive income	(13)	(37)	—	—	(50)
Included in regulatory (assets) liabilities	—	—	—	8	8
Settlements	—	13	(3)	(8)	2
Transfers of assets (liabilities) into Level 3	(117)	—	—	—	(117)
Transfers of (assets) liabilities out of Level 3	3	—	—	—	3
Balance at December 31	$(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)

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, 2012			
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Gross Loss
			(in millions)		
Assets					
Long-lived assets held and used:[1]					
Kelanitissa	$ 29	$—	$—	$ 10	$ 19
Wind projects	21	—	—	—	21
Long-lived assets held for sale:[1]					
Wind turbines	45	—	—	25	20
St. Patrick	33	—	22	—	11
Discontinued operations and held for sale businesses:					
Tisza II	105	—	14	—	91
Equity method investments[2]	205	—	155	—	50
Goodwill:					
DP&L reporting unit[3]	2,440	—	—	623	1,817

	Year Ended December 31, 2011				
	Carrying Amount	Fair Value Level 1	Fair Value Level 2	Fair Value Level 3	Gross Loss
		(in millions)			
Assets					
Long-lived assets held and used:[1]					
Kelanitissa	$ 66	$—	$—	$ 24	$ 42
Bohemia	14	—	5	—	9
Long-lived assets held for sale:[1]					
Wind turbines and deposits	161	—	45	—	116
Discontinued operations and held for sale businesses:					
Edelap, Edes and Central Dique	350	—	4	—	346
Tisza II	94	—	—	42	52
Carbon Reduction Projects	49	—	—	—	40[4]
Wind projects	22	—	—	—	22
Borsod[2]	(9)	—	—	—	—
Eastern Energy[2]	(123)	—	—	—	—
Thames[2]	(7)	—	—	—	—
Brazil Telecom business	142	—	893	—	(751)
Equity method investments:[2]					
Yangcheng	100	—	—	26	74
Goodwill:					
Chigen[3]	17	—	—	—	17

(1) See Note 21—*Asset Impairment Expense* for further information.

(2) See Note 9—*Other Non-Operating Expense* for further information.

(3) See Note 10—*Goodwill and Other Intangible Assets* for further information.

(4) 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.

The following table summarizes the significant unobservable inputs used in the Level 3 measurement of long-lived assets for the year ended December 31, 2012:

	Fair Value (in millions)	Valuation Technique	Unobservable Input	Range (Weighted Average) ($ in millions)
Long-lived assets held and used:				
Kelanitissa	$10	Discounted cash flow	Annual revenue growth	-9% to 4% (-1%)
			Annual pretax operating margin	-4% to 16% (-1%)
			Weighted average cost of capital	11.9%
Long-lived assets held for sale:				
Wind turbines	25	Market Approach	Indicative offer prices	$12 to 38 (25)
Total	$35			

Financial Instruments not Measured at Fair Value in the Condensed Consolidated Balance Sheets

The following table sets forth the carrying amount and fair value of the Company's financial assets and liabilities that are not measured at fair value in the condensed consolidated balance sheets as of December 31, 2012 and December 31, 2011, but for which fair value is disclosed. In addition, the fair value level hierarchy of such assets and liabilities is presented as of December 31, 2012:

December 31, 2012	Carrying Amount	Fair Value Total	Level 1	Level 2	Level 3
		(in millions)			
Assets					
Accounts receivable—noncurrent[1]	$ 359	$ 243	$—	$ —	$ 243
Liabilities					
Non-recourse debt	15,411	16,138	—	13,839	2,299
Recourse debt	5,962	6,628	—	6,628	—
December 31, 2011					
Assets					
Accounts receivable—noncurrent[1]	$ 376	$ 359			
Liabilities					
Non-recourse debt	15,535	15,862			
Recourse debt	6,485	6,640			

(1) These accounts receivable principally relate to amounts due from the independent system operator in Argentina and are included in "Non-current assets—Other" in the accompanying consolidated balance sheets. The fair value of these accounts receivable includes the carrying amount of value added tax which is collected from customers and paid to the government. During the year ended December 31, 2012, the significant decline in fair value of these accounts receivable was a result of the increased credit risk in Argentina. See Note 7—*Long-term Financing Receivables* for further information.

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, 2012 and 2011 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,							
	2012				2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)							
AVAILABLE-FOR-SALE:[1]								
Debt securities:								
Unsecured debentures	$—	$448	$—	$448	$—	$ 665	$—	$ 665
Certificates of deposit	—	143	—	143	—	576	—	576
Government debt securities	—	34	—	34	—	31	—	31
Subtotal	—	625	—	625	—	1,272	—	1,272
Equity securities:								
Mutual funds	—	56	—	56	—	67	—	67
Common stock	—	—	—	—	1	—	—	1
Subtotal	—	56	—	56	1	67	—	68
Total available-for-sale	—	681	—	681	1	1,339	—	1,340
TRADING:								
Equity securities:								
Mutual funds	12	—	—	12	12	—	—	12
Total trading	12	—	—	12	12	—	—	12
TOTAL	$ 12	$681	$—	$693	$ 13	$1,339	$—	$1,352
Held-to-maturity securities				3				4
Total marketable securities				$696				$1,356

(1) Amortized cost approximated fair value at December 31, 2012 and 2011, with the exception of certain common stock investments with a cost basis of $4 million carried at their fair value of $1 million at December 31, 2011.

As of December 31, 2012 and 2011, the Company did not have any Level 3 marketable securities. During 2011, the Company sold Level 3 market securities of $42 million held at the beginning of the year. As of December 31, 2012 and 2011, all available-for-sale debt securities had stated maturities of less than one year.

The following table summarizes the pre-tax gains and losses related to available-for-sale securities for the years ended December 31, 2012, 2011 and 2010. Gains and losses on the sale of investments are determined using the specific identification method. There was no other-than-temporary impairment of marketable securities recognized in earnings or other comprehensive income for the years ended December 31, 2012, 2011 and 2010.

	2012	2011	2010
	(in millions)		
Gains (losses) 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	1	2	2
(Gains) reclassified out of other comprehensive income into earnings	(1)	—	—
Gross proceeds from sales of available-for-sale securities	6,489	6,119	5,852
Gross realized gains on sales	2	3	2

6. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Volume of Activity

The following tables set forth, by type of derivative, the Company's outstanding notional under its derivatives and the weighted average remaining term as of December 31, 2012, regardless of whether the derivative instruments are in designated and qualifying cash flow hedging relationships:

	December 31, 2012					
	Current		Maximum[1]			
Interest Rate and Cross Currency[1]	Derivative Notional	Derivative Notional Translated to USD	Derivative Notional	Derivative Notional Translated to USD	Weighted Average Remaining Term	% of Debt Currently Hedged by Index[2]
	(in millions)				(in years)	
Interest Rate Derivatives:						
LIBOR (U.S. Dollar)	3,413	$3,413	4,272	$4,272	10	70%
EURIBOR (Euro)	611	807	611	807	9	64%
LIBOR (British Pound Sterling)	67	109	69	112	12	86%
Cross Currency Swaps:						
Chilean Unidad de Fomento	6	267	6	267	9	85%

(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, 2012 and the maturity of the derivative instrument, which includes forward starting derivative instruments. The interest rate and cross currency derivatives range in maturity through 2030 and 2028, respectively.

(2) The percentage of variable-rate debt currently hedged is based on the related index and excludes forecasted issuances of debt and variable-rate debt tied to other indices where the Company has no interest rate derivatives.

Foreign Currency Derivatives	December 31, 2012		
	Notional[1]	Notional Translated to USD	Weighted Average Remaining Term[2]
	(in millions)		(in years)
Foreign Currency Options and Forwards:			
Euro	98	$126	<1
Chilean Peso	52,575	108	<1
Brazilian Real	175	83	<1
Colombian Peso	89,928	49	<1
British Pound	17	27	<1
Argentine Peso	118	20	1
Embedded Foreign Currency Derivatives:			
Argentine Peso	849	173	11
Kazakhstani Tenge	1,195	8	4
Euro	2	2	11

(1) Represents contractual notionals. The notionals for options have not been probability adjusted, which generally would decrease them.

(2) Represents the remaining tenor of our foreign currency derivatives weighted by the corresponding notional. These options and forwards and these embedded derivatives range in maturity through 2014 and 2025, respectively.

Commodity Derivatives	December 31, 2012	
	Notional	Weighted Average Remaining Term[1]
	(in millions)	(in years)
Aluminum (MWh)[2]	14	7
Power (MWh)	4	3

(1) Represents the remaining tenor of our commodity and embedded derivatives weighted by the corresponding volume. These derivatives range in maturity through 2019.

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

Accounting and Reporting

Fair Value Hierarchy & Hedging Designation

The following tables set forth the fair value of the Company's types of derivative instruments as of December 31, 2012 and 2011 by level within the fair value hierarchy then by whether or not they are designated hedging instruments.

	December 31, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)				(in millions)			
Assets								
Interest rate derivatives	$—	$ 2	$—	$ 2	$—	$—	$—	$—
Cross currency derivatives	—	6	—	6	—	—	1	1
Foreign currency derivatives	—	2	79	81	—	27	62	89
Commodity and other derivatives	—	8	3	11	2	25	3	30
Total assets	$—	18	$ 82	$100	$ 2	$ 52	$ 66	$120
Liabilities								
Interest rate derivatives	$—	$153	$412	$565	$—	$431	$128	$559
Cross currency derivatives	—	6	—	6	—	—	19	19
Foreign currency derivatives	—	7	7	14	—	15	11	26
Commodity and other derivatives	—	13	59	72	—	30	56	86
Total liabilities	$—	$179	$478	$657	$—	$476	$214	$690

	December 31, 2012			December 31, 2011		
	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						
Interest rate derivatives	$—	$ 2	$ 2	$—	$—	$—
Cross currency derivatives	6	—	6	1	—	1
Foreign currency derivatives	—	81	81	13	76	89
Commodity and other derivatives	2	9	11	2	28	30
Total assets	$ 8	$ 92	$100	$ 16	$104	$120
Liabilities						
Interest rate derivatives	$544	$ 21	$565	$535	$ 24	$559
Cross currency derivatives	6	—	6	19	—	19
Foreign currency derivatives	7	7	14	1	25	26
Commodity and other derivatives	8	64	72	3	83	86
Total liabilities	$565	$ 92	$657	$558	$132	$690

As of December 31, 2012 and 2011, these tables include current assets of $14 million and $49 million, respectively, noncurrent assets of $86 million and $71 million, respectively, current liabilities of $186 million and $153 million, respectively, and noncurrent liabilities of $471 million and $537 million, respectively. These tables do not include the following balances that had been, but no longer need to be, accounted for as derivatives at fair value that are to be amortized to earnings over the remaining term of the associated PPA: $186 million and

$163 million of assets as of December 31, 2012 and 2011, respectively and $191 million of liabilities as of December 31, 2012. The amortization is included in the table below under "Not Designated for Hedge Accounting".

Effective Portion of Cash Flow Hedges

The following table sets forth the pre-tax gains (losses) recognized in AOCL and earnings related to the effective portion of derivative instruments in qualifying cash flow hedging relationships (including amounts that were reclassified from AOCL to interest expense related to interest rate derivative instruments that previously, but no longer, qualify for cash flow hedge accounting), as defined in the accounting standards for derivatives and hedging, for the years ended December 31, 2012, 2011 and 2010:

	Gains (Losses) Recognized in AOCL			Consolidated Statement of Operations	Gains (Losses) Reclassified from AOCL into Earnings		
	2012	2011	2010		2012	2011	2010
	(in millions)				(in millions)		
Interest rate derivatives	$(175)	$(475)	$(288)	Interest expense	$(135)	$(125)	$(110)
				Non-regulated cost of sales	(6)	(3)	(3)
				Net equity in earnings of affiliates	(7)	(4)	(1)
				Income (loss) from discontinued operations	—	—	(113)
				Asset impairment expense	(6)	—	—
				Gain on sale of investments	(96)	—	—
Cross currency derivatives	4	(36)	15	Interest expense	(12)	(10)	(4)
				Foreign currency transaction gains (losses)	26	(16)	25
Foreign currency derivatives	10	24	(16)	Foreign currency transaction gains (losses)	5	1	(8)
Commodity and other derivatives	(8)	—	(9)	Non-regulated revenue	(2)	—	1
				Non-regulated cost of sales	—	(2)	—
				Income (loss) from discontinued operations	—	—	10
Total	$(169)	$(487)	$(298)		$(233)	$(159)	$(203)

For the years ended December 31, 2012, 2011 and 2010, the above table includes pre-tax gains (losses) of $(10) million, $0 million, and $(1) million, respectively, that 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 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, 2012 is $(110) million for interest rate hedges, $9 million for cross currency swaps, $(3) million for foreign currency hedges, and $(7) million for commodity and other hedges.

Ineffective Portion of Cash Flow Hedges

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, 2012, 2011 and 2010:

	Classification in Consolidated Statement of Operations	Gains (Losses) Recognized in Earnings		
		2012	2011	2010
			(in millions)	
Interest rate derivatives	Interest expense	$(2)	$ (6)	$ (15)
	Net equity in earnings of affiliates	(1)	(2)	—
Cross currency derivatives	Interest expense	(1)	(4)	5
Total		$(4)	$(12)	$ (10)

Not Designated for Hedge Accounting

The following table sets forth the gains (losses) recognized in earnings related to derivative instruments not designated as hedging instruments under the accounting standards for derivatives and hedging, for the years ended December 31, 2012, 2011 and 2010:

	Classification in Consolidated Statement of Operations	Gains (Losses) Recognized in Earnings		
		2012	2011	2010
			(in millions)	
Interest rate derivatives	Interest expense	$ (5)	$ (4)	$ (9)
Foreign currency derivatives	Foreign currency transaction gains (losses)	(141)	60	(35)
	Net equity in earnings of affiliates	—	—	(2)
Commodity and other derivatives	Non-regulated revenue	20	(63)	29
	Regulated revenue	(10)	1	—
	Non-regulated cost of sales	2	(9)	5
	Regulated cost of sales	(15)	(5)	—
Total		$(149)	$ (20)	$ (12)

Credit Risk-Related Contingent Features

Our generation business in Chile has cross currency swap agreements that 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 mark-to-market value of the derivatives exceeds the unsecured thresholds established in the agreements. If Gener's credit rating were to fall below the minimum threshold, the counterparties can demand immediate collateralization of the entire mark-to-market loss of the swaps (fair value excluding credit valuation adjustments), which was $2 million and $18 million at December 31, 2012 and 2011, respectively.

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 (fair value excluding credit valuation adjustments), which was $13 million and $28 million as of December 31, 2012 and 2011, respectively. As of December 31, 2012 and 2011, DPL had posted $5 million and $16 million, respectively, of cash collateral directly with third parties or in a broker margin account and DPL held $0 million and $3 million, respectively, of cash collateral that it received from counterparties to its derivative instruments that were in an asset position.

