AES CORP
Form 10-K
May 23, 2007

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, 2006

-OR-

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

COMMISSION FILE NUMBER 0-19281

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 o No x

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 o 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 o No x

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. o

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

Large accelerated filer x Accelerated filer o Non-accelerated filer o

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates on June 30, 2006, the last business day after the Registrant s most recently completed second fiscal quarter (based on the closing sale price of $18.45 of the Registrant s Common Stock, as reported by the New York Stock Exchange on such date) was approximately $12.137 billion.

The number of shares outstanding of the Registrant s Common Stock, par value $0.01 per share, on May 15, 2007, was 667,582,977.

THE AES CORPORATION
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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 refers only to the parent, publicly- held holding company, The AES Corporation, excluding its subsidiaries and affiliates.

FORWARD-LOOKING INFORMATION

In this filing and from time to time, 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:

- our ability to achieve expected rate increases in our Utility businesses;

- our ability to manage our operation and maintenance costs;

- the performance and reliability of our generating plants, including our ability to reduce unscheduled down-times;

- 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 our ability to hedge our exposure to such market price risk;

- changes in the prices and availability of coal, gas and other fuels and 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 those affecting the availability and cost of capital in order to refinance existing debt and finance capital expenditures, acquisitions, investments and other corporate purposes;

- 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;

- changes in inflation, interest rates and foreign currency exchange rates;

- our ability to purchase and sell assets at attractive prices and on other attractive terms;

- 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;

- the expropriation or nationalization of our businesses or assets by foreign governments, whether with or without adequate compensation;

- changes in laws, rules and regulations affecting our 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 (FERC), changes in law resulting from new federal energy legislation, including the effects of the repeal of Public Utility

Holding

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Company Act (PUHCA), and changes in political or regulatory oversight or incentives affecting our alternative energy businesses, including tax incentives;

- changes in environmental, tax and other laws, including requirements for reduced emissions of sulfur nitrogen, carbon, mercury, and other substances;

- the economic climate, particularly the state of the economy in the areas in which we operate;

- variations in weather, especially mild winters and cooler summers in the areas in which we operate, and the occurrence of hurricanes and other storms and disasters;

- our ability to meet our expectations in the development, construction, operation and performance of our alternative energy businesses, which rely, in part, on actual wind volumes in areas affecting our existing and planned wind farms performing consistently with our expectations, and actual wind turbine performance operating consistently with our expectations, the continued attractiveness of market prices for carbon offsets under markets governed by the Kyoto Protocol, and consistent and orderly regulatory procedures governing the application, regulation, issuance of Certified Emission Reduction (CER) credits and the extension of such regulations beyond 2012;

- our ability to keep up with advances in technology;

- the potential effects of threatened or actual acts of terrorism and war;

- changes in tax laws and the effects of our strategies to reduce tax payments;

- the effects of litigation and government investigations;

- changes in accounting standards, corporate governance and securities law requirements;

- our ability to remediate and compensate for the material weaknesses in our internal controls over financial reporting; and

- 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 United States Generally Accepted Accounting Principles (GAAP).

Except to the extent required by the federal securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

Restatement Of Consolidated Financial Statements

Background

The Company has previously identified certain material weaknesses related to its system of internal control over financial reporting. These material weaknesses, as described in the Company s previously filed Form 10-K for the year ended December 31, 2005 included the following general areas:

- Aggregation of control deficiencies at our Cameroonian subsidiary;

- Lack of U.S. GAAP expertise in Brazilian businesses;

- Treatment of intercompany loans denominated in other than the functional currency;
- Derivative accounting; and
- Income taxes.

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In part, the continuing remediation of these material weaknesses resulted in the identification of certain material financial statement errors. The Company has restated its financial statements for years ended prior to December 31, 2005 on March 30, 2005, January 19, 2006 and April 4, 2006 largely as a result of material weaknesses. As part of the Company s plan to eliminate these material weaknesses in internal control over financial reporting, the Company has embarked on a program, over a several year period, to improve the quality of its people, processes and financial systems. This has included a broad restructuring of the global finance organization to operate on a more centralized basis and the recruitment of additional accounting, financial reporting, income tax, internal control and internal audit staff around the world.

During the fourth quarter of 2006, in conjunction with these improvements, continued remediation of some of our material weaknesses and overall strengthening of controls across our businesses, the Company identified certain additional errors which required the restatement of previously issued consolidated financial statements for the years ended December 31, 2005 and December 31, 2004 and for the previously issued interim periods ending March 31, 2006, June 30, 2006 and September 30, 2006.

The Company s remediation efforts for certain material weaknesses reported as of December 31, 2005, as well as improvements to controls across the Company, resulted in the identification of errors included in the current restatement. In addition, a number of immaterial errors were identified as a result of the continued strengthening of the global finance organization. The Company believes that the increase in technical tax and accounting expertise, increased staffing levels at certain of our businesses and at our corporate office, and a focused effort on increasing the number of financial audit activities have contributed to the overall improvement of the accuracy of our financial statements. It also resulted in the identification of material weaknesses in areas not previously reported, although not all weaknesses contributed to the need to restate the consolidated financial statements. For further discussion of our material weaknesses, see Item 9A of this Annual Report on Form 10-K.

The restatement adjustments resulted in a decrease to previously reported income from continuing operations and net income of $24 million for the year ended December 31, 2005 and an increase of $2 million for the year ended December 31, 2004. It also resulted in a decrease to previously reported income from continuing operations and net income of $3 million for the three months ending March 31, 2006, an increase to net income of $10 million for the six months ending June 30, 2006 and an increase to net income of $30 million for the nine months ending September 30, 2006. These interim period adjustments for the first three quarters of 2006 were largely the result of reversing errors previously corrected in these periods, which were not previously considered material either to the period in which they were corrected or the prior period to which they actually arose. Additionally, the cumulative adjustment for all periods prior to 2004 resulted in an increase to retained deficit of $50 million.

The following table quantifies the net impact of the restatement corrections by key income statement line items for the years ended December 31, 2005 and 2004 and includes the resulting impact on diluted earnings per share from continuing operations. The primary line items affected include revenue, cost of sales, gain (loss) on foreign currency transactions, income tax expense and the related impacts on minority interest expense.

	Year Ended December 31, 2005	2004
	(in millions, except per share amounts)	
Income from continuing operations as previously reported	$ 598	$ 266
Changes in income from continuing operations from restatement due to:		
Increase in revenue	25	1
Decrease in cost of sales	5	18
(Increase) decrease in general and administrative expense	(4)	1
Increase in other income	11	1
(Increase) in goodwill and asset impairment expense	(6)	(1)
(Increase) decrease in foreign currency transaction losses	(13)	27
Decrease in equity earnings of affiliates	(6)	(7)
(Increase) in income tax expense	(27)	(24)
(Increase) in minority interest and other(1)	(9)	(14)
(Decrease) increase in income from continuing operations	(24)	2
Income from continuing operations as restated	$ 574	$ 268
Diluted earnings per share from continuing operations as previously reported	$ 0.90	$ 0.41
Changes due to restatement effects	(0.03)	
Diluted earnings per share from continuing operations as restated	$ 0.87	$ 0.41
Diluted shares outstanding	664.6	648.1

(1) Minority interest and other includes $12 million and $13 million of minority interest expense for the periods ending December 31, 2005 and December 31, 2004, respectively, related to the impact of the restatement adjustments at entities with minority interests.

The Company has been cooperating with an informal inquiry by the Staff of the Securities Exchange Commission (SEC) concerning the Company s restatements and related matters, and has been providing information and documents to the SEC Staff on a voluntary basis. Because the Company is unable to predict the outcome of this inquiry and the SEC Staff may disagree with the manner in which the Company has accounted for and reported the financial impact of the adjustments to previously filed financial statements, there may be a risk that the inquiry by the SEC could lead to circumstances in which the Company may have to further restate previously filed financial statements, amend prior filings or take other actions not currently contemplated.

The restatement adjustments include several key categories as described below:

Brazil Adjustments

Prior year errors related to certain subsidiaries in Brazil include the following:

- decrease of the U.S. GAAP fixed asset basis and related depreciation at Eletropaulo of $21 million in 2005 and $16 million in 2004 (the impact net of tax and minority interest is $4 million in 2005 and $4 million in 2004); and

- other errors identified through account reconciliation or review procedures.

The cumulative impact on net income was an increase of $6 million and $3 million for the years ended December 31, 2005 and 2004, respectively.

La Electricidad de Caracas (EDC)

Prior year errors related to the Company s Venezuelan subsidiary, EDC, include the following:

- $22 million revenue increase predominantly related to an error in updating the current tariff rates in the unbilled revenue calculation for 2005,

- $10 million increase in foreign currency transaction expense posted incorrectly to the balance sheet in 2005, and

- other errors identified through account reconciliation or review procedures.

The cumulative impact of all EDC adjustments on net income was an increase of $2 million for each of the years ended December 31, 2005 and 2004.

