AES CORP
Form 10-K
February 27, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x **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

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 x 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 x

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

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

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

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

The 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

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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, collectivel 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;

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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.

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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.

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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.

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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.

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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;

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- 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.

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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

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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		

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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

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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-

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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.

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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.

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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

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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

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(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.

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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.

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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		

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(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:

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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

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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.

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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

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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		

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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%).

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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.

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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.

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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.

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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

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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).

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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.

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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.

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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.

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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

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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.

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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.

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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

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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

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(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.

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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).

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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.

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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.

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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

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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 c