7. LONG-TERM FINANCING RECEIVABLES

Long-term financing receivables represent receivables from certain Latin American governmental bodies, primarily in Argentina, that have contractual maturities of greater than one year. In Argentina, as a result of energy market reforms which began in 2004, and consistent with contractual arrangements, the Company converted certain accounts receivable into long-term financing receivables. These receivables accrue interest and are collected in monthly installments over 10 years once the related plant begins operations. In addition, the Company also receives an ownership interest in these newly-built plants once the receivables have been fully repaid. Collection of the Argentina financing receivables is subject to various business risks and uncertainties including timely payment of principal and interest, completion and operation of power plants which provide for payments of the long-term receivables, regulatory changes that could impact the timing and amount of collections and economic conditions in Argentina. The Company periodically analyzes each of these factors and assesses collectability of the related accounts receivable. The Company's collection estimates are based on assumptions that it believes to be reasonable but are also inherently uncertain. Actual future cash flows could differ from these estimates. The decrease in the long-term financing receivables from December 31, 2011 is primarily related to the impact of foreign currency translation. The receivables are included in "Noncurrent assets —other" on the Consolidated Balance Sheets. The following table sets forth the breakdown of financing receivables by country as of December 31, 2012 and 2011:

	2012	2011
	(in millions)	
Argentina[1]	$196	$232
Dominican Republic	35	49
Brazil	8	14
Total long-term financing receivables	$239	$295

(1) Excludes noncurrent receivables of $120 million and $82 million, respectively, as of December 31, 2012 and 2011, which have not been converted into long-term financing receivables and currently have no due date.

8. 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, 2012 and 2011.

Affiliate	Country	December 31, 2012	2011	2012	2011
		Carrying Value (in millions)		Ownership Interest %	
AES Solar Holding Co[1]	Various	$ 307	$ 324	50%	50%
Barry[2]	United Kingdom	—	—	100%	100%
Cartagena[3]	Spain	—	N/A	14%	N/A
CET[2]	Brazil	13	14	72%	72%
Chigen affiliates [4]	China	2	30	35%	25%
China Wind[5]	China	—	75	0%	49%
Elsta	Netherlands	219	197	50%	50%
Entek[6]	Turkey	234	121	50%	50%
Guacolda	Chile	196	186	35%	35%
IC Ictas Energy Group[6]	Turkey	—	161	0%	51%
InnoVent[2],[7]	France	—	32	0%	40%
JHRH[8]	China	—	59	0%	49%
OPGC	India	199	203	49%	49%
Trinidad Generation Unlimited[2]	Trinidad	24	19	10%	10%
Other affiliates	Various	2	1		
Total investments in and advances to affiliates		$1,196	$1,422		

(1) Represent our investments in AES Solar Energy Ltd in Europe, AES Solar Power LLC in the United States and AES Solar Power, PR, LLC in Puerto Rico.

(2) Represent VIEs in which the Company holds a variable interest, but is not the primary beneficiary.

(3) The Company sold 80% of its interest in AES Energia Cartagena S.R.L. during 2012 resulting in the deconsolidation of this entity. Refer to Note 24—*Acquisitions and Dispositions* for further information.

(4) Represent our investments in Chengdu AES Kaihua Gas Turbine Company Ltd. and Yangcheng International Power Generating Co. Ltd. The Company sold its interest in the Yangcheng affiliates during 2012. Refer to Note 24—*Acquisitions and Dispositions* for further information.

(5) 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. The Company sold its interest in the affiliates during 2012. Refer to Note 24—*Acquisitions and Dispositions* for further information.

(6) IC Ictas Energy Group joint venture was dissolved during 2012. See the Entek description below.

(7) The Company sold its interest in InnoVent during 2012. Refer to Note 9—*Other Non-Operating Expense* for further information.

(8) The Company completed the sale of its interest in JHRH in the fourth quarter of 2012. Refer to Note 9—*Other Non-Operating Expense* for further information.

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, 2012 and 2011, other long-term liabilities included $55 million and $52 million, respectively, related to this debt agreement.

AES Entek Elektrik Üretimi A.Ş. ("Entek")— Entek, a joint venture with Koc Holding, owns and operates gas-fired and hydroelectric generation facilities in Turkey with an aggregate capacity of 378 MW and is also engaged in an energy trading business. During the fourth quarter of 2012, AES entered into an agreement to dissolve a separate joint venture in Turkey with IC Ictas Energy Group. Under the agreement, AES received net proceeds of $10 million and a 100% interest in three hydroelectric plants with an aggregate generation capacity of 62 MW from IC Ictas Energy Group. The Company recognized a pretax gain of $1 million on the dissolution. Thereafter, the Company sold these hydropower plants to Entek and received net proceeds of $82 million. Both transactions closed in the fourth quarter of 2012.

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 has four gas turbines, which commenced commercial operations in 2011 and 2012.

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,	**2012**	**2011**	**2010**	**2012**	**2011**	**2010**
	(in millions)			(in millions)		
Revenue	$1,868	$1,668	$1,341	$106	$ 24	$20
Gross margin	355	258	207	26	24	18
Net income (loss)	146	(5)	100	(5)	(5)	7

December 31,	**2012**	**2011**	**2012**	**2011**
	(in millions)		(in millions)	
Current assets	$1,097	$1,182	$ 2	$ 58
Noncurrent assets	5,253	4,298	38	519
Current liabilities	680	899	55	109
Noncurrent liabilities	2,899	1,720	20	269
Noncontrolling interests	(228)	(240)	—	—
Stockholders' equity	2,999	3,101	(35)	199

At December 31, 2012, accumulated deficit included $150 million related to the undistributed earnings of the Company's 50%-or-less owned affiliates. Distributions received from these affiliates were $22 million, $36 million, and $49 million for the years ended December 31, 2012, 2011, and 2010, respectively. As of December 31, 2012, the aggregate carrying amount of our investments in equity affiliates exceeded the underlying equity in their net assets by $37 million.

9. OTHER NON-OPERATING EXPENSE

Other non-operating expense for the years ended December 31, 2012, 2011 and 2010 consisted of:

	Years Ended December 31,		
	2012	2011	2010
		(in millions)	
China generation and wind	$32	$ 79	$—
InnoVent	17	—	—
Other	1	3	7
Total other-non operating expense	$50	$ 82	$ 7

2012

China—During the first quarter of 2012, the Company concluded it was more likely than not that it would sell its interests in certain joint ventures in China before the end of their terms. These investments include coal-fired, hydroelectric and wind generation facilities accounted for under the equity method of accounting. This conclusion was considered an impairment indicator. In measuring the other-than-temporary impairment, the carrying value of $165 million of these investments was compared to their fair value of $133 million resulting in an other-than-temporary impairment expense of $32 million. The Company signed two separate sale agreements for the sale of these investments, which were closed in the third and fourth quarters of 2012. See Note 24—*Acquisitions and Dispositions* for further information.

InnoVent—During the first quarter of 2012, the Company concluded it was more likely than not that it would sell its interest in InnoVent S.A.S. ("InnoVent"), an equity method investment in France with wind generation projects totaling 75 MW. InnoVent had a carrying value of $36 million which exceeded its fair value of $19 million, resulting in an other-than-temporary impairment expense of $17 million. The sale transaction was completed on June 28, 2012.

2011

China— During the third quarter of 2011, the Company recognized other-than-temporary-impairment on its 25% investment in Yangcheng, a 2100 MW coal-fired plant in China. During the nine months ended September 30, 2011, continually increasing coal prices in China reduced operating margins of coal generation facilities with no corresponding increase in tariffs. Further, under the Yangcheng venture agreement in effect at this time, AES was to surrender its equity interest to the venture partners in 2016 without additional compensation. 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 determined under the discounted cash flow analysis, and the difference was recognized as other non-operating expense.

2010

Other—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 not to pursue its investment in a project to generate environmental offset credits and recognized the other-than-temporary impairment.

10. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The following table summarizes the changes in the carrying amount of goodwill, by segment for the years ended December 31, 2012 and 2011.

	US - Generation	US - Utilities	Andes - Generation	MCAC - Generation	EMEA - Generation	Asia - Generation	Corporate and Other	Total
Balance as of December 31, 2010								
Goodwill	$106	$ —	$899	$ 16	$ 180	$ 80	$133	$ 1,414
Accumulated impairment losses	(21)	—	—	—	(122)	—	—	(143)
Net balance	85	—	899	16	58	80	133	1,271
Impairment losses	—	—	—	—	—	(17)	—	(17)
Goodwill acquired during the year	—	2,576	—	—	—	—	—	2,576
Foreign currency translation and other	(10)	—	—	—	—	—	—	(10)
Balance as of December 31, 2011								
Goodwill	96	2,576	899	16	180	80	133	3,980
Accumulated impairment losses	(21)	—	—	—	(122)	(17)	—	(160)
Net balance	75	2,576	899	16	58	63	133	3,820
Impairment losses	—	(1,817)	—	—	—	—	—	(1,817)
Goodwill associated with the sale of a business	—	—	—	—	—	—(1)	—	—
Foreign currency translation and other	(9)	—	—	—	—	5	—	(4)
Balance as of December 31, 2012								
Goodwill	87	2,576	899	16	180	68	133	3,959
Accumulated impairment losses	(21)	(1,817)	—	—	(122)	—	—	(1,960)
Net balance	$ 66	$ 759	$899	$ 16	$ 58	$ 68	$133	$ 1,999

(1) Both the gross carrying amount and the accumulated impairment losses of the Asia generation segment have been reduced by $17 million with no impact on the net carrying amount for the segment. This relates to Chigen, which had fully impaired goodwill of $17 million and was sold during the year.

DPL—In connection with its acquisition of DPL, the Company recognized goodwill of approximately $2.6 billion, which was allocated between the two reporting units identified during the purchase price allocation: The Dayton Power and Light Company ("DP&L", DPL's regulated utility in Ohio) and certain related entities, and

DPL Energy Resources, Inc. ("DPLER", DPL's wholly-owned competitive retail electric service provider). Of the total goodwill, approximately $2.4 billion was allocated to DP&L and the remainder was allocated to DPLER.

On October 5, 2012, DP&L filed for approval an Electric Security Plan ("ESP") with the Public Utility Commission of Ohio ("PUCO"). The plan was re-filed on December 31, 2012 to correct for certain projected costs. Within the ESP filing, DP&L agreed to request a separation of its generation assets from its transmission and distribution assets in recognition that a restructuring of DP&L operations will be necessary, in compliance with Ohio law. Also, during 2012, North American natural gas prices fell significantly from the previous year exerting downward pressure on wholesale electricity prices in the Ohio power market. Falling power prices compressed wholesale margins at DP&L. Furthermore, these lower power prices have led to increased customer switching from DP&L to other competitive retail electric service ("CRES") providers, including DPLER, who are offering retail prices lower than DP&L's current standard service offer. Also, several municipalities in DP&L's service territory have passed ordinances allowing them to become government aggregators and some municipalities have contracted with CRES providers to provide generation service to the customers located within the municipal boundaries, further contributing to the switching trend. CRES providers have also become more active in DP&L's service territory. In September 2012, management revised its cash flow forecasts based on these new developments and forecasted lower profitability and operating cash flows than previously prepared forecasts. These new developments have reduced DP&L's forecasted profitability, operating cash flows, liquidity and may impact DPL and DP&L's ability to access the capital markets and maintain their current credit ratings in the future. Collectively, in the third quarter of 2012, these events were considered an interim impairment indicator for goodwill at the DP&L reporting unit. There were no interim impairment indicators identified for the goodwill at DPLER.

The Company performed an interim impairment test for the $2.4 billion of goodwill at the DP&L reporting unit level. In the preliminary Step 1 of the goodwill impairment test, the fair value of the reporting unit was determined under the income approach using a discounted cash flow valuation model. The material assumptions included within the discounted cash flow valuation model were customer switching and aggregation trends, capacity price curves, energy price curves, amount of the non-bypassable charge, commodity price curves, dispatching, transition period for the conversion to a wholesale competitive bidding structure, amount of the standard service offer charge, valuation of regulatory assets and liabilities, discount rates and deferred income taxes. The reporting unit failed the preliminary Step 1 and a preliminary Step 2 of the goodwill impairment test was performed. Further refinements to these assumptions were performed in the fourth quarter of 2012 as part of the finalization of Step 1 and Step 2 tests. During the year ended December 31, 2012, the Company recognized goodwill impairment expense of $1.82 billion at the DP&L reporting unit. DPL is reported in the US Utilities segment. The goodwill associated with the DPL acquisition is not deductible for tax purposes. Accordingly, there is no cash tax or financial statement tax benefit related to the impairment. The pretax impairment impacted the Company's effective tax rate for the year ended December 31, 2012, which was 225%.

Chigen—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 of 2011.

Deepwater—During the third quarter of 2010, Deepwater, our petcoke-fired merchant generation facility in Texas, reported in the US 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 of 2010.

Intangible Assets

The following tables summarize the balances comprising other intangible assets in the accompanying Consolidated Balance Sheets as of December 31, 2012 and 2011:

	December 31, 2012			December 31, 2011		
	Gross Balance	Accumulated Amortization (in millions)	Net Balance	Gross Balance	Accumulated Amortization (in millions)	Net Balance
Subject to Amortization						
Project development rights[1]	$102	$ (1)	$101	$109	$ (1)	$108
Sales concessions	194	(101)	93	199	(95)	104
Contractual payment rights[2]	72	(23)	49	69	(13)	56
Management rights	40	(14)	26	39	(13)	26
Emission allowances	5	—	5	14	—	14
Electric security plan	87	(87)	—	87	(9)	78
Contracts	44	(20)	24	44	(17)	27
Customer contracts and relationships	66	(26)	40	66	(7)	59
Other[3]	16	(4)	12	18	(9)	9
Subtotal	626	(276)	350	645	(164)	481
Indefinite-Lived Intangible Assets						
Land use rights	50	—	50	52	—	52
Water rights	18	—	18	5	—	5
Trademark/Trade name	6	—	6	5	—	5
Other	5	—	5	2	—	2
Subtotal	79	—	79	64	—	64
Total	$705	$(276)	$429	$709	$(164)	$545

(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 operations in Poland and the U.K.

(2) Represent legal rights to receive system reliability payments from the regulator.

(3) Includes renewable energy credits, land use rights and various other intangible assets none of which is individually significant.

The following table summarizes, by category, intangible assets acquired during the years ended December 31, 2012 and 2011:

	December 31, 2012			
	Amount	Subject to Amortization/ Indefinite-Lived	Weighted Average Amortization Period	Amortization Method
	(in millions)		(in years)	
Renewable energy certificates	$ 5	Subject to amortization	Various	As utilized
Water rights	13	Indefinite-lived	N/A	N/A
Other	1	Indefinite-lived	N/A	N/A
Total	$19			

	December 31, 2011			
	Amount	Subject to Amortization/ Indefinite-Lived	Weighted Average Amortization Period	Amortization Method
	(in millions)		(in years)	
Electric security plan[1] [2]	$ 87	Subject to amortization	1	Straight line
Customer relationships[1] [3]	32	Subject to amortization	12	Other
Customer contracts[1] [4]	28	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	$156			

(1) Represents intangible assets arising from the acquisition of DPL. See Note 24—*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 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 24—*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) Trademark/trade name represents 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, by intangible asset category, for 2013 through 2017:

	Estimated amortization expense				
	2013	2014	2015	2016	2017
	(in millions)				
Customer relationships & contracts	$11	$ 5	$ 4	$ 3	$ 3
Sales concessions	8	8	8	8	8
Contractual payment rights	9	9	9	3	3
All other	4	3	3	3	2
Total	$32	$25	$24	$17	$16

Intangible asset amortization expense was $119 million, $36 million and $14 million for the years ended December 31, 2012, 2011 and 2010, respectively.