Capitalization of Certain Costs

Certain errors were discovered with fixed asset balances at several of the Company s facilities related to capitalization of development costs, overhead and capitalized interest. The cumulative impact on net income for capitalization errors was a decrease of $4 million for the year ended December 31, 2005 and a decrease of $2 million for the year ended December 31, 2004.

Derivatives

Adjustments were identified resulting from the detailed review of certain prior year contracts and include the following:

- the evaluation of hedge effectiveness; and

- the identification and evaluation of derivatives.

The most significant adjustment involved a power sales agreement signed in 2002 between the Company s generation facility in Cartagena, Spain, an unconsolidated subsidiary accounted for using the equity method of accounting, and its power offtaker. The power sales agreement had a pricing component that was tied to the U.S. dollar, although the entity s own functional currency was the Euro and that of the offtaker was the Euro. In addition, a maintenance service agreement related to the Cartagena facility included a pricing mechanism that was tied to changes in the U.S. dollar, when the entity s functional currency was the Euro and the service provider s functional currency was the Yen.

Under the guidance of Statement of Financial Accounting Standard (SFAS) No. 133,   Accounting for Derivative Instruments and Hedging Activities,   these contracts contained embedded derivatives that are required to be bifurcated from the contract and recorded at fair value with changes in fair value recognized in the results of operations. The net result of these adjustments was a decrease of $3 million and an increase of $4 million in equity in earnings of affilitates for the years ended December 31, 2005 and 2004, respectively.

The cumulative impact of all derivative adjustments on net income was a decrease of $4 million in 2005 and an increase of $5 million in 2004.

Income Tax Adjustments

Income tax adjustments relate primarily to the following:

- A $20 million adjustment to correct income tax expense in the fourth quarter of 2005 as a result of an incorrect 2004 tax return to accrual adjustment, previously disclosed in the Company s Form 10-Q for September 30, 2006; and

- A $21 million adjustment to record income tax benefit in 2004 as a result of a change in local income tax reporting for leases in Qatar, offset by adjustments to correct income tax expense for certain state deferred tax assets and other miscellaneous items.

The net impact of individual income tax adjustments resulted in an increase to income tax expense of approximately $18 million in 2005 and $7 million in 2004. The cumulative impact on income tax expense as a result of all restatement adjustments was an increase of approximately $27 million for the year ended December 31, 2005 and an increase of approximately $24 million for the year ended December 31, 2004.

Other Adjustments

As a result of work performed in the course of our year end closing process, certain other adjustments were identified which decreased net income by $6 million for the year ended December 31, 2005 and increased net income by $1 million for the year ended December 31, 2004.

Balance Sheet Adjustments

Adjustments at certain businesses in Brazil

The Company s Brazilian business, Sul, records customer receipts used to provide line extensions as an offset against property, plant and equipment. However, the regulatory body of Brazil never issued any guidance with respect to the treatment of these customer receipts. As such, we believe that a more appropriate classification of these customer receipts would have been as a regulatory liability given that the actual treatment as an offset against property, plant and equipment was never approved by the regulatory body of Brazil. Additionally, the regulatory liability treatment provides for the possibility of a future obligation back to the customers, which was confirmed by a recent regulatory ruling. The increase to property, plant and equipment and increase to long-term regulatory liabilities was $93 million and $62 million at December 31, 2005 and 2004, respectively.

Cartagena Deconsolidation

Upon the Company s adoption of Financial Interpretation No.46, Variable Interest Entities (FIN No. 46R), as of January 1, 2004, the Company incorrectly continued to consolidate our business in Cartagena, Spain. An adjustment was made to deconsolidate the Cartagena balance sheet and statement of operations and to reflect AES share of the results of it s operations using the equity method of accounting. This resulted in a decrease to investments in affiliates of $55 and $39 million; a decrease in net property, plant and equipment of $570 and $387 million; and a decrease in non-recource debt of $579 and $497 million at December 31, 2005 and 2004, respectively.

Restricted Cash

Certain balance sheet reclassifications were recorded at December 31, 2005 and December 31, 2004 that were the result of errors in the presentation of restricted cash. These reclassifications resulted in a reduction in cash and cash equivalents and an increase in restricted cash by $63 million and $97 million, in 2005 and 2004, respectively.

Share-based Compensation

The Company recently concluded an internal review of accounting for share-based compensation (the LTC Review), which originally was disclosed in the Company s Form 8-K filed on February 26, 2007. As a result of the LTC Review, the Company identified certain errors in its previous accounting for share-based compensation. These errors required adjustments to the Company s previous accounting for these awards under the guidance of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB No. 25), Financial Accounting Standards Board (FASB) Statement No. 123, *Accounting for Stock-Based Compensation* (FAS No. 123) and FASB Statement No. 123R (revised 2004), *Share-Based Payment* (FAS No. 123R). As described below, the Company is recording adjustments to its prior financial statements resulting in additional cumulative pre-tax compensation expense for the years 2000-2005 of $36 million ($26 million net of taxes). None of these adjustments, individually or in the aggregate, is quantitatively material to any period presented.

In addition, the Company has identified accounting for share-based compensation as a material weakness and has prepared a remediation plan to strengthen further its granting and accounting practices to avoid similar errors in the future. See Item 9A Disclosure Controls and Procedures of this Form 10-K for further explanation of the material weakness and the Company s remediation plans.

Background of the LTC Review

Beginning in mid-2006 the Company conducted limited assessments of its share-based compensation practices. Based on those assessments, it did not appear likely that the potential accounting adjustments relating to share-based compensation issues identified as of that time would be material to the Company s prior period financial statements. However, information subsequently developed by the Company s Internal Audit group indicated that there had been control deficiencies and inadequate oversight related to historical granting practices and accounting for share-based compensation.

Following consideration of this information, the Company determined that a more comprehensive review of prior period awards was warranted. Accordingly, in early February 2007, the Company requested that an outside consulting firm assist with the collection and processing of data relating to the Company s share-based compensation awards. The outside consulting firm also provided a team of forensic accountants to assist the Company with its: (i) evaluation of relevant SEC and FASB guidance relating to share-based compensation; (ii) implementation of procedures for review of electronic data, including e-mails; and (iii) analysis of the information used to determine measurement dates, strike prices and valuations required to reach the resulting accounting adjustments. The Company also asked an outside law firm to assist the Company with the LTC Review. This law firm had already been assisting the Company in responding to requests for documents and information from the SEC Staff principally relating to the Company s restatements for the years 2002-2005. As disclosed in a Form 8-K filed on March 19, 2007, the Financial Audit Committee of the Company s Board of Directors formed an Ad Hoc Committee of three independent directors to review the Company s procedures, conclusions and recommendations regarding the LTC Review, as described herein.

Purposes and Scope of the LTC Review

The LTC Review was designed and conducted principally to determine whether any adjustments to the Company s prior period financial statements were required as a result of incorrect accounting for share-based compensation, which includes stock options and restricted stock units. A secondary purpose of the LTC Review was to evaluate the Company s historical practices and procedures for making share-based compensation awards, including the conduct of individuals involved in the granting process.

The Company determined that a ten-year review period covering the years 1997-2006 (the Review Period) was appropriate. Supporting documentation was more readily available in more recent years and, in many instances, the Company experienced difficulty locating and/or gathering documentation for the years 1997-1999. Therefore, the Company determined that a review of years preceding 1997 was unlikely to result in information susceptible to meaningful analysis.

A significant accounting issue identified in the LTC Review related to the determination of the measurement date with respect to share-based compensation awards. During the Review Period, the Company had generally used the indicated grant date as the measurement date for accounting purposes, when in many cases the indicated grant date actually preceded the measurement date as correctly defined under Generally Accepted Accounting Principles (GAAP). The U.S. GAAP technical accounting literature in effect during the accounting periods under review defined the measurement date for purposes of determining share-based compensation expense as the date on which the Company finalized an individual s share-based award, to include the number of units awarded at a determinable strike price.

The Company gathered documentation and conducted analysis related to measurement dates with respect to all of the grants awarded in the Review Period, a total of approximately 29,600 stock option grants, representing approximately 45,380,000 options as well as approximately 4,000,000 restricted stock units for non-directors. These grants included both the Company s annual compensation awards, known as on-cycle grants, and all awards made at other times, referred to as off-cycle grants. The LTC Review was designed to assess the appropriate measurement date for each of the various types of grants awarded during the Review Period. The Company considered SEC guidance and GAAP in evaluating known facts and circumstances in an attempt reasonably to determine the date that the share-based compensation awards were final. The Company collected information through targeted searches of various sources, including human resources and accounting databases, paper and electronic files and servers, Board of Directors and Compensation Committee meeting minutes, payroll records, and acquisition and business development documentation. The Company also interviewed certain current and former employees, officers and directors.

Although there generally was less documentation readily available for the years 1997-1999, the Company did review grants in those years, and based on available information, attempted to make a reasonable assessment of the correct measurement dates and potential accounting adjustments for the purposes of assessing whether any charge from that period could be material to the Company s financial statements in those years. Based on this analysis, the Company determined that any errors identified during that period would not have resulted in a material impact to the Company s stockholders equity and no adjustments were made.