11. REGULATORY ASSETS AND 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, 2012	December 31, 2011	Recovery/Refund Period
	(in millions)		
REGULATORY ASSETS			
Current regulatory assets:			
Brazil tariff recoveries:[1]			
Energy purchases	$ 189	$ 79	Over tariff reset period
Transmission costs, regulatory fees and other	78	185	Over tariff reset period
El Salvador tariff recoveries[2]	115	108	Over tariff reset period
Other[3]	26	19	Various
Total current regulatory assets	408	391	
Noncurrent regulatory assets:			
Defined benefit pension obligations at IPL and DPL[4][5]	430	399	Various
Income taxes recoverable from customers[4][6]	81	76	Various
Brazil tariff recoveries:[1]			
Energy purchases	97	84	Over tariff reset period
Transmission costs, regulatory fees and other	59	86	Over tariff reset period
Deferred Midwest ISO costs[7]	89	80	To be determined
Other[3]	115	122	Various
Total noncurrent regulatory assets	871	847	
TOTAL REGULATORY ASSETS	$1,279	$1,238	
REGULATORY LIABILITIES			
Current regulatory liabilities:			
Brazil tariff reset adjustment[8]	$ 89	$ 190	Three years
Efficiency program costs[9]	32	29	Over tariff reset period
Brazil tariff recoveries:[1]			
Energy purchases	171	305	Over tariff reset period
Transmission costs, regulatory fees and other	55	172	Over tariff reset period
Other[10]	41	37	Various
Total current regulatory liabilities	388	733	
Noncurrent regulatory liabilities:			
Brazil tariff reset adjustment[8]	445	—	Three years
Asset retirement obligations[11]	560	649	Over life of assets
Brazil special obligations[12]	463	422	To be determined
Brazil tariff recoveries:[1]			
Energy purchases	46	76	Over tariff reset period
Transmission costs, regulatory fees and other	42	64	Over tariff reset period
Efficiency program costs[9]	17	44	Over tariff reset period
Other[10]	129	24	Various
Total noncurrent regulatory liabilities	1,702	1,279	
TOTAL REGULATORY LIABILITIES	$2,090	$2,012	

(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 $19 million and $12 million, as of December 31, 2012 and 2011, respectively. Other noncurrent regulatory assets that did not earn a rate of return were $60 million and $37 million, as of December 31, 2012 and 2011, 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) Probability 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 2012, the Brazilian energy regulator (the "Regulator") approved 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 retroactive to July 2011 and will be applied to customers' invoices from July 2012 to June 2015. From July 2011 through June 2012, Eletropaulo invoiced customers under the then existing tariff rate, as required by the Regulator. As the new tariff rate is lower than the pre-existing tariff rate, Eletropaulo is required to reduce customer tariffs for this difference over the next three years. Accordingly, from July 2011 through June 2012, Eletropaulo recognized a regulatory liability for such estimated future refunds, which was subsequently adjusted as of June 30, 2012 upon the finalization of the new tariff with the Regulator. As of December 31, 2012, Eletropaulo had recorded a current and noncurrent regulatory liability of $89 million and $445 million, respectively.

(9) Amounts received for costs expected to be incurred to improve the efficiency of our plants in Brazil as part of the IRT.

(10) Other current and noncurrent regulatory liabilities primarily consist of liabilities owed to 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 noncurrent liabilities," respectively, in the accompanying Consolidated Balance Sheets.

The following table summarizes regulatory assets and liabilities by segment as of December 31, 2012 and 2011:

	December 31,			
	2012		2011	
	Regulatory Assets	Regulatory Liabilities	Regulatory Assets	Regulatory Liabilities
	(in millions)			
Brazil Utilities	$ 427	$1,390	$ 438	$1,333
US Utilities	737	700	692	679
Corporate and Other	115	—	108	—
Total	$1,279	$2,090	$1,238	$2,012

12. DEBT

Non-Recourse Debt

The following table summarizes the carrying amount and terms of non-recourse debt as of December 31, 2012 and 2011:

NON-RECOURSE DEBT	Weighted Average Interest Rate	Maturity	December 31, 2012	December 31, 2011
			(in millions)	
VARIABLE RATE:(1)				
Bank loans	3.44%	2013 – 2030	$ 3,532	$ 3,430
Notes and bonds	8.08%	2013 – 2040	1,887	2,178
Debt to (or guaranteed by) multilateral, export credit agencies or development banks(2)	3.43%	2013 – 2027	2,129	1,989
Other	5.33%	2013 – 2042	357	321
FIXED RATE:				
Bank loans	8.76%	2013 – 2023	231	412
Notes and bonds	6.36%	2013 – 2061	6,448	6,487
Debt to (or guaranteed by) multilateral, export credit agencies or development banks(2)	6.51%	2013 – 2027	616	513
Other	8.16%	2013 – 2039	211	205
SUBTOTAL			$15,411(3)	$15,535(3)
Less: Current maturities			(2,843)	(2,123)
TOTAL			$12,568	$13,412

(1) The interest rate on variable rate debt represents the total of a variable component that is based on changes in an interest rate index and of a fixed component. The Company has interest rate swaps and option agreements in an aggregate notional principal amount of approximately $3.6 billion on non-recourse debt outstanding at December 31, 2012. These agreements economically fix the variable component of the interest rates on the portion of the variable-rate debt being hedged so that the total interest rate on that debt has been fixed at rates ranging from approximately 4.33% to 8.70% and 6.53% to 8.75% for swaps and options, respectively. These agreements expire at various dates from 2013 through 2030.

(2) Multilateral loans include loans funded and guaranteed by bilaterals, multilaterals, development banks and other similar institutions.

(3) Non-recourse debt of $1.3 billion as of December 31, 2011 was excluded from non-recourse debt and included in current and noncurrent liabilities of held for sale and discontinued businesses in the accompanying Consolidated Balance Sheets. There were no amounts excluded in 2012.

Non-recourse debt as of December 31, 2012 is scheduled to reach maturity as set forth in the table below:

December 31,	Annual Maturities
	(in millions)
2013	$ 2,843
2014	1,416
2015	765
2016	2,374
2017	699
Thereafter	7,314
Total non-recourse debt	$15,411

As of December 31, 2012, AES subsidiaries with facilities under construction had a total of approximately $1.2 billion of committed but unused credit facilities available to fund construction and other related costs. Excluding these facilities under construction, AES subsidiaries had approximately $1.6 billion in a number of available but unused committed credit lines to support their working capital, debt service reserves and other business needs. These credit lines can be used for borrowings, letters of credit, or a combination of these uses. The weighted average interest rate on borrowings from such revolving credit facilities was 13.53% at December 31, 2012.

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.

As of December 31, 2012 and 2011, approximately $612 million and $594 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 $1.7 billion at December 31, 2012.

The following table summarizes the Company's subsidiary non-recourse debt in default or accelerated as of December 31, 2012 and is included in the current portion of non-recourse debt unless otherwise indicated:

Subsidiary	Primary Nature of Default	December 31, 2012	
		Default	Net Assets
		(in millions)	
Maritza[(1)]	Covenant	$ 872	$578
Sonel	Covenant	294	379
Kavarna	Covenant	209	79
Saurashtra	Covenant	25	15
Total		$1,400	

(1) In January 2013, Maritza and its lenders reached an agreement in principle to waive the defaults subject to a number of conditions, many of which are not completely within our control.

The defaults are not payment defaults, but are instead technical defaults triggered by failure to comply with other covenants and/or other conditions such as (but not limited to) failure to meet information covenants, complete construction or other milestones in an allocated time, meet certain minimum or maximum financial ratios, or other requirements contained in the non-recourse debt documents of the Company.

In addition, in the event that there is a default, bankruptcy or maturity acceleration at a subsidiary that meets the applicable definition of materiality under the corporate debt agreements of The AES Corporation, there could be a cross-default to the Company's recourse debt. At December 31, 2012 none of the defaults listed above results in a cross-default under the recourse debt of the Company.

RECOURSE DEBT

The following table summarizes the carrying amount and terms of recourse debt of the Company as of December 31, 2012 and 2011:

RECOURSE DEBT	Interest Rate	Final Maturity	December 31, 2012	December 31, 2011
			(in millions)	
Senior Unsecured Note	7.75%	2014	500	500
Revolving Loan under Senior Secured Credit Facility	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	807	1,042
Senior Unsecured Note	8.00%	2020	625	625
Senior Unsecured Note	7.38%	2021	1,000	1,000
Term Convertible Trust Securities	6.75%	2029	517	517
Unamortized discounts			(22)	(29)
SUBTOTAL			$5,962	$6,485
Less: Current maturities			(11)	(305)
Total			$5,951	$6,180

The table below summarizes the principal amounts due, net of unamortized discounts, under our recourse debt for the next five years and thereafter:

December 31,	Net Principal Amounts Due
	(in millions)
2013	$ 11
2014	510
2015	511
2016	527
2017	1,510
Thereafter	2,893
Total recourse debt	$5,962

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, and AES Warrior Run. 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 of 7.5× at December 31, 2012.

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 and a VIE, issued approximately 10.35 million of $50 par value Term Convertible Preferred Securities ("TECONS") with a semi-annual coupon payment of $3.375 for total proceeds of $517 million and concurrently purchased $517 million of 6.75% Junior Subordinated Convertible Debentures due 2029 (the "6.75% Debentures") issued by AES. The Company consolidates AES Trust III in its consolidated financial statements and classifies the TECONS as recourse debt on its Consolidated Balance Sheet. The Company's obligations under the 6.75% Debentures and other relevant trust agreements, in aggregate, constitute a full and unconditional guarantee by the Company of the TECON Trusts' obligations. As of December 31, 2012 and 2011, the sole assets of AES Trust III are the 6.75% Debentures.

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.

13. COMMITMENTS

LEASES—The Company and its subsidiaries enter into long-term non-cancelable lease arrangements which, for accounting purposes, are classified as either operating lease or capital lease. Operating leases primarily include certain transmission lines, office rental and site leases. Operating lease rental expense for the years ended December 31, 2012, 2011 and 2010 was $58 million, $63 million and $56 million, respectively. Capital leases primarily include transmission lines at our subsidiaries in Brazil, vehicles, and office and other operating equipment. Capital leases are recognized in Property, Plant and Equipment within "Electric generation and distribution assets." The gross value of the capital lease assets as of December 31, 2012 and 2011 was $94 million and $95 million, respectively. The table below sets forth the future minimum lease payments under operating and capital leases together with the present value of the net minimum lease payments under capital leases as of December 31, 2012 for 2013 through 2017 and thereafter:

	Future Commitments for	
December 31,	Capital Leases	Operating Leases
	(in millions)	
2013	$ 12	$ 53
2014	12	51
2015	11	48
2016	11	47
2017	11	47
Thereafter	160	517
Total	217	$763
Less: Imputed interest	138	
Present value of total minimum lease payments	$ 79	

CONTRACTS—The Company's operating subsidiaries enter into long-term contracts for construction projects, maintenance and service, transmission of electricity, operations services and purchase of electricity and fuel. In general, these contracts are subject to variable quantities or prices and are terminable in limited circumstances only. Electricity purchase contracts primarily include energy auction agreements at our Brazil subsidiaries with extended terms from 2013 through 2028. The table below sets forth the future minimum commitments under these contracts as of December 31, 2012 for 2013 through 2017 and thereafter. Actual purchases under these contracts for the years ended December 31, 2012, 2011 and 2010 are also presented:

	Electricity Purchase Contracts	Fuel Purchase Contracts	Other Purchase Contracts
Actual purchases during the year ended December 31,		(in millions)	
2010	$ 2,422	$1,686	$ 1,652
2011	2,463	1,577	1,767
2012	2,819	1,860	1,701
Future commitments for the year ending December 31,			
2013	$ 2,599	$1,555	$ 1,976
2014	3,008	998	1,743
2015	2,952	555	1,629
2016	2,971	428	1,202
2017	2,351	416	1,093
Thereafter	25,001	4,618	11,153
Total	$38,882	$8,570	$18,796

14. CONTINGENCIES

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 14 years.

The following table summarizes the Parent Company's contingent contractual obligations as of December 31, 2012. 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	$568	19	<$1 - $237
Cash collateralized letters of credit	215	9	<$1 - $189
Letters of credit under the senior secured credit facility	5	6	<$1 -$2
Total	$788	34	

As of December 31, 2012, the Company had $3 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 2013. 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 2012, the Company paid letter of credit fees ranging from 0.250% to 3.250% per annum on the outstanding amounts of letters of credit.

Environmental

The Company periodically reviews its obligations as they relate to compliance with environmental laws, including site restoration and remediation. As of December 31, 2012, the Company had recorded liabilities of $14 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, 2012.

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 $321 million and $363 million as of December 31, 2012 and 2011, 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, 2012. 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 $881 million to $1.6 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.

15. 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. For the year ended December 31, 2012, the Company's contributions to the Plan were approximately $21 million, and for the years ended December 31, 2011 and 2010, contributions were $22 million per year.

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 31 active defined benefit plans as of December 31, 2012, 5 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, 2012 and 2011:

	December 31,			
	2012		2011	
	U.S.	Foreign	U.S.	Foreign
	(in millions)			
CHANGE IN PROJECTED BENEFIT OBLIGATION:				
Benefit obligation as of January 1	$1,044	$ 5,789	$ 608	$ 5,986
Service cost	14	19	8	19
Interest cost	48	481	33	564
Employee contributions	—	5	—	5
Plan amendments	7	1	—	—
Plan curtailments	—	—	—	5
Plan settlements	(1)	(2)	—	—
Benefits paid	(51)	(408)	(30)	(465)
Business combinations	—	—	365	—
Assumption of a plan due to the resolution of bankruptcy proceedings[(1)]	51	—	—	—
Actuarial loss	98	1,339	60	371
Effect of foreign currency exchange rate change	—	(415)	—	(696)
Benefit obligation as of December 31	$1,210	$ 6,809	$1,044	$ 5,789
CHANGE IN PLAN ASSETS:				
Fair value of plan assets as of January 1	$ 762	$ 4,400	$ 413	$ 4,730
Actual return on plan assets	97	888	6	486
Employer contributions	49	155	37	175
Employee contributions	—	5	—	5
Plan settlements	(1)	(2)	—	—
Benefits paid	(51)	(408)	(30)	(465)
Business combinations	—	—	336	—
Assumption of a plan due to the resolution of bankruptcy proceedings[(1)]	27	—	—	—
Effect of foreign currency exchange rate change	—	(326)	—	(531)
Fair value of plan assets as of December 31	$ 883	$ 4,712	$ 762	$ 4,400
RECONCILIATION OF FUNDED STATUS				
Funded status as of December 31	$ (327)	$(2,097)	$ (282)	$(1,389)

(1) The Company assumed the pension plan for AES Eastern Energy on December 28, 2012 as part of the settlement of the bankruptcy proceedings. See Note 23—*Discontinued Operations and Held for Sale Businesses* for further information.

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, 2012 and 2011:

	December 31,			
	2012		2011	
	U.S.	Foreign	U.S.	Foreign
	(in millions)			
AMOUNTS RECOGNIZED ON THE CONSOLIDATED BALANCE SHEETS				
Noncurrent assets	$ —	$ —	$ —	$ 20
Accrued benefit liability—current	—	(6)	(1)	(4)
Accrued benefit liability—noncurrent	(327)	(2,091)	(281)	(1,405)
Net amount recognized at end of year	$(327)	$(2,097)	$(282)	$(1,389)

The following table summarizes the Company's accumulated benefit obligation, both domestic and foreign, as of December 31, 2012 and 2011:

	December 31,			
	2012		2011	
	U.S.	Foreign	U.S.	Foreign
	(in millions)			
Accumulated Benefit Obligation	$1,180	$6,695	$1,020	$5,724
Information for pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	$1,210	$6,438	$1,044	$5,478
Accumulated benefit obligation	1,180	6,352	1,020	5,423
Fair value of plan assets	883	4,360	762	4,072
Information for pension plans with a projected benefit obligation in excess of plan assets:				
Projected benefit obligation	$1,210	$6,809[1]	$1,044	$5,492
Fair value of plan assets	883	4,712[1]	762	4,084

(1) $1.9 billion of the total net unfunded projected benefit obligation is due to Eletropaulo in Brazil.

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, 2012 and 2011:

	December 31,			
	2012		2011	
	U.S.	Foreign	U.S.	Foreign
Benefit Obligation:				
Discount rates	3.86%	8.25%[2]	4.67%	9.52%[2]
Rates of compensation increase	3.94%[1]	6.45%	3.94%[1]	5.98%
Periodic Benefit Cost:				
Discount rate	4.67%	9.52%	5.38%	9.82%
Expected long-term rate of return on plan assets	7.28%	10.81%	7.49%	11.08%
Rate of compensation increase	3.94%[1]	5.98%	3.94%[1]	5.98%

(1) A U.S. subsidiary of the Company has a defined benefit obligation of $764 million and $679 million as of December 31, 2012 and 2011, 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 2012. They also may not be additive, so the impact of changing multiple factors simultaneously cannot be calculated by combining the individual sensitivities shown. The funded status as of December 31, 2012 is affected by the assumptions as of that date. Pension expense for 2012 is affected by the December 31, 2011 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	$(48)
Decrease of 1% in the discount rate	38
Increase of 1% in the long-term rate of return on plan assets	(47)
Decrease of 1% in the long-term rate of return on plan assets	47

The following table summarizes the components of the net periodic benefit cost, both domestic and foreign, for the years ended December 31, 2012 through 2010:

	December 31,					
	2012		2011		2010	
Components of Net Periodic Benefit Cost:	U.S.	Foreign	U.S.	Foreign	U.S.	Foreign
	(in millions)					
Service cost	$ 14	$ 19	$ 8	$ 19	$ 7	$ 16
Interest cost	48	481	33	564	32	510
Expected return on plan assets	(55)	(418)	(33)	(508)	(30)	(427)
Amortization of initial net asset	—	—	—	—	—	(1)
Amortization of prior service cost	4	—	4	—	3	—
Amortization of net loss	19	37	13	23	12	38
Loss on curtailment	—	—	—	5	—	—
Settlement gain recognized	—	1	—	—	—	1
Total pension cost	$ 30	$ 120	$ 25	$ 103	$ 24	$ 137

The following table summarizes the amounts reflected in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheet as of December 31, 2012, that have not yet been recognized as components of net periodic benefit cost and amounts expected to be reclassified to earnings in the next fiscal year:

	December 31, 2012			
	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	—	(1,873)	—	(83)
Total	$—	$(1,875)	$—	$ (83)

The following table summarizes the Company's target allocation for 2012 and pension plan asset allocation, both domestic and foreign, as of December 31, 2012 and 2011:

	Target Allocations		Percentage of Plan Assets as of December 31,			
			2012		2011	
Asset Category	U.S.	Foreign	U.S.	Foreign	U.S.	Foreign
Equity securities	41%	15% - 30%	32.28%	19.76%	34.12%	23.48%
Debt securities	49%	59% - 85%	46.66%	76.21%	38.58%	72.55%
Real estate	2%	0% - 4%	0.00%	2.57%	0.00%	2.34%
Other	8%	0% - 6%	21.06%	1.46%	27.30%	1.63%
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, 2012 and 2011:

	December 31, 2012				December 31, 2011			
U.S. Plans	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
				(in millions)				
Equity securities:								
Common stock	$134	$—	$—	$134	$120	$—	$—	$120
Mutual funds	151	—	—	151	140	—	—	140
Debt securities:								
Government debt securities	32	—	—	32	31	—	—	31
Corporate debt securities	4	149	—	153	—	78	—	78
Mutual funds[1]	227	—	—	227	135	—	—	135
Other debt securities	—	—	—	—	—	50	—	50
Other:								
Cash and cash equivalents	43	—	—	43	43	—	—	43
Other investments	38	105	—	143	72	93	—	165
Total plan assets	$629	$254	$—	$883	$541	$221	$—	$762

(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, 2012 and 2011:

Foreign Plans	December 31, 2012 Level 1	Level 2	Level 3	Total	December 31, 2011 Level 1	Level 2	Level 3	Total
				(in millions)				
Equity securities:								
Common stock	$ 28	$ —	$—	$ 28	$ 26	$ —	$—	$ 26
Mutual funds	457	—	—	457	427	—	—	427
Private equity(1)	—	—	446	446	—	—	580	580
Debt securities:								
Certificates of deposit	—	3	—	3	—	5	—	5
Unsecured debentures	—	16	—	16	—	20	—	20
Government debt securities	9	206	—	215	6	221	—	227
Mutual funds(2)	139	3,208	—	3,347	125	2,805	—	2,930
Other debt securities	—	10	—	10	—	10	—	10
Real estate:								
Real estate(1)	—	—	121	121	—	—	103	103
Other:								
Cash and cash equivalents	1	—	—	1	—	—	—	—
Participant loans(3)	—	—	68	68	—	—	72	72
Total plan assets	$634	$3,443	$635	$4,712	$584	$3,061	$755	$4,400

(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, 2012 and 2011:

	Year Ended December 31, 2012	2011
	(in millions)	
Balance at January 1	$755	$703
Actual return on plan assets:		
Returns relating to assets still held at reporting date	(60)	167
Returns relating to assets sold during the period	—	28
Purchases, sales and settlements, net	3	(48)
Change due to exchange rate changes	(63)	(95)
Balance at December 31	$635	$755

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 2013	$ 53	$ 165
Expected benefit payments for fiscal year ending:		
2013	58	425
2014	60	439
2015	62	457
2016	64	474
2017	66	492
2018 - 2022	354	2,739

16. EQUITY

Accumulated Other Comprehensive Loss

The components of accumulated other comprehensive loss, net of tax, as of December 31, 2012 and 2011 were as follows:

	December 31,	
	2012	2011
	(in millions)	
Foreign currency translation adjustment, net	$2,057	$1,967
Unrealized derivative losses, net	481	534
Unfunded pension obligations, net	382	257
Total	$2,920	$2,758

Dividend

The Company paid a dividend of $0.04 per outstanding share to its common stockholders in November 2012.

On December 7, 2012, the Board of Directors of the Company declared a quarterly common stock dividend of $0.04 per share payable on February 15, 2013 to shareholders of record at the close of business on February 1, 2013.

Stock Repurchase Program

The Company's Board of Directors recently increased the share buyback authorization by $300 million, all of which is available. Under the program, the Company may 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 it can be modified or terminated by the Company's Board at any time.

During the year ended December 31, 2012, shares of common stock repurchased under this plan totaled 24,790,384 at a total cost of $301 million plus a nominal amount of commissions (average of $12.16 per share including commissions), bringing the cumulative total purchases under the program to 58,715,189 shares at a total cost of $680 million, which includes a nominal amount of commissions (average of $11.58 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 66,415,984 and 42,386,961 shares were held in treasury stock at December 31, 2012 and 2011, respectively. The Company has not retired any shares held in treasury during the years ended December 31, 2012, 2011 or 2010.

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 1,240 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 (loss) attributable to The AES Corporation and transfers (to) from noncontrolling interests for the years ended December 31, 2012 and 2011:

	December 31,	
	2012	2011
	(in millions)	
Net income (loss) attributable to The AES Corporation	$(912)	$ 58
Transfers (to) from the noncontrolling interests:		
Net increase in The AES Corporation's paid-in capital for sale of subsidiary shares	7	19
Increase in The AES Corporation's paid-in capital for purchase of subsidiary shares	4	—
Net transfers (to) from noncontrolling interest	11	19
Change from net income attributable to The AES Corporation and transfers (to) from noncontrolling interests	$(901)	$ 77

17. SEGMENT AND GEOGRAPHIC INFORMATION

During the fourth quarter of 2012, the Company completed the restructuring of its operational management and reporting process. The segment reporting structure uses the Company's management reporting structure as its foundation to reflect how the Company manages the business internally with further aggregation by geographic regions to provide better socio-political-economic understanding of our business. The management reporting structure is organized along six strategic business units ("SBUs") – led by our Chief Operating Officer ("COO"), who in turn reports to our Chief Executive Officer ("CEO"). Upon the application of the accounting guidance for segment reporting, the Company has identified eight reportable segments based on the six strategic business units. All prior period results have been retrospectively revised to reflect the new segment reporting structure which includes:

- US—Generation;

- US—Utilities;
- Andes—Generation;
- Brazil—Generation;
- Brazil—Utilities;
- MCAC—Generation;
- EMEA—Generation;
- Asia—Generation

Corporate and Other—The Company's EMEA and MCAC Utilities operating segments are reported within "Corporate and Other" because they do not meet the criteria to allow for aggregation with another operating segment or the quantitative thresholds that would require separate disclosure under the 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 adjusted PTC. "Corporate and Other" also includes corporate overhead costs which are not directly associated with the operations of our eight reportable segments and other intercompany charges such as self-insurance premiums which are fully eliminated in consolidation.

During the fourth quarter 2012, the Company changed its primary segment performance measure from adjusted gross margin to adjusted pre-tax contribution ("Adjusted PTC"). Adjusted PTC, a non-GAAP measure, is defined by the Company as pre-tax income from continuing operations attributable to AES excluding unrealized gains or losses related to derivative transactions, unrealized foreign currency gains or losses, significant gains or losses due to dispositions and acquisitions of business interests, significant losses due to impairments and costs due to the early retirement of debt. The Company has concluded that Adjusted PTC best reflects the underlying business performance of the Company and is the most relevant measure considered in the Company's internal evaluation of the financial performance of its segments. Additionally, given its large number of businesses and complexity, the Company has also concluded that Adjusted PTC is a more transparent measure that better assists the investor in determining which businesses have the greatest impact on the overall Company results.

Total revenue includes inter-segment revenue related to the transfer of electricity from generation plants to utilities within Brazil. No material inter-segment revenue relationships exist between other segments. Corporate allocations include certain self-insurance activities which are reflected within segment adjusted PTC. All intra-segment activity has been eliminated with respect to revenue and adjusted PTC within the segment. Inter-segment activity has been eliminated within the total consolidated results. Asset information for businesses that were discontinued or classified as held for sale as of December 31, 2012 is segregated and is shown in the line "Discontinued Businesses" in the accompanying segment tables.

The tables below present the breakdown of reportable segment balance sheet and income statement data as of and for the years ended December 31, 2012 through 2010:

	Total Revenue			Intersegment			External Revenue		
	2012	2011	2010	2012	2011	2010	2012	2011	2010
					(in millions)				
Revenue									
US—Generation	$ 861	$ 784	$ 806	$ —	$ (2)	$ —	$ 861	$ 782	$ 806
US—Utilities	2,898	1,326	1,145	—	—	—	2,898	1,326	1,145
Andes—Generation	3,020	2,989	2,519	(33)	(36)	—	2,987	2,953	2,519
Brazil—Generation	1,087	1,128	1,031	(1,019)	(1,109)	(1,015)	68	19	16
Brazil—Utilities	5,720	6,621	6,340	—	—	—	5,720	6,621	6,340
MCAC—Generation	1,723	1,575	1,400	(2)	(5)	(3)	1,721	1,570	1,397
EMEA—Generation	1,376	1,501	1,208	(33)	(34)	(31)	1,343	1,467	1,177
Asia—Generation	738	626	618	—	—	—	738	626	618
Corporate and Other	1,809	1,565	1,435	(4)	(6)	(10)	1,805	1,559	1,425
Total Revenue	$19,232	$18,115	$16,502	$(1,091)	$(1,192)	$(1,059)	$18,141	$16,923	$15,443

	Total Adjusted Pre-Tax Contribution			Intersegment			External Adjusted Pre-Tax Contribution		
	2012	2011	2010	2012	2011	2010	2012	2011	2010
					(in millions)				
Adjusted Pre-Tax Contribution[1]									
US—Generation	$ 171	$ 101	$ 75	$ 38	$ 51	$ 6	$ 209	$ 152	$ 81
US—Utilities	239	80	130	2	1	2	241	81	132
Andes—Generation	369	508	322	(16)	(32)	6	353	476	328
Brazil—Generation	169	189	177	(244)	(267)	(251)	(75)	(78)	(74)
Brazil—Utilities	152	226	214	165	179	192	317	405	406
MCAC—Generation	363	290	238	8	1	(23)	371	291	215
EMEA—Generation	381	273	201	(18)	(4)	4	363	269	205
Asia—Generation	201	99	145	2	2	2	203	101	147
Corporate and Other	(668)	(688)	(547)	63	69	62	(605)	(619)	(485)
Total Adjusted Pre-Tax Contribution	1,377	1,078	955	—	—	—	1,377	1,078	955
Reconciliation to Income from Continuing Operations before Taxes and Equity Earnings of Affiliates:									
Non-GAAP Adjustments:									
Unrealized derivatives gains (losses)							(118)	(11)	2
Unrealized foreign currency gains (losses)							18	(38)	38
Disposition/acquisition gains							206	—	—
Impairment losses							(1,936)	(271)	(322)
Debt retirement losses							(16)	(46)	(29)
Pre-tax contribution							(469)	712	644
Add: Income from continuing operations before taxes, attributable to noncontrolling interests							817	1,497	1,430
Less: Net equity in earnings of affiliates							34	(2)	184
Income from continuing operations before taxes and equity earnings of affiliates							$ 314	$2,211	$1,890

(1) Adjusted pre-tax contribution in each segment before intersegment eliminations includes the effect of intercompany transactions with other segments except for interest and charges for certain management fees.