The Company s Accounting Adjustments

As a result of the LTC Review, the Company has determined that adjustments resulting in charges for share-based compensation should be recorded for the years 2000 through 2005. The additional cumulative pre-tax compensation expense totals $36 million ($26 million net of taxes). The effect of recognizing additional non-cash, share-based compensation expense resulting from the charges mentioned above by year is as follows:

Fiscal Year Ended (in millions)	Pre-Tax Expense	After-Tax Expense
2000	$ 8	$ 6
2001	$ 15	$ 11
2002	$ 8	$ 5
2003	$ 4	$ 3
2004	$	$
2005	$ 1	$ 1

The Company also is recording a charge of $1 million (pre-tax) relating to the first three previously reported quarters of 2006, which primarily relate to prior year grants in which expense was carried forward to 2006.

None of these adjustments, individually or in the aggregate, is quantitatively material to any period presented; however, the Company will reflect these adjustments by reducing stockholders equity by $25 million as of January 1, 2004 for the cumulative effect of the correction of errors for the periods from January 1, 2000 through December 31, 2003. General and administrative expense will be adjusted for the years ending December 31, 2004 and 2005 and the first three quarters of 2006 as outlined above.

Annual On-Cycle Awards. Compensation charges for annual on-cycle grants were determined based upon facts and circumstances relating to the dates the awards were final and the selection of the appropriate strike prices. The Company determined new measurement dates based on a determination of the date an award was final using the following methodology. Grants to Executive Officers and certain other senior executives (Senior Leaders) were considered to be final for accounting purposes upon Compensation Committee approval of a fixed number of options at a specific exercise price, or in certain years based on subsequent action by the Company establishing the grant date and strike price. Grants to all other employees were considered to be final for accounting purposes on the date that management completed its allocation of substantially all awards to the pool of employees receiving awards. In addition to measurement date changes, the LTC Review identified three years in which the Company had set the strike price for the annual on-cycle grants either as the opening price or as the intra-day low trading price of the Company s stock during a four-day period over which a Board meeting was held. To determine the fair market value of the stock on the re-determined measurement date for accounting purposes, the Company used the closing price of the stock on that date. Accordingly, for financial accounting purposes, the amount of compensation expense recorded by the Company reflects both measurement date changes and intrinsic value changes for annual on-cycle awards. The predominant causes of the charges relating to on-cycle grants were (i) with respect to Executive Officers and Senior Leaders, use of a grant date associated with an annual Board meeting, where the grant date and strike price had not been determined with finality until several days after the meeting; and (ii) with respect to all other employees, the failure to finalize a complete and accurate schedule of the awards to be made to the employees contemporaneously with the intended grant date.

Off-Cycle Grants. Compensation charges for off-cycle grants also were based primarily upon the dates the awards were final. The majority of the measurement date changes with respect to off-cycle grants related to the following five categories: (1) awards to newly hired employees; (2) awards upon promotions of existing employees or other change in status; (3) awards made in conjunction with transactions or other successful business development efforts; (4) Founders and other similar awards made in recognition of outstanding service, and (5) corrections to previous awards subsequently determined to have been erroneous.

The predominant cause of the measurement date errors in each of these categories of awards was the lack of adequate contemporaneous documentation supporting the intended grant. Accordingly, the amount of compensation expense recorded by the Company for these categories of off-cycle awards is based primarily upon measurement date changes. The adjustments reflect available evidence concerning the dates on which: (i) the recipients were entitled to receive the awards, (ii) the grants were intended to be made, and (iii) the terms of the grants were final.

In addition to the categories above, off-cycle grants also were defined to include modifications of prior grants. Compensation charges for grant modifications were based upon an analysis of changes to vesting and exercise periods. As a result of its review, the Company has determined that certain modifications were calculated using an incorrect method and others were not communicated to appropriate accounting personnel. The most significant modification relates to a grant to a former CEO that was erroneously accounted for by using an intrinsic value calculation instead of a fair value calculation following the Company s decision to adopt FAS 123 effective January 1, 2003. The Company is recording a $3.1 million charge to account for this error for the year 2003.

Summary of Significant Charges By Grant Year

Set forth in this section is a summary of the charges resulting from grants awarded in the years 2000, 2001 and 2003, which make up more than 95% of the additional expenses requiring adjustments to the prior period financial statements. This information is different than the discussion and table above, which described the effect of recognizing these additional charges over the applicable accounting periods in the Company s financial statements. For these years, further information concerning the type of grant (on-cycle or off-cycle), the categories of the recipients and the nature of the change resulting in the adjustment is set out below.

For grants made in 2000, the total charge resulting from the LTC Review is approximately $22.9 million. Of that amount, approximately $3.8 million resulted from the changes to the on-cycle grants to Executive Officers and Senior Leaders. Of the remaining amount, approximately $17.2 million resulted from the changes to the on-cycle grants to all other employees, and approximately $1.9 million resulted from off-cycle grants.

For grants made in 2001, the total charge resulting from the LTC Review is approximately $8.7 million. Of that amount, approximately $7.2 million resulted from the changes to on-cycle grants to Executive Officers and Senior Leaders. Of the remaining amount, approximately $250,000 resulted from the changes to the on-cycle grants to all other employees, and approximately $1.2 million resulted from off-cycle grants.

For grants made in 2003, the total charge is approximately $6.3 million. Of this amount, $3.1 million related to the modification to a grant to a former CEO as described above, and approximately $800,000 related to a grant to a director approved by shareholders where the grant date was recorded as having been finalized on the date of an earlier Board meeting. The remaining charges resulted from changes to certain on-cycle and off-cycle grants.

The Company s Review of Historic Practices

As noted, the primary purpose of the LTC Review was to conduct a comprehensive review of the Company s accounting for share-based compensation and to record any required adjustments in its financial statements. The LTC Review was not an independent investigation relating to historic practices and procedures. However, during the course of the LTC Review, the Company identified certain historical practices raising issues relating to share-based compensation and conducted a review of those practices, limited in scope as noted herein. Based on the information to date, the Company has identified certain historical issues and practices of concern relating to the annual on-cycle and off-cycle grants, which fall within the following five categories: (1) with respect to the 1997-1998 annual on-cycle grants, reported ratification of undocumented prior on-cycle grants by the Compensation Committee; (2) with respect to the 1999-2001 annual grants, after-the-fact selection of low strike prices within the four-day period during which Board meetings were held, and inaccurate Compensation Committee meeting minutes relating to grant date and strike price selection; (3) issuance of off-cycle grants prior to 2004 based on apparent, but not actual, delegation of authority, as well as general deficiencies in administration of off-cycle grants; (4) failure to establish and/or comply with certain formal corporate governance procedures in periods through 2004; and (5) lack of and/or insufficient controls and procedures, and/or lack of knowledge of applicable accounting standards, in connection with administration of share-based compensation. The Company notes that the senior officers who were primarily involved in the selection of the prices of the annual on-cycle grants from 1999-2001 were the Company s President and CEO at the time, who retired in 2002; the Company s CFO at the time, who left full time employment with the Company in early 2006 (he remains under an employment agreement through March 2008, although he is not active in management); and the Company s General Counsel at the time, who presently is the Company s Executive Vice President and President, Alternative Energy and is no longer involved in the Company s legal functions or Board consideration or approval of share-based compensation.

The information developed in the LTC Review did not establish that any officer or director of the Company manipulated the selection of grant dates or strike prices with actual knowledge that they were violating or causing the Company to violate accounting principles or requirements of the Company s stock options plans, or that there was any effort to conceal information relating to the selection of grant dates or strike prices from the Company s outside auditors. However, all of the matters described herein with respect to the Company s general views and issues arising from the LTC Review are qualified by the fact that, in light of the limitations discussed herein, there may be additional documents, witnesses or other information not reviewed that might have indicated a different result

The limitations of the LTC Review include the fact that the Company did not review backups of data from the First Class System (First Class), the Company s e-mail system prior to January 1, 2002, when the Company switched to Microsoft Outlook. The Company also did not attempt to restore approximately 460 computer tapes (the Backup Tapes) that are stored by an off-site storage vendor. The Company believes that these tapes comprise backups of certain Company electronic data (including e-mail) backed up on certain dates from approximately late 2001 through early 2004, but the Company has not located an index identifying the contents of the tapes.

The Company decided not to attempt to restore and review First Class or the Backup Tapes because: (i) the Company was able to review certain electronic data, including for the years 1997-2002, as well as paper files and other available information relating to the majority of the grants made during the Review Period; (ii) the Company believes that it is unlikely that information from these sources would materially alter the accounting adjustments that have been determined to be necessary; (iii) the Company has implemented or will implement measures necessary to provide effective controls and procedures in these areas; (iv) of the senior officers who were primarily involved in the selection of the prices of the annual on-cycle grants from 1999-2001, the former CEO is no longer with the Company, the former CFO is no longer an officer and is not active in the Company s management, and the former General Counsel has a different position in the Company that does not involve corporate legal responsibilities or participation in Board consideration or approval of share-based compensation; and (v) based on consultation with a reputable information technology vendor, the Company determined that neither First Class nor the Backup Tapes could be restored for review without causing substantial delays in the LTC Review. In addition, while the Company conducted more than twenty interviews with persons who, by virtue of their position or otherwise, were believed to be most likely to have relevant knowledge, the Company did not interview every director or employee who may have had any involvement with options grants or accounting for share-based compensation.