	Total Assets			Depreciation and Amortization			Capital Expenditures		
	2012	2011	2010	2012	2011	2010	2012	2011	2010
	(in millions)								
US—Generation	$ 3,259	$ 3,461	$ 3,550	$ 129	$ 131	$ 148	$ 75	$ 174	$ 290
US—Utilities	7,534	9,397	3,138	396	178	161	324	232	177
Andes—Generation	6,619	6,482	6,164	174	151	123	389	385	463
Brazil—Generation	1,590	1,777	2,035	53	59	40	65	105	58
Brazil—Utilities	8,120	8,825	8,967	228	273	211	652	633	559
MCAC—Generation	4,293	4,246	4,009	112	94	94	160	183	136
EMEA—Generation	4,578	4,491	4,302	150	165	136	229	329	343
Asia—Generation	2,625	1,830	1,861	32	33	33	229	177	24
Discontinued businesses	25	1,625	2,791	3	68	122	9	92	107
Corp and Other & eliminations	3,187	3,212	3,694	117	110	110	138	151	176
Total	$41,830	$45,346	$40,511	$1,394	$1,262	$1,178	$2,270	$2,461	$2,333

	Interest Income			Interest Expense		
	2012	2011	2010	2012	2011	2010
	(in millions)					
US—Generation	$ 1	$ 1	$ 9	$ 62	$ 72	$ 74
US—Utilities	2	—	1	231	124	119
Andes—Generation	20	20	13	128	126	98
Brazil—Generation	26	47	73	39	62	85
Brazil—Utilities	252	298	273	266	390	341
MCAC—Generation	31	20	26	167	141	157
EMEA—Generation	8	5	4	97	109	75
Asia—Generation	6	2	3	46	47	52
Corp and Other & eliminations	3	6	5	536	482	448
Total	$349	$399	$407	$1,572	$1,553	$1,449

	Investments in and Advances to Affiliates			Equity in Earnings (Loss)		
	2012	2011	2010	2012	2011	2010
	(in millions)					
US—Generation	$ (1)	$ (1)	$ —	$—	$—	$ (2)
US—Utilities	1	—	—	—	—	—
Andes—Generation	198	188	150	18	35	48
Brazil—Generation	—	—	—	—	—	—
Brazil—Utilities	—	—	—	—	—	—
MCAC—Generation	24	19	20	5	(2)	—
EMEA—Generation	454	512	385	8	10	20
Asia—Generation	202	366	478	32	5	6
Discontinued businesses	—	—	—	—	—	—
Corp and Other & eliminations	318	338	287	(29)	(50)	112
Total	$1,196	$1,422	$1,320	$ 34	$ (2)	$184

The table below presents information, by country, about the Company's consolidated operations for each of the years ended December 31, 2012 through 2010 and as of December 31, 2012 and 2011, 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	
	2012	2011	2010	2012	2011
			(in millions)		
United States[1]	$ 3,764	$ 2,113	$ 1,952	$ 7,663	$ 7,730
Non-U.S.:					
Brazil[2]	5,788	6,640	6,355	5,756	5,896
Chile	1,679	1,608	1,355	2,993	2,781
Argentina[3]	857	979	771	278	293
El Salvador	850	752	648	267	268
Dominican Republic	761	674	535	670	662
Philippines	559	480	501	800	766
United Kingdom[4]	505	587	364	579	523
Ukraine	491	418	356	112	94
Cameroon	457	386	422	989	901
Colombia	453	365	393	383	384
Mexico	397	404	409	759	779
Bulgaria[5]	369	251	44	1,611	1,624
Puerto Rico	293	298	253	570	581
Panama	266	189	194	1,069	1,040
Sri Lanka	169	140	100	8	22
Kazakhstan	151	145	138	141	86
Jordan	121	124	120	222	216
Spain[6]	119	258	411	—	—
Hungary[7]	—	—	10	—	—
Qatar[8]	—	—	—	—	—
Pakistan[9]	—	—	—	—	—
Oman[10]	—	—	—	—	—
Vietnam	—	—	—	887	138
Other Non-U.S. [11]	92	112	112	156	217
Total Non-U.S.	14,377	14,810	13,491	18,250	17,271
Total	$18,141	$16,923	$15,443	$25,913	$25,001

(1) Excludes revenue of $39 million, $374 million and $662 million for the years ended December 31, 2012, 2011 and 2010, respectively, and property, plant and equipment of $619 million as of December 31, 2011, related to Eastern Energy, Thames, Ironwood, and Red Oak which were reflected as discontinued operations and assets held for sale in the accompanying Consolidated Statements of Operations and Consolidated Balance Sheets. Additionally property, plant and equipment excludes $25 million and $45 million as of December 31, 2012 and 2011, respectively, related to wind turbines which were reflected as assets held for sale in the accompanying Consolidated Balance Sheets.

(2) Excludes revenue of $124 million and $118 million for the years ended December 31, 2011 and 2010, respectively, related to Brazil Telecom, which was reflected as discontinued operations in the accompanying Consolidated Statements of Operations.

(3) Excludes revenue of $102 million and $116 million for the years ended December 31, 2011 and 2010, respectively, related to our Argentina distribution businesses, which were reflected as discontinued operations in the accompanying Consolidated Statements of Operations.

(4) Excludes revenue of $5 million, $17 million and $21 million for the years ended December 31, 2012, 2011 and 2010, respectively, related to carbon reduction projects, which were reflected as discontinued operations in the accompanying Consolidated Statements of Operations.

(5) Our wind project in Bulgaria started operations in 2010 and Maritza started operations in June 2011.

(6) Excludes property, plant and equipment of $620 million as of December 31, 2011, related to Cartagena, which was reflected as assets held for sale in the accompanying Consolidated Balance Sheet.

(7) Excludes revenue of $18 million, $219 million and $287 million for the years ended December 31, 2012, 2011 and 2010, respectively, and property, plant and equipment of $5 million as of December 31, 2011, related to Borsod, Tiszapalkonya and Tisza II, which were reflected as discontinued operations and assets held for sale in the accompanying Consolidated Statements of Operations and Consolidated Balance Sheets.

(8) Excludes revenue of $129 million for the year ended December 31, 2010, related to Ras Laffan, which was reflected as discontinued operations in the accompanying Consolidated Statements of Operations.

(9) Excludes revenue of $299 million for the year ended December 31, 2010, related to Lal Pir and Pak Gen, which were reflected as discontinued operations in the accompanying Consolidated Statements of Operations.

(10) Excludes revenue of $62 million for the year ended December 31, 2010, related to Barka, which was reflected as discontinued operations in the accompanying Consolidated Statements of Operations.

(11) Excludes revenue of $1 million for each of the years ended December 31, 2012 and 2011, related to alternative energy and carbon reduction projects, which were reflected as discontinued operations in the accompanying Consolidated Statements of Operations.

18. SHARE-BASED COMPENSATION

STOCK OPTIONS—AES grants options to purchase shares of common stock under stock option plans to employees and non-employee directors. 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 2012, 2011 and 2010 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, 2012, approximately 16 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 following table presents the weighted average fair value of each option grant and the underlying weighted average assumptions, as of the grant date, using the Black-Scholes option-pricing model:

	December 31,		
	2012	2011	2010
Expected volatility	26%	31%	38%
Expected annual dividend yield	1%	0%	0%
Expected option term (years)	6	6	6
Risk-free interest rate	1.08%	2.65%	2.86%
Fair value at grant date	$3.04	$4.54	$5.08

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.

The Company uses 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 is used for stock options granted during 2012, 2011 and 2010. 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.

The following table summarizes the components of stock-based compensation related to employee stock options recognized in the Company's financial statements:

	December 31,		
	2012	2011	2010
		(in millions)	
Pre-tax compensation expense	$ 2	$ 7	$ 9
Tax benefit	(1)	(2)	(2)
Stock options expense, net of tax	$ 1	$ 5	$ 7
Total intrinsic value of options exercised	$10	$ 8	$ 2
Total fair value of options vested	5	7	11
Cash received from the exercise of stock options	9	4	2

No cash was used to settle stock options or compensation cost capitalized as part of the cost of an asset for the years ended December 31, 2012, 2011 and 2010. As of December 31, 2012, $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.

A summary of the option activity for the year ended December 31, 2012 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, 2011	9,458	$13.82		
Exercised	(1,596)	5.92		
Forfeited and expired	(1,123)	16.65		
Granted	1,144	13.03		
Outstanding at December 31, 2012	7,883	$14.91	4.5	$5
Vested and expected to vest at December 31, 2012	7,775	$14.94	4.4	$5
Eligible for exercise at December 31, 2012	6,100	$15.55	3.6	$5

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 2012 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, 2012. 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 2012, AES has estimated a weighted average forfeiture rate of 13.66% for stock options granted in 2012. 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 $3 million on a straight-line basis over a three year period (approximately $1 million per year) related to stock options granted during the year ended December 31, 2012.

RESTRICTED STOCK

Restricted Stock Units—The Company issues restricted stock units ("RSUs") 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 and afterwards. 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, 2012, 2011, and 2010, RSUs issued 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 granted to employees during the years ended December 31, 2012, 2011, and 2010 had grant date fair values per RSU of $13.54, $12.65 and $12.18, respectively.

The following table summarizes the components of the Company's stock-based compensation related to its employee RSUs recognized in the Company's consolidated financial statements:

	December 31,		
	2012	2011	2010
	(in millions)		
RSU expense before income tax	$11	$11	$11
Tax benefit	(3)	(3)	(2)
RSU expense, net of tax	$ 8	$ 8	$ 9
Total value of RSUs converted[1]	$ 9	$ 5	$ 5
Total fair value of RSUs vested	$12	$10	$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, 2012, 2011 and 2010. As of December 31, 2012, $14 million of total unrecognized compensation cost related to RSUs is expected to be recognized over a weighted average period of approximately 1.8 years. There were no modifications to RSU awards during the year ended December 31, 2012.

A summary of the activity of RSUs for the year ended December 31, 2012 follows (number of RSUs in thousands):

	RSUs	Weighted Average Grant Date Fair Values	Weighted Average Remaining Vesting Term
Nonvested at December 31, 2011	2,355	$11.40	
Vested	(1,138)	10.31	
Forfeited and expired	(407)	12.88	
Granted	1,282	13.54	
Nonvested at December 31, 2012	2,092	$13.02	1.6
Vested at December 31, 2012	2,685	$10.66	
Vested and expected to vest at December 31, 2012	4,602	$11.64	

The Company initially recognizes compensation cost on the estimated number of instruments for which the requisite service is expected to be rendered. In 2012, AES has estimated a weighted average forfeiture rate of 18.82% for RSUs granted in 2012. 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 $14 million on a straight-line basis over a three year period related to RSUs granted during the year ended December 31, 2012.

The table below summarizes the RSUs that vested and were converted during the years ended December 31, 2012, 2011 and 2010 (number of RSUs in thousands):

	December 31,		
	2012	2011	2010
RSUs vested during the year	1,138	982	929
RSUs converted during the year, net of shares withheld for taxes	761	442	386
Shares withheld for taxes	312	150	127

Performance Stock Units—The Company issues performance stock units ("PSUs") to officers under its long-term compensation plan. PSUs are restricted stock units of which 50% of the units awarded 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 Utilities Sector Index over the three-year measurement period beginning on January 1st of the grant year and ending on December 31st of the third year and (b) for the units subject to the performance condition if the Company's actual Adjusted EBITDA meets the performance target over the three-year measurement period beginning on January 1, 2012 and ending on December 31, 2014. The market and performance condition determines the vesting and final share equivalent per PSU and can result in earning an award payout range of 0% to 200%, depending on the achievement. In all circumstances, PSUs 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.

The effect of the market condition on PSUs issued to officers of the Company during 2012 is reflected in the award's fair value on the grant date. The results of the valuation estimated the fair value at $19.75 per share, equating to 144% of the Company's closing stock price on the date of grant. PSUs that included a market condition granted during the year ended December 31, 2012, 2011 and 2010 had a grant date fair value per RSU of $19.75, $17.68 and $11.57, respectively. The fair value of the PSUs with a performance condition had a grant date fair value of $13.70 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. If the fair value of the market condition was not applied to PSUs issued to officers, the total grant date fair value of PSUs granted during the year ended December 31, 2012 would have decreased by $2 million.

Restricted stock units with a market condition were awarded to officers of the Company prior to 2011 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 and afterwards.

The following table summarizes the components of the Company's stock-based compensation related to its PSUs recognized in the Company's consolidated financial statements:

	December 31,		
	2012	2011	2010
		(in millions)	
PSU expense before income tax	$ 5	$ 5	$ 4
Tax benefit	(1)	(1)	(1)
PSU expense, net of tax	$ 4	$ 4	$ 3
Total value of PSUs converted[1]	$—	$—	$ 3
Total fair value of PSUs vested	2	—	—

(1) Amount represents fair market value on the date of conversion.

There was no cash used to settle PSUs or compensation cost capitalized as part of the cost of an asset for the years ended December 31, 2012, 2011 and 2010. As of December 31, 2012, $6 million of total unrecognized compensation cost related to PSUs is expected to be recognized over a weighted average period of approximately 1.9 years. There were no modifications to PSU awards during the year ended December 31, 2012.

A summary of the activity of PSUs for the year ended December 31, 2012 follows (number of PSUs in thousands):

	PSUs	Weighted Average Grant Date Fair Values	Weighted Average Remaining Vesting Term
Nonvested at December 31, 2011	1,357	$10.78	
Vested	(343)	6.68	
Forfeited and expired	(464)	10.90	
Granted	532	16.73	
Nonvested at December 31, 2012	1,082	$14.96	1.3
Vested at December 31, 2012	343	$ 6.68	
Vested and expected to vest at December 31, 2012	1,335	12.75	

The Company initially recognizes compensation cost on the estimated number of instruments for which the requisite service is expected to be rendered. In 2012, AES has estimated a forfeiture rate of 13.81% for PSUs granted in 2012. 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 $8 million on a straight-line basis over a three year period (approximately $2.7 million per year) related to PSUs granted during the year ended December 31, 2012.

The table below summarizes the PSUs that vested and were converted during the years ended 2012, 2011 and 2010 (number of PSUs in thousands):

	December 31,		
	2012	2011	2010
PSUs vested during the year	343	—	—
PSUs converted during the year, net of shares withheld for taxes	—	—	245
Shares withheld for taxes	—	—	102

19. CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES

Our subsidiaries IPL and DPL had outstanding shares of cumulative preferred stock of $78 million at December 31, 2012 and 2011.

IPL had $60 million of cumulative preferred stock outstanding at December 31, 2012 and 2011, which represented five series of preferred stock. The total annual dividend requirements were approximately $3 million at December 31, 2012 and 2011. 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 had $18 million of cumulative preferred stock outstanding at December 31, 2012, 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, 2012. 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.

20. OTHER INCOME AND EXPENSE

Other Income

Other income generally includes gains on asset sales and extinguishments of liabilities, favorable judgments on contingencies, and other income from miscellaneous transactions. The components of other income are summarized as follows:

	Years Ended December 31,		
	2012	2011	2010
		(in millions)	
Insurance proceeds	$ 40	$ 11	$ 1
Gain on sale of assets	21	47	12
Tax credit settlement	—	31	—
Gain on extinguishment of tax and other liabilities	—	14	62
Other	44	46	25
Total other income	$105	$149	$100

Other income of $105 million for the year ended December 31, 2012 included the receipt of insurance proceeds related to a claim in Panama for damage associated with the Esti tunnel, the release of a reserve recorded against inventory at Ballylumford and the receipt of dividends from a cost method investment at Gener. Other income also includes the sale of land adjacent to Deepwater and the associated water permits, water right sales at Gener and the gain on sale of assets at Eletropaulo.

Other income of $149 million for the year ended December 31, 2011 included a 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, the sale of Huntington Beach units 3 & 4 at Southland, the sale of land and minerals rights at IPL and insurance proceeds related to the claim in Panama that is described above.

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 non-controlling interest was $9 million. Other income also included a gain on sale of assets at Eletropaulo.

Other Expense

Other expense generally includes losses on asset sales, losses on extinguishment of debt, legal contingencies and losses from other miscellaneous transactions. The components of other expense are summarized as follows:

	Years Ended December 31,		
	2012	2011	2010
		(in millions)	
Loss on sale and disposal of assets	$ 64	$ 68	$ 84
Loss on extinguishment of debt	8	62	37
Gener gas settlement	—	—	72
Wind Generation transaction costs	—	—	22
Other	21	23	17
Total other expense	$ 93	$153	$232

Other expense of $93 million for the year ended December 31, 2012 was primarily due to losses on the disposal of assets mainly at Eletropaulo and losses related to the early retirement of debt at the Parent Company and at Eletropaulo. Additionally, other expense included a tax penalty at Chivor and a reduction in the 2011 receivable expected from the indemnity agreement described above in other income at Los Mina.

Other expense of $153 million for the year ended December 31, 2011 included $68 million related to the loss on disposal of assets mainly at Eletropaulo and TermoAndes, $36 million related to the premium paid on early retirement of debt at Gener and $15 million related to the early retirement of senior notes due in 2011 at IPL.

Other expense of $232 million for the year ended December 31, 2010 included losses on disposal of assets totaling $84 million, mainly 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. Additionally, other expense included $72 million for a settlement agreement of gas transportation contracts at Gener as well as previously capitalized transaction costs of $22 million that were incurred in connection with the preparation for the sale of a non-controlling interest in our Wind generation business, which were written off upon the expiration of the letter of intent on June 30, 2010.

21. ASSET IMPAIRMENT EXPENSE

Asset impairment expense for the years ended December 31, 2012, 2011, and 2010 consisted of:

	2012	2011	2010
		(in millions)	
Wind turbines and projects	$ 41	$116	$—
Kelanitissa	19	42	—
St. Patrick	11	—	—
Southland (Huntington Beach)	—	—	200
Deepwater	—	—	79
Other	2	15	25
Total	$ 73	$173	$304

Wind Turbines and Projects— During the third quarter of 2012, the Company determined that all wind turbines held in storage met the held-for-sale criteria due to the ongoing receipt of offers from potential buyers and less viable internal deployment scenarios. Accordingly, the Company measured the turbines at fair value less cost to sell under the market approach. The turbines with a carrying amount of $45 million were written down to their fair value less cost to sell of $25 million, which resulted in an impairment expense of $20 million. These turbines continue to meet the held-for-sale criteria as of December 31, 2012. The turbines were previously evaluated for impairment in the third quarter of 2011 due to a reduction in wind turbine market pricing and advances in turbine technology. At that time, the Company had also concluded that it was more likely than not that certain non-refundable deposits it had made in prior years to a turbine manufacturer for the purchase of wind turbines were not recoverable due to the availability of more advanced and lower cost turbines in the market. As a result, the Company had recognized asset impairment expense of $116 million related to these turbines and deposits in the third quarter of 2011.

During 2012, the Company also determined that two early-stage wind development projects that were capitalizing certain project costs were no longer probable because of the Company's shift in capital allocation for developing these projects. The Company assessed the value of the projects using the market approach and, after consultation with third party valuation firms and internal development staff, the fair value was determined to be zero. Asset impairment expense of $21 million was recognized during 2012 for these wind development projects. These wind turbines and projects are reported in the US Generation segment.

Kelanitissa—We continue 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 requirement to transfer the plant to the government at the end of our PPA and the expectation of lower future operating cash flows. During 2012, the Company recognized asset impairment expense of $19 million for the long-lived assets of Kelanitissa. Our evaluations during this period indicated that the long-lived assets were no longer recoverable and, accordingly, were written down to their estimated fair value of $10 million based on a discounted cash flow analysis. The long-lived assets had a carrying amount of $29 million prior to the recognition of asset impairment expense. Kelanitissa was previously evaluated for impairment in 2011 due to the reasons described above. These evaluations resulted in asset impairment expense of $42 million during the year ended December 31, 2011. Kelanitissa is reported in the Asia Generation segment.

St. Patrick—During the second quarter of 2012, the Company received approval from its Board of Directors for the sale of its wholly-owned subsidiary Ferme Eolienne Saint Patrick SAS ("St. Patrick"). Upon meeting the held for sale criteria long-lived assets with a carrying amount of $33 million were written down to their fair value of $22 million and an impairment expense of $11 million was recorded. The sale transaction subsequently closed on June 28, 2012. St. Patrick is reported in the EMEA generation segment.

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 US Generation segment.

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 US Generation segment.

22. INCOME TAXES

Income Tax Provision

The following table summarizes the expense for income taxes on continuing operations, for the years ended December 31, 2012, 2011 and 2010:

	December 31,		
	2012	2011	2010
		(in millions)	
Federal:			
Current	$—	$ —	$ (8)
Deferred	24	(150)	(125)
State:			
Current	(2)	1	1
Deferred	(11)	1	(19)
Foreign:			
Current	562	852	678
Deferred	135	(70)	66
Total	$708	$ 634	$ 593

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, 2012, 2011 and 2010:

	December 31,		
	2012	2011	2010
Statutory Federal tax rate	35%	35%	35%
State taxes, net of Federal tax benefit	-15%	0%	-3%
Taxes on foreign earnings	-21%	-3%	-2%
Valuation allowance	13%	-3%	0%
Gain (loss) on sale of businesses	0%	0%	4%
Chilean withholding tax reversals	0%	0%	-3%
Change in tax law	13%	0%	0%
DPL goodwill impairment	203%	0%	0%
Other—net	-3%	0%	0%
Effective tax rate	225%	29%	31%

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 Noncurrent Assets and Other Noncurrent Liabilities, respectively, on the accompanying Consolidated Balance Sheets. The following table summarizes the income taxes receivable and payable as of December 31, 2012 and 2011:

	December 31,	
	2012	2011
	(in millions)	
Income taxes receivable—current	$296	$563
Income taxes receivable—noncurrent	15	21
Total income taxes receivable	$311	$584
Income taxes payable—current	$405	$759
Income taxes payable—noncurrent	2	3
Total income taxes payable	$407	$762

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, 2012, the Company had federal net operating loss carryforwards for tax purposes of approximately $2.2 billion expiring in years 2023 to 2032. Approximately $76 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 2032, and federal alternative minimum tax credits of approximately $5 million that carry forward without expiration. The Company had state net operating loss carryforwards as of December 31, 2012 of approximately $5.8 billion expiring in years 2016 to 2032. As of December 31, 2012, the Company had foreign net operating loss carryforwards of approximately $3.3 billion that expire at various times beginning in 2013 and some of which carry forward without expiration, and tax credits available in foreign jurisdictions of approximately $23 million, $1 million of which expire in 2013 to 2015, $3 million of which expire in 2016 to 2023 and $19 million of which carryforward without expiration.

Valuation allowances increased $5 million during 2012 to $0.9 billion at December 31, 2012. This net increase was primarily the result of valuation allowance activity at certain U.S. state jurisdictions.

Valuation allowances decreased $376 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 Brazilian 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, 2012 and 2011:

	December 31, 2012	December 31, 2011
	(in millions)	
Differences between book and tax basis of property	$(2,067)	$(1,909)
Cumulative translation adjustment	(43)	(39)
Other taxable temporary differences	(419)	(321)
Total deferred tax liability	(2,529)	(2,269)
Operating loss carryforwards	1,604	1,481
Capital loss carryforwards	108	112
Bad debt and other book provisions	358	463
Retirement costs	619	360
Tax credit carryforwards	46	46
Other deductible temporary differences	555	516
Total gross deferred tax asset	3,290	2,978
Less: valuation allowance	(906)	(901)
Total net deferred tax asset	2,384	2,077
Net deferred tax asset/(liability)	$ (145)	$ (192)

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 $81 million, $60 million and $60 million for the years ended December 31, 2012, 2011 and 2010, respectively. The per share effect of these benefits after noncontrolling interests was $0.10, $0.07 and $0.07 for the year ended December 31, 2012, 2011 and 2010, 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, 2012, 2011 and 2010:

	December 31, 2012	December 31, 2011	December 31, 2010
		(in millions)	
U.S.	$(1,915)	$ (526)	$ (539)
Non-U.S.	2,229	2,737	2,429
Total	$ 314	$2,211	$1,890

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, 2012 and 2011, the total amount of gross accrued income tax related interest included in the Consolidated Balance Sheets was $18 million and $15 million, respectively. The total amount of gross accrued income tax related penalties included in the Consolidated Balance Sheets as of December 31, 2012 and 2011 was $4 million and $4 million, respectively.

The total expense (benefit) for interest related to unrecognized tax benefits for the years ended December 31, 2012, 2011 and 2010 amounted to $3 million, $3 million and $(10) million, respectively. For the years ended December 31, 2012, 2011 and 2010, the total expense (benefit) for penalties related to unrecognized tax benefits amounted to $1 million, $0 million and $(1) 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	2006-2012
Brazil	2007-2012
Cameroon	2008-2012
Chile	2009-2012
Colombia	2010-2012
El Salvador	2009-2012
United Kingdom	2009-2012
United States (Federal)	1994-2012

As of December 31, 2012, 2011 and 2010, the total amount of unrecognized tax benefits was $481 million, $471 million and $437 million, respectively. The total amount of unrecognized tax benefits that would benefit the effective tax rate as of December 31, 2012, 2011 and 2010 is $450 million, $424 million and $412 million, respectively, of which $45 million, $47 million and $51 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, 2012 is estimated to be between $90 million and $110 million.

The following is a reconciliation of the beginning and ending amounts of unrecognized tax benefits for the years ended December 31, 2012, 2011 and 2010:

	2012	2011	2010
		(in millions)	
Balance at January 1	$471	$437	$510
Additions for current year tax positions	12	7	14
Additions for tax positions of prior years	34	49	51
Reductions for tax positions of prior years	(29)	(18)	(46)
Effects of foreign currency translation	—	(1)	(2)
Settlements	(6)	—	(67)
Lapse of statute of limitations	(1)	(3)	(23)
Balance at December 31	$481	$471	$437

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, 2012. Our effective tax rate and net income in any given future period could therefore be materially impacted.

23. DISCONTINUED OPERATIONS AND HELD FOR SALE BUSINESSES

Discontinued operations include the results of the following businesses:

- Tisza II (sold in December 2012);
- Red Oak and Ironwood (sold in April 2012);
- 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 of discontinued operations for the years ended December 31, 2012, 2011 and 2010 is provided in the tables below:

	Year ended December 31,		
	2012	2011	2010
		(in millions)	
Revenue	$ 66	$ 836	$1,695
Loss from operations of discontinued businesses, before income tax	$(10)	$(157)	$ (770)
Income tax (expense) benefit	(3)	26	284
Loss from operations of discontinued businesses, after income tax	$(13)	$(131)	$ (486)
Gain (loss) on disposal of discontinued businesses, after income tax	$ 16	$ 86	$ 64

Gain (Loss) on Disposal of Discontinued Businesses

	Year ended December 31,		
Subsidiary	2012	2011	2010
		(in millions)	
Red Oak and Ironwood	$ 73	$ —	$—
Eastern Energy	$ 30	$ —	$—
Tisza II	(87)	—	—
Carbon reduction projects	(6)	—	—
Brazil Telecom	6	446	—
Argentina distribution businesses	—	(338)	—
Wind projects	—	(22)	—
Barka	—	—	80
Lal Pir and Pak Gen	—	—	(22)
Ras Laffan	—	—	6
Gain (loss) on disposal, after income tax	$ 16	$ 86	$ 64

Tisza II—In December 2012, the Company completed the sale of its 100% ownership interest in Tisza II, a 900 MW gas/oil fired plant in Hungary. Net proceeds from the sale transaction were $14 million and the Company recognized a loss on disposal of $87 million, net of tax (including the realization of cumulative foreign currency translation loss of $73 million). In 2011 and 2010, the long-lived asset group of Tisza II was evaluated for impairment due to deteriorating economic and business conditions in Hungary, and was determined to be unrecoverable based on undiscounted cash flows. As a result, the Company had measured the asset group at fair value using discounted cash flows analysis and recognized asset impairment expense of $52 million and $85 million in 2011 and 2010, respectively, which is included in loss from operations of discontinued businesses above. Tisza II was reported in EMEA Generation segment.

Red Oak and Ironwood—In April 2012, the Company completed the sale of its 100%% interest in Red Oak, an 832 MW coal-fired plant in New Jersey, and Ironwood, a 710 MW coal-fired plant in Pennsylvania, for $228 million and recognized a gain of $73 million, net of tax. Both Red Oak and Ironwood were reported in the US Generation segment.

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 the realization of cumulative foreign currency translation loss of $208 million). These businesses were previously reported in "Corporate and Other".

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 Brazil 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 EMEA generation reportable segment.

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 operated 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. In December 2011, AEE along with certain of its affiliates filed for bankruptcy protection and was recorded as a cost method investment. In December 2012, the AEE bankruptcy proceedings were finalized and a gain of $30 million, net of tax, was recognized in gain on disposal of discontinued businesses. AEE was previously reported in the US 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. In November 2011, Borsod filed for liquidation and was recorded as a cost method investment. Borsod was previously reported in the EMEA Generation reportable 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 had filed for liquidation in February 2011, and was recorded as a cost method investment with the historical operating results reflected in discontinued operations. Thames was previously reported in the US Generation reportable 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 reportable 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 $22 million, net of tax, during the year ended December 31, 2010. These businesses were previously reported in the Asia Generation reportable 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 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 reportable segment.

24. ACQUISITIONS AND DISPOSITIONS

Acquisitions

DPL—On November 28, 2011, AES completed the acquisition of 100% of the common stock of DPL Inc. ("DPL"), the parent company of The Dayton Power and Light Company ("DP&L"), a utility based in Ohio, for approximately $3.5 billion, 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 beginning November 28, 2011 have been included in the Consolidated Statement of Operations with no comparable amounts for 2010. DPL's net assets acquired and liabilities assumed in the acquisition have been included in the Consolidated Balance Sheet as of December 31, 2011. The purchase price allocation was finalized in the third quarter of 2012 and the resulting adjustments to the preliminary purchase price allocation (recorded as of the acquisition date) have been retrospectively reflected as of December 31, 2011 in the accompanying Consolidated Balance Sheet. The effect of these adjustments on net income for the period November 28, 2011 through December 31, 2011 was not material. The preliminary purchase allocation, the measurement period adjustments, and the final purchase price allocation are presented in the table below:

	Preliminary	Measurement Period Adjustments	Final
		(in millions)	
Cash	$ 116	$—	$ 116
Accounts receivable	278	—	278
Inventory	124	—	124
Other current assets	41	—	41
Property, plant and equipment	2,549	(71)[(1)]	2,478
Intangible assets subject to amortization	166	(19)[(2)]	147
Intangible assets—indefinite-lived	5	—	5
Regulatory assets	201	16[(3)]	217
Other noncurrent assets	58	—	58
Current liabilities	(401)	(5)	(406)
Non-recourse debt	(1,255)	—	(1,255)
Deferred income taxes	(558)	7[(4)]	(551)
Regulatory liabilities	(117)	—	(117)
Other noncurrent liabilities	(195)	(15)[(5)]	(210)
Redeemable preferred stock	(18)	—	(18)
Net identifiable assets acquired	994	(87)	907
Goodwill	2,489	87[(6)]	2,576
Net assets acquired	$ 3,483	$—	3,483

(1) Represents net adjustments resulting from the refined information associated with certain contractual arrangements, growth and ancillary revenue assumptions. There was a related decrease of $25 million in the provisionally recognized deferred tax liabilities.