ITEM 1. BUSINESS

Overview

We are a global power holding company incorporated in Delaware in 1981. Through our subsidiaries, we operate a portfolio of electricity generation and distribution businesses and investments on five continents and in 27 countries.

Our Businesses

We operate two types of businesses. The first is our distribution business, which we refer to as Utilities, in which we operate electric utilities and sell power to customers in the retail (including residential), commercial, industrial and governmental sectors. These customers are typically end users of electricity. The second is our Generation business, where we sell power to wholesale customers such as utilities or other intermediaries. In addition to our traditional generation and distribution operations, we are also developing an alternative energy business. The revenues and earnings growth of both our Utilities and Generation businesses vary with changes in electricity demand.

Our Utilities business consists primarily of 13 distribution companies in seven countries with over 10 million end-use customers. All of these companies operate in a defined service area. This segment is comprised of:

- integrated utilities located in:
- the United States Indianapolis Power & Light (IPL);
- Cameroon AES SONEL; and
- distribution companies located in:
- Brazil AES Eletropaulo and AES Sul,
- Argentina Empresa Distribuidora La Plata S.A. (EDELAP), Empresa Distribuidora de Energia Norte (EDEN) and Empresa Distribuidora de Energia Sure (EDES),
- El Salvador Compañia de Alumbrado Eléctrico de San Salvador, S.A. de C.V. (CAESS), Compania, S. En C. de C.V. (AES CLESA), Distribuidora Electrica de Usulutan, S.A. de C.V. (DEUSEM) and Empresa Electrica de Oriente (EEO) and
- Ukraine Kievoblenergo and Rivneenergo.

Performance drivers for these businesses include, among other things, reliability of service, management of working capital, negotiation of tariff adjustments, compliance with extensive regulatory requirements and, in developing countries, reduction of commercial and technical losses.

Utilities face relatively little direct competition due to significant barriers to entry which are present in these markets. In this segment, we primarily face competition in our efforts to acquire businesses. We compete against a number of other participants, some of which have greater financial resources, have been engaged in distribution related businesses for periods longer than we have, and have accumulated more significant portfolios. Relevant competitive factors for Utilities include financial resources, governmental assistance, regulatory restrictions and access to non-recourse financing. In certain locations our utilities face increased competition as a result of changes in laws and regulations which allow wholesale and retail services to be provided on a competitive basis. We can provide no assurance that deregulation will not adversely affect the future operations, cash flows and financial condition of our Utilities business. The results of operations of our Utilities business are sensitive to changes in economic growth and regulation, abnormal weather conditions in the area in which they operate, as well as the success of the operational changes that have been implemented (especially in emerging markets).

In our Generation business we generate and sell electricity primarily to wholesale customers. Performance drivers for our Generation business include, among other things, plant reliability, fuel costs and fixed-cost management. Growth in this business is largely tied to securing new power purchase agreements, expanding capacity in our existing facilities and building new power plants. Our Generation business includes our interests in 94 power generation plants totaling over 35 gigawatts of capacity installed in 21 countries.

Approximately 68% of the revenues from our Generation business are from plants that operate under power purchase agreements of five years or longer for 75% or more of the output capacity. These long-term contracts reduce the risk associated with volatility in the market price for electricity. We also reduce our exposure to fuel supply risks by entering into long-term fuel supply contracts or through fuel tolling contracts where the customer assumes full responsibility for purchasing and supplying the fuel to the power plant. As a result of these contractual agreements, these facilities have relatively predictable cash flows and earnings. These facilities face most of their competition prior to the execution of a power sales agreement, during the development phase of a project. Our competitors for these contracts include other independent power producers and equipment manufacturers, as well as various utilities and their affiliates. During the operational phase, we traditionally have faced limited competition due to the long-term nature of the generation contracts. However, since competitive power markets have been introduced and new market participants have been added, we have and will continue to encounter increased competition in attracting new customers and maintaining our current customers as our existing contracts expire.

The balance of our Generation business sells power through competitive markets under short-term contracts or directly in the spot market. As a result the cash flows and earnings associated with these facilities are more sensitive to fluctuations in the market price for electricity, natural gas, coal and other fuels. However, for a number of these facilities, including our plants in New York which include a fleet of low-cost coal fired plants, we have hedged the majority of our exposure to fuel, energy and emissions pricing for the next several years. These facilities compete with numerous other independent power producers, energy marketers and traders, energy merchants, transmission and distribution providers and retail energy suppliers. Competitive factors for these facilities include price, reliability, operational cost and third party credit requirements.

Recent Initiatives

We are always seeking opportunities to grow our businesses and increase the value of our stock, both within our existing Generation and Utilities businesses and in new lines of businesses. When exploring new businesses, we seek opportunities that leverage the skills and experience we have developed in our core business. These core competencies include: financing, constructing and developing large, capital-intensive projects; negotiating and closing complex merger, acquisition, disposition and investment transactions; operating businesses that are heavily-regulated; and conducting business and establishing operations around the world, including in countries where relationships and insight into local rules, regulations, politics and business practices provide us with a competitive advantage.

In our existing businesses we are currently seeing increased demand for power plants sited adjacent to coal resources in markets such as Vietnam, India and Indonesia. Some of the important drivers of performance for us in developing our alternative energy businesses include continued government support through regulation and incentives, continued progress towards liquid and transparent markets, particularly in the area of greenhouse gas emission credit trading, and the successful identification, execution and commercialization of new market opportunities in these nascent markets.

We are also developing an alternative energy business including wind generation, the supply of liquefied natural gas (LNG), greenhouse gas emission reduction projects and new energy technologies. In Qatar and Oman we own and operate water desalination plants, and in the Dominican Republic we own and operate a LNG re-gasification terminal, which are ancillary to our existing power businesses.

Our Organization

Our business operations are organized along geographic lines, with regional management teams responsible for the financial results in their respective territories. Each of the four regions, (1) North America, (2) Latin America, (3) Europe, CIS & Africa, which we refer to as Europe & Africa and (4) Asia and the Middle East, which we refer to as Asia , are led by a Regional President reporting to our Chief Operating Officer (COO) who reports to the Chief Executive Officer (CEO). Our Alternative Energy business is led by an Executive Vice President, who reports to the CEO. Supporting these businesses is a business excellence group providing expertise in areas such as procurement, engineering and construction, safety, environment, information technology and performance improvement. This group is also led by an Executive Vice President who reports to the COO.

We believe that our organizational structure, including our use of regional management teams, is the most effective method to manage our business. We target geographic regions as primary areas of expansion because our regional management structure provides us with important relationships in key markets and helps us identify localities with a large and growing need for power and other favorable characteristics for new investment. Regional management also allows for a hands-on approach to operations and business developments, which helps us assess and manage the risks associated with our new investments in each region. As a large organization we believe we have the resources and the ability to capitalize on economies of scale and develop better operating and management practices to increase our overall efficiency and productivity. Finally, our broad geographic footprint reduces political, macroeconomic and other risks associated with conducting business in any particular region.

Subsequent Events

On February 22, 2007, we entered into a definitive agreement with Petróleos de Venezuela, S.A., (PDVSA), pursuant to which we have agreed to sell to PDVSA all of our shares of EDC. The agreement is dated as of February 15, 2007. Subject to the terms and conditions in the agreement, PDVSA agreed to pay us a purchase price of US$739 million at closing, net of any withholding taxes. In addition, the agreement provided for the payment of a US$120 million dividend in 2007. On March 1, 2007, the shareholders of EDC approved and declared a US$120 million dividend, payable on March 16, 2007, to all shareholders on record as of March 9, 2007. A wholly-owned subsidiary of the Company is the owner of 82.14% of the outstanding shares of EDC, and therefore, on March 16, 2007, this subsidiary received the equivalent of approximately US$99 million in Bolivares that is currently being held in trust at a U.S. bank until the funds can be converted to U.S. Dollars. Under the terms of the purchase and sale agreement with the Republic of Venezuela, PDVSA has agreed to ensure that the Company s portion of the dividend is converted by the Venezuelan government s Foreign Exchange Commission, CADIVI, from Bolivares into U.S. Dollars at the current official exchange rate within 90 days of the dividend payment date. As of the date of this filing, the conversion of the Company s portion of the dividend from Bolivares to U.S. Dollars has been submitted to CADIVI and is awaiting their approval.

The agreement provided that PDVSA would acquire our EDC common shares in a tender offer. PDVSA commenced and publicly announced the commencement of concurrent tender offers in Venezuela and the United States (the Offers), on April 9, 2007. The Offers provided for the purchase of 2,704,445,687 of EDC common shares at a U.S. Dollar equivalent amount of $0.2734 per common share, which is consistent with the price per share implied by the purchase price within the agreement. The closing of the Offers occurred on May 8, 2007, the actual transfer of the shares along with payment of the purchase price occurred on May 16, 2007.

As a result of signing this agreement, we have concluded that a material impairment of our investment in EDC has occurred, which will be recorded in the first quarter ending March 31, 2007. This material impairment represents the net book value of our investment less the estimated purchase price. Management estimates that this pre-tax, non-cash charge will be in the range of $600 to $650 million.

We purchased a controlling interest in EDC in 2000. EDC is the largest private electric utility in Venezuela. It is a provider of power and light to approximately one million customers in the Caracas metropolitan area. EDC also owns and operates five generation plants with a total of 2,616 MW of generation capacity. These facilities collectively represent approximately 14% of the electricity consumed in Venezuela.

For the year ended December 31, 2006, EDC represented 5% of AES consolidated revenues and 12% of the Latin America Utilities segment revenues, 5% of AES consolidated gross margin and 17% of the Latin America Utilities segment gross margin. In addition, EDC represented 37% of AES consolidated net income and 36% of basic earnings per share. Excluding the net after-tax loss impact of $512 million related to the sale of Eletropaulo shares and debt restructuring, EDC represented 12% of AES consolidated net income and 12% of basic earnings per share. AES received a dividend of approximately $101 million from EDC in 2006. EDC s five generation plants represented approximately 7% of AES approximate 35 gigawatts of capacity installed.

Segments

Beginning with this Annual Report on Form 10-K, AES realigned its reportable segments We previously reported under three segments: Regulated Utilities, Contract Generation and Competitive Supply. The Company currently reports seven segments as of December 31, 2006, which include:

- Latin America Generation;
- Latin America Utilities;
- North America Generation;
- North America Utilities;
- Europe & Africa Generation;
- Europe & Africa Utilities;
- Asia Generation

The additional segment reporting better reflects how AES manages the company internally in terms of decision making and assessing performance. The Company manages its business primarily on a geographic basis in two distinct lines of business the generation of electricity and the distribution of electricity. These businesses are distinguished by the nature of the customers, operational differences, cost structure, regulatory environment and risk exposure.

Latin America

Our Latin American operations accounted for 58%, 58% and 54% of consolidated revenues in 2006, 2005, and 2004, respectively. AES began operating in Latin America in 1993 when it acquired the CTSN power plant in Argentina. Since that time, AES has expanded its presence in the region and now has operations in eight Latin American countries. These operations include a total of 48 generation plants owned and operated under management agreements with a total generating capacity of 11,217 MW. AES owns and operates 9 utilities, distributing a total of 48,058 GWh, in addition to operating one utility under management agreement, which distributes 1,626 GWh to customers.

Latin American Generation. Our Generation business in Latin America consists of 47 generation facilities with the capacity to generate 11,217 MW. This capacity includes our new 125 MW Los Vientos diesel-fired peaking facility, which came on line in January, 2007 and serves the largest power market in Chile. AES also has two coal plants under construction in Chile, Guacolda III and Ventanas III with 152 MW and 267 MW generation capacity respectively, and one plant under construction in Panama, the Changuinola hydro plant with 223 MW capacity.

Latin American Utilities. We own 9 Utility businesses, including electricity distribution businesses located in Argentina (EDELAP, EDEN and EDES), Brazil (AES Eletropaulo and AES Sul) and El Salvador (CAESS, CLESA, DEUSEM and EEO). Our tenth Utility business, EDC, was sold in May 2007. We also manage another utility under contract in the Dominican Republic. These businesses sell electricity under regulated tariff agreements and each has transmission and distribution capabilities. AES Eletropaulo, serving the São Paulo, Brazil area for over 100 years, has over five million customers and is the largest electricity distribution company in Brazil in terms of revenues and electricity distributed. Pursuant to its concession contract, AES Eletropaulo is entitled to distribute electricity in its service area until 2028. AES Eletropaulo s service territory consists of 24 municipalities in the greater São Paulo

metropolitan area and adjacent regions that account for approximately 15% of Brazil s GDP and 44% of the population in the State of São Paulo, Brazil.

North America

Our North American operations accounted for 23%, 25% and 27% of consolidated revenues in 2006, 2005 and 2004, respectively. AES began operating in North America in 1985, when it developed its first power plant in Deepwater, Texas. Since then AES has grown its North America business and currently owns a total of 27 generation facilities with 13,576 MW generating capacity and one integrated utility, distributing approximately 16,287 GWh of electricity to customers.

North American Generation. In North America, AES has 23 generation facilities, including seven gas-fired plants, ten coal-fired plants, three petroleum coke-fired plants and three biomass-fired plants, in the United States, Puerto Rico and Mexico.

North American Utilities. AES has one integrated utility in North America, Indianapolis Power & Light Company (IPL), which it owns through IPALCO Enterprises Inc. (IPALCO), the parent holding company of IPL. IPL is engaged in generating, transmitting, distributing and selling electric energy to more than 465,000 customers in the city of Indianapolis and neighboring areas within the state of Indiana. IPL also owns and operates four generation facilities. Two generating facilities are primarily coal-fired plants. The third facility has a combination of units that use coal (base load capacity) and natural gas and/or oil (peaking capacity). The fourth facility is a small peaking station that uses gas-fired combustion turbine technology. IPL s gross generation capability is 3,599 MW.

Europe & Africa

Our operations in Europe & Africa accounted for 12%, 12% and 12% of our consolidated revenues in 2006, 2005 and 2004, respectively. AES began operations in Europe & Africa in 1992, when we acquired the AES Kilroot power plant in Northern Ireland. Since that time, AES has grown in this region and now has a presence in nine countries. AES s operations in the region now include a total of 24 generation plants owned or operated under management agreements with a total of 11,431 MW generation capacity. AES owns and operates three utilities, distributing a total of 8,960 GWh, in addition to operating 2 utilities under management agreement in the region, which distribute a total of 2,096 GWh.

Europe & Africa Generation. We own 11 generation facilities in Europe & Africa, and operate two additional generation facilities under management contract in Kazakhstan. These generation facilities have the capacity to generate 10,504 MW. In 2006, we began commercial operation of AES Cartagena, our first power plant in Spain with 1,200 MW capacity. AES Maritza East 1 is a 670 MW lignite-fired power plant currently under construction in Bulgaria.

Europe & Africa Utilities. We own three Utility businesses in Europe & Africa, including an integrated utility in Cameroon (AES SONEL) and two distribution businesses in Ukraine (Kievoblenergo and Rivneenergo). AES acquired a 56% interest in AES SONEL in 2001. AES SONEL generates, transmits and distributes electricity to approximately 538,000 customers. AES SONEL has an installed generating capacity of 927 MW, and a small plant under construction. Our two distribution businesses in Ukraine serve over 1.2 million customers, while the two distribution businesses we operate under management agreements in Kazakhstan together serve over 554,000 customers.

Asia

Our Asian operations accounted for 7%, 6% and 6% of consolidated revenues in 2006, 2005 and 2004, respectively. AES began operations in Asia in 1994 when we acquired the Cili power plant in China. Since that time AES s Generation business has expanded and it now operates 13 power plants with a total capacity of 5,369 MW in six countries. AES only operates generation facilities in Asia.

Asia Generation. AES has 13 generation facilities with the capacity to generate 5,369 MW. Over half of our facilities and capacity are located in China, where AES joined with Chinese partners to build Yangcheng, the first coal-by-wire power plant with the capacity of 2100 MW. In 2000, AES was selected by the Sultanate of Oman to build, own and operate a 456 MW and 20 MIGD combined power and desalinated water facility, which achieved commercial operations in 2003. In 2001, AES was awarded the right to build, own and operate for 25 years a 756 MW and 40 MIGD combined power and desalinated water facility, the first such facility to be awarded to the private sector in Qatar. This facility commenced commercial operations in 2004. AES also owns and operates two oil-fired facilities in Pakistan (Lal Pir and Pak Gen), which have been in operations for the last nine years. In India, AES acquired a 420 MW coal-fired power plant (OPGC) in 1998. In Sri Lanka, AES owns a 168 MW diesel-fired power plant that began commercial operations in 2003. AES Amman East is a 370 MW combined-cycle gas power plant under construction in Jordan.

Corporate and Other

Corporate and other expenses include general and administrative expenses related to corporate staff functions and initiatives primarily executive management, finance, legal, human resources, information systems and certain development costs which are not allocable to our business segments; interest income and interest expense; and intercompany charges such as management fees and self insurance premiums which are fully eliminated in consolidation.

In addition, Corporate and Other also includes net operating results of our Alternative Energy business which is not material to our presentation of operating segments. We own and operate 298 MW of wind generation capacity and operate an additional 298 MW capacity through operating and management or O&M agreements. We also have ownership interests in development-stage companies in Scotland, France and Bulgaria. In 2006, we began construction of the 233 MW Buffalo Gap 2 wind farm in Texas.