(2) Represents net adjustments to certain customer contracts of DPLER and other intangible assets resulting from the refined market and contractual information obtained during the measurement period. There was a related decrease of $7 million in the provisionally recognized deferred tax liabilities.

(3) Represents net adjustments resulting from an assessment of overall deferred tax liabilities on regulated property, plant and equipment. There was a related increase of $21 million in the provisionally recognized deferred tax liabilities.

(4) Represents the net impact of adjustments to the purchase price allocation recognized during the measurement period, including a decrease of $12 million related to the unfavorable coal contract and an increase of $16 million as a result of the finalization of DPL Inc.'s standalone federal tax return.

(5) Primarily represents an increase of $29 million related to an unfavorable coal contract partially offset by a decrease of $13 million in income taxes payable as a result of the finalization of DPL Inc.'s standalone federal tax return.

(6) Represents the net impact of purchase price adjustments on goodwill during the measurement period.

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. The Company owned approximately 70.81% of AES Cartagena through this holding company structure, as well as 100% of a related operations and maintenance company. Net proceeds from the sale were approximately €172 million ($229 million) and during the first quarter of 2012, the Company recognized a pretax gain of $178 million on the transaction.

Under the terms of the sale agreement, the buyer, Electrabel International Holdings B.V. ("Electrabel"), a subsidiary of GDF SUEZ S.A. or "GDFS", has an option to purchase the Company's remaining 20% interest at a fixed price of €28 million ($37 million) during a five month period beginning March 2013. Of the total proceeds received, approximately $9 million was deferred and allocated to Electrabel's option to purchase the Company's remaining interest. In the fourth quarter of 2012, the Company received $9 million in dividends from its 20% ownership of AES Cartagena, of which $5 million was deferred and allocated to Electrabel's option to purchase the Company's remaining interest. 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 ($95 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. Due to the Company's expected continuing ownership interest extending beyond one year from the completion of the sale of its 80% interest, the prior period operating results of AES Cartagena have not been reclassified as discontinued operations.

InnoVent and St. Patrick—On June 28, 2012, the Company closed the sale of its equity interest in InnoVent and controlling interest in St. Patrick. Net proceeds from the sale transactions were $42 million. The prior period operating results of St. Patrick were not deemed material for reclassification to discontinued operations. See Note 21—*Impairment Expense* and Note 9—*Other Non-Operating Expense* for further information.

China—On September 6, 2012 and December 31, 2012, the Company completed the sale of its interest in equity method investments in China. These investments included coal-fired, hydropower and wind generation facilities accounted for under the equity method of accounting. Net proceeds from the sale were approximately $133 million and the Company recognized a pretax gain of $27 million on the transaction, which is reflected as a gain on sale of investment. See Note 9—*Other Non-Operating Expense* for further information.

25. 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, 2012			December 31, 2011			December 31, 2010		
	Income	Shares	$ per Share	Income	Shares	$ per Share	Income	Shares	$ per Share
BASIC EARNINGS PER SHARE									
Income (loss) from continuing operations attributable to The AES Corporation common stockholders	$(915)	755	$(1.21)	$492	778	$0.63	$496	769	$0.64
EFFECT OF DILUTIVE SECURITIES									
Convertible securities	—	—	—	—	—	—	—	—	—
Stock options	—	—	—	—	2	—	—	2	—
Restricted stock units	—	—	—	—	3	—	—	3	—
DILUTED EARNINGS PER SHARE	$(915)	755	$(1.21)	$492	783	$0.63	$496	774	$0.64

The calculation of diluted earnings per share excluded 7, 6 and 17 million options outstanding at December 31, 2012, 2011 and 2010, respectively, that could potentially dilute basic earnings per share in the future. These options were not included in the computation of diluted earnings per share because their exercise price exceeded the average market price during the related period.

The calculation of diluted earnings per share also excluded 1 million options outstanding at December 31, 2012, that could potentially dilute earnings per share in the future. These options were not included in the computation of diluted earnings per share for the year ended December 31, 2012 because their inclusion would be anti-dilutive given the loss from continuing operations in the period. Had the Company generated income from continuing operations in the year ended December 31, 2012, 1 million of potential common shares of common stock related to the options would have been included in diluted average shares outstanding.

The calculation of diluted earnings per share also excluded 1 million restricted stock units outstanding at December 31, 2012, that could potentially dilute basic earnings per share in the future. These restricted stock units were not included in the computation of diluted earnings per share because the average amount of compensation cost per share attributed to future service and not yet recognized exceeded the average market price during the related period and thus to include the restricted units would have been anti-dilutive. The calculation of diluted earnings per share also excluded 6 million restricted stock units outstanding at December 31, 2012, that could potentially dilute earnings per share in the future. These restricted units were not included in the computation of diluted earnings per share for the year ended December 31, 2012, because their impact would be anti-dilutive given the loss from continuing operations. Had the Company generated income from continuing operations in the year ended December 31, 2012, 4 million of potential common shares of common stock related to the restricted stock units would have been included in diluted average shares outstanding.

For the years ended December 31, 2012, 2011 and 2010 all convertible debentures were omitted from the earnings per share calculation because they were anti-dilutive.

During the twelve months ended December 31, 2012, 1 million shares of common stock were issued under the Company's profit sharing plan and 2 million shares of common stock were issued upon the exercise of stock options.

26. 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 17—*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, 2012, the Company had $2.0 billion of unrestricted cash and cash equivalents.

During 2012, approximately 79% of our revenue, and 38% 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, the Philippine peso, the Kazakhstan Tenge, and the Cameroonian Franc 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 2012, 2011 or 2010.

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.

27. RELATED PARTY TRANSACTIONS

Certain of our businesses in Panama, the Dominican Republic, Kazakhstan and Cameroon are partially owned by governments either directly or through state-owned institutions. In the ordinary course of business, these businesses enter into energy purchase and sale transactions, and transmission agreements with other state-owned institutions which are controlled by such governments. At two of our generation businesses in Mexico, the offtakers exercise significant influence, but not control, through representation on these businesses' Board of Directors. These offtakers are also required to hold a nominal ownership interest in such businesses. In Chile, we provide capacity and energy under contractual arrangements to our investments which are accounted for under the equity method of accounting. Additionally, the Company provides certain support and management services to several of its affiliates under various agreements. The Company's Consolidated Statements of Operations included the following transactions with related parties for the years indicated:

	Years Ended December 31,		
	2012	2011	2010
		(in millions)	
Revenue—Non-Regulated	$926	$736	$686
Revenue—Regulated	37	39	26
Cost of Sale—Non-Regulated	63	77	36
Interest expense	8	4	2
Other income	4	6	—

The following table summarizes the balances receivable from and payable to related parties included in the Company's Consolidated Balance Sheets as of December 31, 2012 and 2011:

	2012	2011
	(in millions)	
Receivables from related parties	$178	$164
Payables to related parties	7	12

During 2011, the Company sold 19% of its interest in Mong Duong to Stable Investment Corporation, a subsidiary of China Investment Corporation. Terrific Investment Corporation, also a subsidiary of China Investment Corporation, owns approximately 15% of the Company's outstanding shares of common stock and has representation on the Company's Board of Directors.

28. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Quarterly Financial Data

The following tables summarize the unaudited quarterly statements of operations for the Company for 2012 and 2011. 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 2012			
	Mar 31	June 30	Sept 30	Dec 31
	(in millions, except per share data)			
Revenue	$4,722	$4,192	$ 4,587	$4,640
Gross margin	1,082	695	1,006	931
Income from continuing operations, net of tax[1]	524	139	(1,400)	377
Discontinued operations, net of tax	(9)	68	(2)	(54)
Net income (loss)	$ 515	$ 207	$(1,402)	$ 323
Net income (loss) attributable to The AES Corporation	$ 341	$ 140	$(1,568)	$ 175
Basic income (loss) per share:				
Income from continuing operations attributable to The AES Corporation, net of tax	$ 0.46	$ 0.09	$ (2.10)	$ 0.31
Discontinued operations attributable to The AES Corporation, net of tax	(0.01)	0.09	—	(0.08)
Basic income (loss) per share attributable to The AES Corporation	$ 0.45	$ 0.18	$ (2.10)	$ 0.23
Diluted income (loss) per share:				
Income from continuing operations attributable to The AES Corporation, net of tax	$ 0.45	$ 0.09	$ (2.10)	$ 0.31
Discontinued operations attributable to The AES Corporation, net of tax	(0.01)	0.09	—	(0.08)
Diluted income (loss) per share attributable to The AES Corporation	$ 0.44	$ 0.18	$ (2.10)	$ 0.23
Dividends declared per common share	$ —	$ —	$ 0.04	$ 0.04

	Quarter Ended 2011			
	Mar 31	June 30	Sept 30	Dec 31[2]
	(in millions, except per share data)			
Revenue	$4,102	$4,386	$4,252	$4,183
Gross margin	985	989	1,010	1,079
Income from continuing operations, net of tax[3]	482	430	210	453
Discontinued operations, net of tax	1	(3)	(35)	(8)
Net income	$ 483	$ 427	$ 175	$ 445
Net income (loss) attributable to The AES Corporation	$ 224	$ 174	$ (131)	$ (209)
Basic income (loss) per share:				
Income (loss) from continuing operations attributable to The AES Corporation, net of tax	$ 0.29	$ 0.24	$ (0.08)	$ 0.18
Discontinued operations attributable to The AES Corporation, net of tax	(0.01)	(0.02)	(0.09)	(0.45)
Basic income (loss) per share attributable to The AES Corporation	$ 0.28	$ 0.22	$ (0.17)	$ (0.27)
Diluted income (loss) per share:				
Income (loss) from continuing operations attributable to The AES Corporation, net of tax	$ 0.29	$ 0.24	$ (0.08)	$ 0.18
Discontinued operations attributable to The AES Corporation, net of tax	(0.01)	(0.02)	(0.09)	(0.45)
Diluted income (loss) per share attributable to The AES Corporation	$ 0.28	$ 0.22	$ (0.17)	$ (0.27)
Dividends declared per common share	$ —	$ —	$ —	$ —

(1) Includes pretax impairment expense of $10 million, $18 million, $1.89 billion and $(31) million, for the first, second, third and fourth quarters of 2012, respectively. See Note 21—*Impairment Expense* and Note 10—*Goodwill and Other Intangible Assets* for further discussion.

(2) 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 24—*Acquisitions and Dispositions* for further discussion.

(3) Includes pretax impairment expense of $33 million, $147 million and $10 million, for the second, third and fourth quarters of 2011, respectively. See Note 21—*Impairment Expense* and Note 10—*Goodwill and Other Intangible Assets* for further discussion.

29. SUBSEQUENT EVENTS

Beaver Valley PPA termination—On January 1, 2013, Beaver Valley, a wholly-owned 125 MW coal-fired plant in Pennsylvania, entered into an agreement to terminate its PPA with the offtaker in exchange for a lump sum payment of $60 million which was received on January 9, 2013. The termination was effective January 8, 2013. Beaver Valley also terminated its fuel supply agreement. Under the PPA termination agreement, annual capacity agreements between the off-taker and PJM Interconnection, LLC (a regional transmission organization) for 2013—2016 period have been assigned to Beaver Valley. As of December 31, 2012, Beaver Valley had long-lived assets of $47 million, which may incur asset impairment expense in future periods due to the elimination of payments under the terminated PPA.

Masinloc refinancing—On January 23, 2013, Masinloc, a 660 MW coal-fired power plant in the Philippines, completed the refinancing of its $500 million senior debt facility with a consortium of local banks. The refinancing allowed us to improve interest rates, extend the term of the financing and relax certain restrictive covenants. As a result, the Company expects to recognize a loss on extinguishment of debt in the range of $39 million to $43 million in first quarter of 2013 primarily related to prepayment penalties.

Ukraine Utilities sale—On January 29, 2013, the Company agreed to sell its two power distribution businesses in Ukraine to VS Energy International for $113 million subject to customary working capital adjustments. Under the agreement, the Company will sell its 89.1% equity interest in AES Kyivoblenergo, which serves 881,000 customers in the Kiev region, and its 84.6% percent equity interest in AES Rivneoblenergo, which serves 412,000 customers in the Rivne region. As of December 31, 2012, these businesses had a carrying amount of approximately $131 million (including a cumulative foreign currency translation loss of $34 million). The Company expects to recognize an impairment loss in the range of $20 million to $26 million, net of transaction costs, upon meeting the held for sale criteria in the first quarter of 2013. The transaction is expected to close by the second quarter of 2013 and is subject to regulatory approval.

Bulgaria political and economic conditions—In February 2013, following protests over Bulgaria's electricity prices and other economic issues, the Prime Minister announced plans to reduce electricity tariffs by 8% from March 1, 2013, subject to the approval of the Bulgaria's State Commission for Energy and Water Regulation. The announcement did not specify how this reduction was to be structured or financed. Following the announcement, the Prime Minister and his government resigned. It is not certain whether the new government will implement the tariff reduction. The ultimate impact of actions by the new government of Bulgaria, if any, are unknown, however it is possible that these developments may result in indicators of impairment of the Company's long-lived assets in Bulgaria. As of December 31, 2012, the Company had long-lived assets in Bulgaria of $1.8 billion and net equity was approximately $517 million. Revenue and adjusted pre-tax contribution for the year ended December 31, 2012 totaled approximately $369 million and $102 million, respectively.

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, 2012, our disclosure controls and procedures were effective.

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, 2012. 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, 2012.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2012, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which appears herein.

Changes in Internal Control Over Financial Reporting:

There were no changes that occurred during the quarter ended December 31, 2012 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, 2012 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.

In our opinion, The AES Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, 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, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2012 of The AES Corporation and our report dated February 26, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

McLean, Virginia
February 26, 2013

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 2013 Annual Meeting of Stock Holders which the Registrant expects will be filed on or around March 4, 2013 (the "2013 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 2013 Proxy Statement and is herein incorporated by reference.

ITEM 11. EXECUTIVE COMPENSATION

The following information is contained in the 2013 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 2013 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 2013 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, 2012:

Securities Authorized for Issuance under Equity Compensation Plans (As of December 31, 2012)

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(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]	15,842,741 [2]	$14.92	16,245,113
Equity compensation plans not approved by security holders[3]	10,064	$ 4.05	—
Total	15,852,805	$14.91	16,245,113

(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 $15.21 (excluding PSU and RSU awards), with 16,245,113 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 $3.19. 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 5,405,235 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 $11.21. 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 2,035,543 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 $35.44. 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 24,354,930 shares are not included in Column (c) above.

(2) Includes 6,806,948 (of which 3,027,981 are vested and 3,629,523 are unvested) shares underlying PSU and RSU awards (assuming performance at a maximum level), 1,162,552 shares underlying Director stock unit awards, and 7,873,241 shares issuable upon the exercise of Stock Option grants, for an aggregate number of 15,842,741 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 $4.05. 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 7,107,448 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, 2012, 4 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. 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 2013 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 2013 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, as amended and restated, on February 17, 2012 (filed herewith).
10.6	The AES Corporation Stock Option Plan for Outside Directors, as amended and restated, on December 7, 2007 (filed herewith).
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 is incorporated herein by reference to Exhibit 10.14 of the Company's Form 10-K for the year ended December 31, 2011.
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 is incorporated by reference to Exhibit 10.16 of the Company's Form 10-K for the year ended December 31, 2011.
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.
10.17A	Amendment to The AES Corporation Restoration Supplemental Retirement Plan, dated December 9, 2011 (filed herewith).