The table below presents information about our consolidated operations and long-lived assets, by country, for years ended December 31, 2006 through December 31, 2004 and as of December 31, 2006 and 2005, respectively. Revenues are recorded in the country in which they are earned and assets are recorded in the country in which they are located.

	Revenues			**Property, Plant & Equipment, net**	
	2006	**2005**	**2004**	**2006**	**2005**
	(in millions)				
United States	$ 2,544	$ 2,335	$ 2,213	$ 5,890	$ 5,609
Non-U.S.					
Brazil	4,161	3,823	2,925	4,567	4,130
Argentina	542	438	320	412	418
Chile	595	542	436	812	796
Venezuela	652	635	619	1,859	1,861
Dominican Republic	357	231	168	653	476
El Salvador	437	377	356	241	225
Pakistan	373	219	210	272	288
United Kingdom	222	208	215	303	282
Cameroon	302	288	272	407	354
Mexico	185	226	186	188	195
Puerto Rico	234	213	188	626	643
Hungary	304	230	192	225	209
Ukraine	269	217	190	106	97
Qatar	169	165	129	578	603
Colombia	184	182	132	398	407
Panama	144	134	117	450	454
Oman	114	113	110	337	346
Kazakhstan	215	158	137	175	150
Other Non-U.S.	296	287	277	575	490
Total Non-U.S.	$ 9,755	$ 8,686	$ 7,179	$ 13,184	$ 12,424
Total	$ 12,299	$ 11,021	$ 9,392	$ 19,074	$ 18,033

Facilities

The following tables present information with respect to the facilities in each of our business segments as of December 31, 2006. The amounts under Gross Megawatt (MW) and Approximate Gigawatt Hours represent the gross amounts for each facility without regard to our percentage of ownership interest in the facility.

Segment Latin America Generation

Business	Location	Fuel	Gross M W	AES Equity Interest (Rounded)	Year Acquired or Began Operation
Alicura	Argentina	Hydro	1,050	99%	2000
Central Dique	Argentina	Gas / Diesel	68	51%	1998
Gener - TermoAndes	Argentina	Gas	643	91%	2000
Paraná-GT	Argentina	Gas	845	100%	2001
Quebrada de Ullum(1)	Argentina	Hydro	45		2004
Rio Juramento - Cabra Corral	Argentina	Hydro	102	98%	1995
Rio Juramento - El Tunal	Argentina	Hydro	10	98%	1995
San Juan - Sarmiento	Argentina	Gas	33	98%	1996
San Juan - Ullum	Argentina	Hydro	45	98%	1996
San Nicolás	Argentina	Coal / Gas / Oil	675	99%	1993
Tietê(2)	Brazil	Hydro	2,650	24%	1999
Uruguaiana	Brazil	Gas	639	46%	2000
Gener - Electrica de Santiago(3)	Chile	Gas / Oil	479	82%	2000
Gener - Energía Verde(4)	Chile	Biomass / Diesel	42	91%	2000
Gener - Gener(5)	Chile	Hydro / Coal / Oil	807	91%	2000
Gener - Guacolda	Chile	Coal	304	46%	2000
Gener - Norgener	Chile	Coal / Pet Coke	277	91%	2000
Chivor	Colombia	Hydro	1,000	91%	2000
Andres	Dominican Republic	Gas	319	100%	2003
Itabo(6)	Dominican Republic	Coal / Oil	472	48%	2000
Los Mina	Dominican Republic	Gas	236	100%	1997
Bayano	Panama	Hydro	260	49%	1999
Chiriqui - Esti	Panama	Hydro	120	49%	2003
Chirqui - La Estrella	Panama	Hydro	45	49%	1999
Chirqui - Los Valles	Panama	Hydro	51	49%	1999
			11,217		

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

(2) Tietê plants: Água Vermelha, Bariri, Barra Bonita, Caconde, Euclides da Cunha, Ibitinga, Limoeiro, Mog-Guaçu, Nova Avanhandava and Promissão

(3) Gener - Electrica de Santiago plants: Nueva Renca and Renca

(4) Gener - Energia Verde Plants: Constitución, Laja and San Francisco de Mostazal

(5) Gener - Gener plants: Ventanas, Laguna Verde, Laguna Verde Turbogas, Alfalfal, Maitenas, Queltehues, Volcán and Los Vientos. Los Vientos started full commercial operations in January, 2007

(6) Itabo plants: Itabo, Santo Domingo, Timbegue, Los Mina and Higuamo

Generation under construction

Business	Location	Fuel	Gross M W	AES Equity Interest (Rounded)	Expected Year of Commercial Operation
Guacolda III	Chile	Coal	152	46%	2009
Ventanas III	Chile	Coal	267	91%	2010
Changuinola	Panama	Hydro	223	83%	2010
			642		

Segment Latin America Utilities

Business	Location	Fuel	Gross MW	AES Equity Interest (Rounded)	Year Acquired or Began Operation
EDC(1)(2)	Venezuela	Oil/Gas	2,616	82 %	2000

(1) EDC plants: Amplicacion Tacoa, Tacoa, Arrecifes, Oscar Augusto Machado and Genevapca

(2) AES sold its interest in EDC to the PDVSA in May 2007

Distribution

Business	Location	Approximate Number of Customers Served as of 12/31/2006	Approximate Gigawatt Hours Sold in 2006	AES Equity Interest (Rounded)	Year Acquired
Edelap	Argentina	302,845	2,450	90%	1998
Eden	Argentina	306,885	2,273	90%	1997
Edes	Argentina	156,908	751	90%	1997
Eletropaulo	Brazil	5,468,727	31,656	16%	1998
Sul	Brazil	1,071,860	7,545	100%	1997
CAESS	El Salvador	491,631	2,091	75%	2000
CLESA	El Salvador	281,473	764	64%	1998
DEUSEM	El Salvador	53,000	95	74%	2000
EEO	El Salvador	207,441	433	89%	2000
EDC(1)	Venezuela	1,103,149	10,523	82%	2000
		9,443,919	58,581		

(1) AES sold its interest in EDC to the PDVSA in May 2007

Distribution businesses under AES management

Business	Location	Approximate Number of Customers Served as of 12/31/2006	Approximate Gigawatt Hours Sold in 2006	AES Equity Interest (Rounded)
EDE Este(1)	Dominican Republic	330,187	1,626	

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

Segment North America Generation

Business(1)	Location	Fuel	Gross M W	AES Equity Interest (Rounded)	Year Acquired or Began Operation
Mérida III	Mexico	Gas	484	55%	2000
Termoelectrica del Golfo (TEG)(2)	Mexico	Pet Coke	230	100%	2007
Termoelectrica del Peñoles (TEP)(2)	Mexico	Pet Coke	230	100%	2007
Central Valley - Delano	USA - CA	Biomass	57	100%	2001
Central Valley - Mendota	USA - CA	Biomass	28	100%	2001
Placerita	USA - CA	Gas	120	100%	1989
Southland - Alamitos	USA - CA	Gas	2,047	100%	1998
Southland - Huntington Beach	USA - CA	Gas	904	100%	1998
Southland - Redondo Beach	USA - CA	Gas	1,376	100%	1998
Thames	USA - CT	Coal	208	100%	1990
Hawaii	USA - HI	Coal	203	100%	1992
Warrior Run	USA - MD	Coal	205	100%	2000
Hemphill	USA - NH	Biomass	16	67%	2001
Red Oak	USA - NJ	Gas	832	100%	2002
Cayuga	USA - NY	Coal	306	100%	1999
Greenidge	USA - NY	Coal	161	100%	1999
Somerset	USA - NY	Coal	675	100%	1999
Westover	USA - NY	Coal	126	100%	1999
Shady Point	USA - OK	Coal	320	100%	1991
Beaver Valley	USA - PA	Coal	125	100%	1985
Ironwood	USA - PA	Gas	710	100%	2001
Puerto Rico	USA - PR	Coal	454	100%	2002
Deepwater	USA - TX	Pet Coke	160	100%	1986
			9,977		

(1) AES additionally owns and operates the Coal Creek Minerals coal mine in Oklahoma, USA

(2) Acquired February, 2007

Segment North America Utilities

Business	Location	Fuel	Gross M W	AES Equity Interest (Rounded)	Year Acquired or Began Operation
IPL(1)	USA - IN	Coal/Gas/Oil	3,599	100%	2001

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

Distribution

Business	Location	Approximate Number of Customers Served as of 12/31/2006	Approximate Gigawatt Hours Sold in 2006	AES Equity Interest (Rounded)	Year Acquired
IPL	USA - IN	468,867	16,287	100%	2001

Segment Europe & Africa Generation

Business(1)	Location	Fuel	Gross M W	AES Equity Interest (Rounded)	Year Acquired or Began Operation
Bohemia	Czech Republic	Coal/Biomass	50	100%	2001
Borsod	Hungary	Biomass/Coal	96	100%	1996
Tisza II	Hungary	Gas/Oil	900	100%	1996
Tiszapalkonya	Hungary	Biomass/Coal	116	100%	1996
Ekibastuz	Kazakhstan	Coal	4,000	100%	1996
Shulbinsk HPP(2)	Kazakhstan	Hydro	702		1997
Sogrinsk CHP	Kazakhstan	Coal	301	100%	1997
Ust - Kamenogorsk HPP(2)	Kazakhstan	Hydro	331		1997
Ust - Kamenogorsk CHP	Kazakhstan	Coal	1,354	100%	1997
Elsta	Netherlands	Gas	630	50%	1998
Ebute	Nigeria	Gas	304	95%	2001
Cartagena	Spain	Gas	1,200	71%	2006
Kilroot	United Kingdom	Coal/Oil	520	97%	1992
			10,504		

(1) AES additionally owns and operates the Maikuben West coal mine in Kazakhstan, supplying coal to AES businesses and third parties

(2) AES operates these facilities through management or operations and maintenance agreements and owns no equity interest in these businesses

Generation under construction

Business	Location	Fuel	Gross M W	AES Equity Interest (Rounded)	Expected Year of Commercial Operation
Maritza East I	Bulgaria	Lignite	670	100%	2009

Segment Europe & Africa Utilities

Business	Location	Fuel	Gross M W	AES Equity Interest (Rounded)	Year Acquired or Began Operation
SONEL(1)	Cameroon	Hydro/Diesel/Heavy Fuel Oil	927	56 %	2001

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

Generation under construction

Business	Location	Fuel	Gross M W	AES Equity Interest (Rounded)	Expected Year of Commercial Operation
SONEL(1)	Cameroon	Heavy Fuel Oil	13	56 %	2007

Distribution

Business	Location	Approximate Number of Customers Served as of 12/31/2006	Approximate Gigawatt Hours Sold in 2006	AES Equity Interest (Rounded)	Year Acquired
SONEL	Cameroon	538,257	3,374	56 %	2001
Kievoblenergo	Ukraine	833,005	3,639	89 %	2001
Rivneenergo	Ukraine	402,541	1,947	81 %	2001
		1,773,803	8,960		

Distribution businesses under AES management

Business	Location	Approximate Number of Customers Served as of 12/31/2006	Approximate Gigawatt Hours Sold in 2006	AES Equity Interest (Percent, Rounded)
Eastern Kazakhstan REC(1)(2)	Kazakhstan	460,087	2,096	
Ust-Kamenogorsk Heat Nets(1)(3)	Kazakhstan	94,748		
		554,835		

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

(2) Eastern Kazakhstan REC sells power to ShygysEnergo Trade company, an AES subsidiary in Kazakhstan that distributes electricity to customers in Ust-Kamenogorsk and Semipalatinsk areas

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

Segment Asia Generation

Business	Location	Fuel	Gross M W	AES Equity Interest (Rounded)	Year Acquired or Began Operation
Aixi	China	Coal	51	71%	1998
Chengdu	China	Gas	50	35%	1997
Cili	China	Hydro	26	51%	1994
Hefei	China	Oil	115	70%	1997
Jiaozuo	China	Coal	250	70%	1997
Wuhu	China	Coal	250	25%	1996
Yangcheng	China	Coal	2,100	25%	2001
OPGC	India	Coal	420	49%	1998
Barka	Oman	Gas	456	35%	2003
Lal Pir	Pakistan	Oil	362	55%	1997
Pak Gen	Pakistan	Oil	365	55%	1998
Ras Laffan	Qatar	Gas	756	55%	2004
Kelanitissa	Sri Lanka	Diesel	168	90%	2003
			5,369		

Generation under construction

Business	Location	Fuel	Gross M W	AES Equity Interest (Rounded)	Expected Year of Commercial Operation
Amman East(1)	Jordan	Gas	370	60 %	2009

(1) Construction of the Amman East power plant commenced in May, 2007

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Alternative Energy (included in Corporate and Other)

Generation

Business	Location	Fuel	Gross M W	AES Equity Interest (Rounded)	Year Acquired or
Altamont	USA - CA	Wind	43	100%	2005
Palm Springs	USA - CA	Wind	30	100%	2006
Tehachapi	USA - CA	Wind	54	100%	2006
Condon(1)	USA - OR	Wind	50		2005
Buffalo Gap(1)	USA - TX	Wind	121		2006
			298		

(1) AES owns Condon and Buffalo Gap wind facilities together with third party equity investors with variable equity ownership interests. It also has ownership interests in development-stage companies in Scotland, France and Bulgaria.

Alternative Energy businesses under AES management

Business	Location	Fuel	Gross M W	AES Equity Interest (Percent, Rounded)
Wind generation facilities(1)	USA	Wind	298	

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

Alternative Energy businesses under construction

Business	Location	Fuel	Gross M W	AES Equity Interest (Rounded)	Expected Year of Commercial Operation
Buffalo Gap II	USA - TX	Wind	233	100%	2007

Customers

We sell to a wide variety of customers. No individual customer accounted for 10% or more of our 2006 total revenues.

Employees

As of December 31, 2006, we employed approximately 32,000 people.

How to Contact AES and Sources of Other Information

Our principal offices are located at 4300 Wilson Boulevard, Arlington, Virginia 22203. Our telephone number is (703) 522-1315. Our website address is http://www.aes.com. Our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K and any amendments to such reports filed pursuant to section 13(a) or Section 15(d) of the Securities Exchange Act of 1934 are posted on our website. After the reports are filed or furnished with the Securities and Exchange Commission (SEC), they are available from us free of charge. Material contained on our website is not part of and is not incorporated by reference in this Annual Report on Form 10-K.

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

Our Code of Business Conduct and Ethics (Code of Conduct) and Corporate Governance Guidelines have been adopted by our Board of Directors. The Code of Conduct is intended to govern as a requirement of employment the actions of everyone who works at AES, including employees of our subsidiaries and affiliates. The Code of Conduct and the Corporate Governance Guidelines are located in

their entirety on our web site. Any person may obtain a copy of the Code of Conduct or the Corporate Governance Guidelines without charge by making a written request to: Corporate Secretary, The AES Corporation, 4300 Wilson Boulevard, Arlington, VA 22203. If any amendments to or waivers from the Code of Conduct or the Corporate Governance Guidelines are made, we will disclose such amendments or waivers on our website.

Executive Officers of the Registrant

The following individuals are our executive officers:

Paul Hanrahan, 49 years old, has been our President and Chief Executive Officer since 2002. Prior to assuming his current position, Mr. Hanrahan was our Chief Operating Officer and Executive Vice President. In this role, he was responsible for business development activities and the operation of multiple electric utilities and generation facilities in Europe, Asia and Latin America. Mr. Hanrahan was previously the President and CEO of the AES China Generating Company, Ltd., a public company formerly listed on NASDAQ. Mr. Hanrahan also has managed other AES businesses in the United States, Europe and Asia. Prior to joining AES, Mr. Hanrahan served as a line officer on the U.S. fast attack nuclear submarine, USS Parche (SSN-683). Mr. Hanrahan is a graduate of Harvard Business School and the U.S. Naval Academy.

David S. Gee 52 years old, became an Executive Vice President of the Company in 2006 and the Regional President of North America in 2005. Prior to joining us in 2004, Mr. Gee was Vice President of Strategic Planning for PG&E in San Francisco, California from 2000 until 2004. Mr. Gee was a principal consultant for McKinsey & Co. from 1985 to 2000 in Houston, Mexico City and London. He was also an Associate for Baker Hughes and Booz Allen & Hamilton in Houston, Texas. Mr. Gee has a Bachelor of Science degree in Chemical Engineering from the University of Virginia and a Master of Science degree in Finance from the Sloan School of Management at the Massachusetts Institute of Technology.

Andres R. Gluski, 49 years old, has been an Executive Vice President and Chief Operating Officer of the Company since March 2007. Prior to becoming the Chief Operating Officer, Mr. Gluski was Executive Vice President and the Regional President of Latin America since 2005, and will continue as Regional President until a new Regional President is named. Mr. Gluski was Senior Vice President for the Caribbean and Central America from 2003 to 2005, was Group Manager and CEO of Electricidad de Caracas (EDC) (Venezuela) from 2002 to 2003, served as CEO of Gener (Chile) in 2001 and was Executive Vice President of EDC and Corporacion EDC. Prior to joining us in 1997, Mr. Gluski was Executive Vice President of Corporate Banking for Banco de Venezuela and Executive Vice President of Finance of CANTV in Venezuela. Mr. Gluski is a graduate of Wake Forest University and holds a Master of Arts and a Doctorate in Economics from the University of Virginia.

Victoria D. Harker, 42 years old, has been an Executive Vice President and our Chief Financial Officer since January 2006. Prior to joining us, Ms. Harker held the positions of Acting Chief Financial Officer, Senior Vice President and Treasurer of MCI from November 2002 through January 2006. Prior to that, Ms. Harker served as Chief Financial Officer of MCI Group, a unit of WorldCom Inc., from 1998 to 2002. Prior to 1998, Ms. Harker held several positions at MCI in the areas of finance, information technology and operations. Ms. Harker received her Bachelor of Arts degree in English and Economics from the University of Virginia and a Master s in Business Administration, Finance from American University.