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.
10.18A	Amendment to The AES Corporation International Retirement Plan, dated December 9, 2011 (filed herewith).
10.19	The AES Corporation Severance Plan, as amended and restated on October 28, 2011is incorporated herein by reference to Exhibit 10.19 of the Company's Form 10-K for the year ended December 31, 2011.
10.20	The AES Corporation Amended and Restated Executive Severance Plan dated August 1, 2012 is incorporated herein by reference to Exhibit 10.2 of the Company's Form 10-Q for the period ended June 30, 2012.
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 is incorporated herein by reference to Exhibit 10.22 of the Company's Form 10-K filed on December 31, 2011.
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	Separation Agreement, dated April 27, 2012, between the Company and Victoria D. Harker is incorporated by reference to Exhibit 10.1 of the Company's Form 10-Q for the period ended June 30, 2012.
10.29	Separation Agreement, dated November 19, 2012 between the Company and Edward C. Hall, III (filed herewith).
10.30	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.

10.30A 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.

10.30B 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.

10.30C 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.

10.30D Amendment No.1 to and Waiver Under the Fifth Amended and Restated Credit and Reimbursement Agreement dated January 13, 2012 is incorporated herein by reference to Exhibit 10.28D of the Company's Form 10-K for the period ending December 31, 2012.

10.30E Amendment No.2 to the Fifth Amended and Restated Credit and Reimbursement Agreement dated January 2, 2012 (filed herewith).

10.31 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).

10.32 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).

10.33 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).

10.34 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.

10.35 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.

10.36 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.

10.37 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 Thomas M. O'Flynn (filed herewith).
32.1	Section 1350 Certification of Andrés Gluski (filed herewith).
32.2	Section 1350 Certification of Thomas M. O'Flynn (filed herewith).
101.INS	XBRL Instance Document (filed herewith).
101.SCH	XBRL Taxonomy Extension Schema Document (filed herewith).
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document (filed herewith).
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document (filed herewith).
101.LAB	XBRL Taxonomy Extension Label Linkbase Document (filed herewith).
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document (filed herewith).

(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 26, 2013

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 26, 2013
* **Zhang Guobao**	Director	February 26, 2013
* **Kristina Johnson**	Director	February 26, 2013
* **Tarun Khanna**	Director	February 26, 2013
* **John A. Koskinen**	Director	February 26, 2013
* **Philip Lader**	Director	February 26, 2013
* **John B. Morse**	Director	February 26, 2013
* **Sandra O. Moose**	Director	February 26, 2013
* **Philip A. Odeen**	Chairman of the Board and Lead Independent Director	February 26, 2013
* **Charles O. Rossotti**	Director	February 26, 2013
* **Sven Sandstrom**	Director	February 26, 2013
/s/ THOMAS M. O'FLYNN **Thomas M. O'Flynn**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2013
/s/ MARY E. WOOD **Mary E. Wood**	Vice President and Controller (Principal Accounting Officer)	February 26, 2013

*By: /s/ BRIAN A. MILLER
Attorney-in-fact

February 26, 2013

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.

See Notes to Schedule I

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF PARENT
BALANCE SHEETS

	December 31, 2012	December 31, 2011
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 305	$ 189
Restricted cash	227	50
Accounts and notes receivable from subsidiaries	594	602
Deferred income taxes	8	24
Prepaid expenses and other current assets	28	43
Total current assets	1,162	908
Investment in and advances to subsidiaries and affiliates	9,393	11,352
Office Equipment:		
Cost	86	81
Accumulated depreciation	(72)	(67)
Office equipment, net	14	14
Other Assets:		
Deferred financing costs (net of accumulated amortization of $58 and $74, respectively)	76	92
Deferred income taxes	573	525
Debt service reserves and other deposits	—	222
Total other assets	649	839
Total	$11,218	$13,113
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable	$ 15	$ 21
Accounts and notes payable to subsidiaries	50	48
Accrued and other liabilities	241	216
Senior notes payable—current portion	11	305
Total current liabilities	317	590
Long-term Liabilities:		
Senior notes payable	5,434	5,663
Junior subordinated notes and debentures payable	517	517
Accounts and notes payable to subsidiaries	242	254
Other long-term liabilities	139	143
Total long-term liabilities	6,332	6,577
Stockholders' equity:		
Common stock	8	8
Additional paid-in capital	8,525	8,507
Retained earnings (accumulated deficit)	(264)	678
Accumulated other comprehensive loss	(2,920)	(2,758)
Treasury stock	(780)	(489)
Total stockholders' equity	4,569	5,946
Total	$11,218	$13,113

See Notes to Schedule I

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF OPERATIONS

	For the Years Ended December 31		
	2012	2011	2010
	(in millions)		
Revenue from subsidiaries and affiliates	$ 20	$ 59	$ 34
Equity in earnings (loss) of subsidiaries and affiliates	(437)	352	590
Interest income	119	158	279
General and administrative expenses	(133)	(241)	(261)
Interest expense	(502)	(444)	(461)
Income (loss) before income taxes	(933)	(116)	181
Income tax benefit (expense)	21	174	(172)
Net income (loss)	$(912)	$ 58	$ 9

See Notes to Schedule I

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF COMPREHENSIVE INCOME
YEARS ENDED DECEMBER 31, 2012, 2011, AND 2010

	2012	2011	2010
		(in millions)	
NET INCOME (LOSS)	$ (912)	$ 58	$ 9
Available-for-sale securities activity:			
Change in fair value of available-for-sale securities, net of income tax (expense) benefit of $0, $0 and $3, respectively	1	1	(5)
Reclassification to earnings, net of income tax (expense) benefit of $0, $0 and $0, respectively	(1)	(2)	—
Total change in fair value of available-for-sale securities	—	(1)	(5)
Foreign currency translation activity:			
Foreign currency translation adjustments, net of income tax (expense) benefit of $0, $18 and $(11), respectively	(127)	(297)	383
Reclassification to earnings, net of income tax (expense) benefit of $0, $0 and $0, respectively	37	154	103
Total foreign currency translation adjustments, net of tax	(90)	(143)	486
Derivative activity:			
Change in derivative fair value, net of income tax (expense) benefit of $33, $95 and $37, respectively	(108)	(311)	(252)
Reclassification to earnings, net of income tax (expense) benefit of $(51), $(21) and $(20), respectively	161	121	172
Total change in fair value of derivatives, net of tax	53	(190)	(80)
Pension activity:			
Prior service cost for the period, net of tax	(1)	—	—
Net actuarial (loss) for the period, net of income tax (expense) benefit of $64, $25 and $23, respectively	(130)	(43)	(23)
Amortization of net actuarial loss, net of income tax (expense) benefit of $(5), $(1) and $(12), respectively	6	2	1
Total change in unfunded pension obligation	(125)	(41)	(22)
OTHER COMPREHENSIVE INCOME (LOSS)	(162)	(375)	379
COMPREHENSIVE INCOME (LOSS)	$(1,074)	$(317)	$ 388

See Notes to Schedule I

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
	2012	2011	2010
		(in millions)	
Net cash provided by operating activities	$ 694	$ 719	$ 488
Investing Activities:			
Investment in and advances to subsidiaries	(168)	(2,655)	(1,185)
Return of capital	660	304	300
(Increase) decrease in restricted cash	44	(261)	(2)
Additions to property, plant and equipment	(24)	(28)	(22)
(Purchase) sale of short term investments, net	1	2	(3)
Net cash used in investing activities	513	(2,638)	(912)
Financing Activities:			
Borrowings (payments) under the revolver, net	(295)	295	—
Borrowings of notes payable and other coupon bearing securities	—	2,050	—
Repayments of notes payable and other coupon bearing securities	(236)	(477)	(914)
Loans (to) from subsidiaries	(236)	(5)	(154)
Purchase of treasury stock	(301)	(279)	(99)
Proceeds from issuance of common stock	8	3	1,569
Common stock dividends paid	(30)	—	—
Payments for deferred financing costs	(1)	(75)	(12)
Net cash provided by financing activities	(1,091)	1,512	390
Increase (decrease) in cash and cash equivalents	116	(405)	(34)
Cash and cash equivalents, beginning	189	594	628
Cash and cash equivalents, ending	$ 305	$ 189	$ 594
Supplemental Disclosures:			
Cash payments for interest, net of amounts capitalized	$ 479	$ 392	$ 412
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

The Schedule I Condensed Financial Information of the Parent includes the accounts of The AES Corporation (the "Parent Company") and certain holding companies.

Accounting for Subsidiaries and Affiliates—The Parent Company has accounted for the earnings of its subsidiaries on the equity method in the financial information.

Income Taxes—Positions taken on the Parent Company's income tax return which satisfy a more-likely-than-not threshold will be recognized in the financial statements. The income tax expense or benefit computed for the Parent Company reflects the tax assets and liabilities 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—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.

Correction of an Error—Certain amounts due to or from subsidiaries were not properly eliminated in the preparation of the Schedule I Condensed Financial Information of Parent for the year ended December 31, 2011 included in the Company's 2011 Form 10-K. As a result, the December 31, 2011 balance sheet information of accounts and notes receivable from subsidiaries, investments in and advances to subsidiaries and affiliates, and current and long-term accounts and notes payable to subsidiaries were overstated. Accounts and notes receivable from subsidiaries was previously reported as $871 million and has been restated to $602 million. Investment in and advances to subsidiaries and affiliates was previously reported as $12,088 million and has been restated to $11,352 million. Accounts and notes payable to subsidiaries was previously reported as $317 million and has been restated to $48 million. Accounts and notes payable to subsidiaries was previously reported as $1,007 million and has been restated to $254 million.

Net cash provided by operating activities previously reported on the statement of cash flows for the year ended December 31, 2011 was previously reported as $1,569 million and has now been restated to $719 million. Net cash used in investing activities was previously reported as $2,747 million and has now been restated to $2,638 million. Net cash provided by financing activities previously reported as $773 million was restated to $1,512 million.

Interest income and interest expense previously reported on the statement of operations for the year ended December 31, 2011 were each reduced by approximately $50 million as a result of these adjustments. There was no impact to Parent Company net income.

There was no impact to the Schedule 1 Condensed Financial Information of Parent for the twelve months ended December 31, 2010 or the statement of comprehensive income for the year ended December 31, 2011 as a result of these adjustments. Further, there was no impact to the Company's consolidated financial statements for 2012, 2011 or 2010 as a result of these adjustments.

Selected Balance Sheet Data:

	December 31, 2012	December 31, 2011
	(in millions)	
Assets		
Investment in and advances to subsidiaries and affiliates	$ 9,393	$11,352
Deferred income taxes—long term	$ 573	$ 525
Total other assets	$ 649	$ 839
Total assets	$11,218	$13,113
Liabilities and Stockholders' Equity		
Other long-term liabilities	$ 139	$ 143
Total long-term liabilities	$ 6,332	$ 6,577
Additional paid-in capital	$ 8,525	$ 8,507
Retained earnings (accumulated deficit)	$ (264)	$ 678
Accumulated other comprehensive loss	$ (2,920)	$ (2,758)
Total stockholders' equity	$ 4,569	$ 5,946
Total liabilities and stockholders' equity	$11,218	$13,113

Selected Operations Data:

	For the Year Ended December 31,		
	2012	2011	2010
	(in millions)		
Equity in earnings (loss) of subsidiaries and affiliates	$(437)	$ 352	$ 590
Income (loss) before income taxes	$(933)	$(116)	$ 181
Income tax benefit (expense)	$ 21	$ 174	$(172)
Net income (loss) attributable to The AES Corporation	$(912)	$ 58	$ 9

2. Senior Notes and Junior Subordinated Notes and Debentures Payable

	Interest Rate	Maturity	December 31, 2012	December 31, 2011
			(in millions)	
Senior Unsecured Note	7.75%	2014	$ 500	$ 500
Revolving Loan under Senior Secured Credit Facility	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	807	1,042
Senior Unsecured Note	8.00%	2020	625	625
Senior Unsecured Note	7.38%	2021	1,000	1,000
Term Convertible Trust Securities	6.75%	2029	517	517
Unamortized discounts			(22)	(29)
SUBTOTAL			5,962	6,485
Less: Current maturities			(11)	(305)
Total			$5,951	$6,180

FUTURE MATURITIES OF DEBT—Recourse debt as of December 31, 2012 is scheduled to reach maturity as set forth in the table below:

December 31,	Annual Maturities
	(in millions)
2013	$ 11
2014	510
2015	511
2016	527
2017	1,510
Thereafter	2,893
Total debt	$5,962

3. Dividends from Subsidiaries and Affiliates

Cash dividends received from consolidated subsidiaries and from affiliates accounted for by the equity method were as follows:

	2012	2011	2010
		(in millions)	
Subsidiaries	$1,049	$1,059	$944
Affiliates	$ 5	$ 25	$ 10

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, 2012, by the terms of the agreements, to an aggregate of approximately $568 million representing 19 agreements with individual exposures ranging from less than $1 million up to $237 million.

LETTERS OF CREDIT—At December 31, 2012, the Company had $5 million in letters of credit outstanding under the senior unsecured credit facility representing 6 agreements with individual exposures ranging from less than $1 million and up to $2 million, which operate to guarantee performance relating to certain project development and construction activities and subsidiary operations. At December 31, 2012, the Company had $215 million in cash collateralized letters of credit outstanding representing 9 agreements with individual exposures ranging from less than $1 million up to $189 million, which operate to guarantee performance relating to certain project development and construction activities and subsidiary operations. During 2012, 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, 2010	$276	$ 53	$(37)	$ 3	$295
Year ended December 31, 2011	295	43	(41)	(24)	273
Year ended December 31, 2012	273	129	(80)	(13)	309

AES Executive Leadership Team

Andrés Gluski
President and Chief Executive Officer

Brian Miller
Executive Vice President, General Counsel & Corporate Secretary

Thomas O'Flynn
Executive Vice President, Chief Financial Officer

Andrew Vesey
Executive Vice President, Chief Operating Officer

Elizabeth Hackenson
Senior Vice President, Chief Information Officer and Global Business Services

AES Board of Directors

Philip Odeen (Chairman)
Former Non-Executive Chairman, Convergys Corporation; former Chairman, Avaya Inc, Reynolds and Reynolds Company, and TRW Inc.; former President and Chief Executive Officer, BDM

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 Hydro, LLC; 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 Advisor 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); former 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; 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

AES LISTED NYSE

Stock Information
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, 2012 there were approximately 6,727 AES shareholders of record and 744,263,855 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, issues related to dividend checks, address changes, name changes and stock transfers.

By mail and overnight delivery:
Computershare Investor Services
250 Royall Street
Canton, MA 02021
877-373-6374
www.computershare.com

Independent Auditors
Ernst & Young LLP

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 invest@aes.com
Ahmed Pasha, Vice President, Investor Relations: 703-682-6451

Media Inquiries
General: 703-682-1262 or media@aes.com
Rich Bulger, Vice President, External Communications: 703-682-6318

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.

The AES Corporation
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www.aes.com

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