Robert F. Hemphill, Jr., 63 years old, has been an Executive Vice President of the Company since rejoining us in February 2004. Mr. Hemphill served as our Director from June 1996 to February 2004 and was an Executive Vice President from 1982 to June 1996. Prior to this, Mr. Hemphill held various leadership positions since joining us in 1982. Mr. Hemphill also serves on the Boards of Reactive Nanotechnologies, Inc., Trophogen Inc. and the Electric Drive Transportation Association. Mr. Hemphill received a Bachelor of Arts degree in Political Science from Yale University, a Master of Arts in Political

Science from the University of California, Los Angeles, and a Master s in Business Administration, Finance from George Washington University.

Jay L. Kloosterboer, 46 years old, is our Executive Vice President of Business Excellence. Mr. Kloosterboer joined us in 2003 as Vice President and Chief Human Resource Officer. Prior to joining us, Mr. Kloosterboer held the positions of Vice President- Human Resources and Communications, Automation and Control Solutions; Vice President Human Resources, Home & Building Control; Vice President- Human Resources, Aerospace Services; Vice President Human Resources & Communications, Automotive Products Group and Director-Human Resources, Automotive Aftermarket of Honeywell International from 1996 to 2003. Mr. Kloosterboer also held management positions at General Electric and Morgan Stanley. He received his Bachelor of Arts degree from Marquette University and holds a Master of Arts degree from the New Mexico State University.

William R. Luraschi, 43 years old, is our Executive Vice President of Business Development and President of the Alternative Energy Business. Mr. Luraschi joined us in 1993 and has been an Executive Vice President since July 2003. He was our General Counsel from January 1994 until May 2005. Mr. Luraschi also served as Corporate Secretary from February 1996 until June 2002. Prior to joining us, he was an attorney with the law firm of Chadbourne & Parke, LLP. Mr. Luraschi received a Bachelor of Science from the University of Connecticut and holds a Juris Doctorate from Rutgers School of Law.

Brian A. Miller, 41 years old, is our Executive Vice President, General Counsel and Corporate Secretary. Mr. Miller joined us in 2001 and has served in various positions including Vice President, Deputy General Counsel, Corporate Secretary, General Counsel for North America and Assistant General Counsel. Prior to joining us, he was an attorney with the law firm Chadbourne & Parke, LLP. Mr. Miller received his bachelor s degree in History and Economics from Boston College and holds a Juris Doctorate from the University of Connecticut School of Law.

***John McLaren,* 44 years old, is an Executive Vice President of the Company, and Regional President of Europe & Africa. Mr. McLaren served as Vice President of Operations for AES Europe & Africa from 2003 to 2006 (and AES Europe, Middle East and Africa from May 2005 to January 2006), Group Manager for Operations in Europe & Africa from 2002 to 2003, Project Director from 2000 to 2002, and Business Manager for AES Medway Operations Ltd. from 1997 to 2000. Mr. McLaren joined us in 1993. He holds a Master s in Business Administration from the University of Greenwich Business School in London.**

***Mark E. Woodruff,* 49 years old, is an Executive Vice President of the Company and the Regional President of Asia. Prior to his most recent position, Mr. Woodruff was Vice President of North America Business Development from September 2006 to March 2007 and was Vice President of AES for the North America West region from 2002 to 2006. Mr. Woodruff has held various leadership positions since joining us is 1992. Prior to joining us in 1991, Mr. Woodruff was a Project Manager for Delmarva Capital Investments, a subsidiary of Delmarva Power & Light Company. Mr. Woodruff holds a Bachelor of Science degree in Mechanical and Aerospace Engineering from the University of Delaware.**

Regulatory Matters

The Company is subject to complex energy, environmental and other governmental laws and regulations, both in the United States and in the other countries where it conducts business. These regulations affect most aspects of its business, including the development, ownership and operation of power generating facilities and in connection with the purchase and sale of electricity. The Company must also comply with applicable environmental and land use laws, rules and regulations.

Latin America

Argentina. In January and February 2002, the Argentine government adopted many new economic measures as a result of political, social and economic crisis. The new economic measures included: (i) the abandonment of the country s fixed dollar-to-peso exchange rate, (ii) the conversion of U.S. dollar denominated loans into pesos and (iii) the placement of restrictions on the convertibility of the Argentine peso. The regulations adopted in 2002 and 2003 in the energy sector effectively overturned the U.S. dollar based nature of the electricity sector. In the wholesale power market, electricity generators declared their costs of generation (which reflected their fuel costs) on a semi-annual basis. Under the current regulations, energy prices were partially converted from the original U.S. dollar denomination into Argentine pesos (pesified), following the pesification of the price of natural gas. However, the authorities permitted the production of cost for alternative fuels (fuel oil, coal) to reflect international costs. In order to avoid price increases associated with the use of alternative fuels, market regulations were changed so that the spot price is set considering only production costs declared with natural gas. Therefore, while generators receive remuneration for the use of alternative fuel, this cost is not considered when setting the spot price. Because of this, generation prices still reflect an artificially low fuel price, but due to the gas supply crisis and the subsequent agreement between the government and the gas producers to reset the prices, as described below, this effect has been offset and gas prices have returned to the levels of 2001 prior to the economic crises.

During 2004, the Energy Secretariat reached agreements with natural gas and electricity producers to reform the energy markets. The agreement with natural gas producers established a recovery path that increased wellhead prices to 80% of the original U.S. dollar price of 2001 by July 2005 and a second path that reached export parity by the end of 2006. In the electricity sector, the Energy Secretariat passed Resolution 826/2004, inviting generators to partially contribute their existing and future credits in the Wholesale Electricity Market (WEM) from January 2004 to December 2006 to fund the development and construction of two new combined cycle power plants to be installed by 2008/2009. In exchange, the Argentine government committed to reform the market regulation to match the pre-crisis rules prevailing before December 2001, including setting the capacity payment with a U.S. dollar reference and eliminating all regulations fixing an artificially low price in the wholesale market by 2009. As of May 31, 2005, the Argentine government reached an agreement on these reforms with more than 90% of generator companies. In October 2005, by Resolution 1193/2005 the Energy Secretariat and the power generators signed the final agreement for the management and operation of the projects intended to reset the electricity market. In February 2006, the Energy Secretariat approved the bylaws of the new companies, Termoelectrica General San Martin S.A. and Termoelectrica General Belgrano S.A. to be located in Timbues, next to Rosario city in Santa Fe province and in Campana city, Buenos Aires province, respectively. There can be no assurance, however, that the Argentine government will honor its commitment to release restrictive measures that it has placed upon wholesale prices after the new capacity is installed.

Under the previous regulations, distribution companies were granted long-term concessions (up to 99 years) which provided, directly or indirectly, tariffs based upon U.S. dollars and adjusted by the U.S. consumer price index and producer price index. Under the new regulations, tariffs are no longer linked to the U.S. dollar and U.S. inflation indices. The tariffs of all distribution companies were converted to pesos and were frozen at the peso national rate as of December 31, 2001. In October 2003, the Argentine Congress enacted Law No. 25,790, which established the procedure for renegotiation of the public utilities concessions and extended the period for that process until December 31, 2007. In combination, these circumstances create significant uncertainty surrounding the performance of the electricity industry in Argentina, including the Argentina subsidiaries of AES.

On November 12, 2004, EDELAP, an AES distribution business, signed a Letter of Understanding with the Argentine government in order to renegotiate its concession contract and to start a tariff reform process, which was ratified by the National Congress on May 11, 2005. Final government approval was obtained on July 14, 2005. As a first step during this process, a Distribution Value Added (DVA) increase of 28%, effective February 1, 2005, has been granted. Invoicing of the tariff increase commenced in August 2005. The Letter of Understanding also includes: (i) local cost adjustments to the tariff; (ii) elimination of penalties arising from potential energy supply shortages in Argentina; (iii) long-term payment terms for penalties owed to the customers; and (iv) other favorable conditions which are intended to benefit the company. The agreement was the first of its kind signed with UNIREN (Unit for the Renegotiation and Analysis of Public Services Contracts) in the Argentine electricity sector. Upon execution of the Letter of Understanding, AES agreed to postpone or suspend certain international claims; however, the Letter of Understanding provides that if the government does not fulfill its commitments, AES may re-start the international claim process. AES has postponed any action until the tarriff reset is finalized. On January 20, 2006, the Argentine regulator (ENRE) postponed the public hearing for the tariff review process; a new date for these processes has not been set. On October 24, 2005, EDEN and EDES, two AES distribution businesses in Argentina, signed a Letter of Understanding with the Ministry of Infrastructure and Public Services of the Province of Buenos Aires to renegotiate their concession contracts and to start a tariff reform process, which was approved by a Governor Decree on November 30, 2005. This Letter of Understanding includes the following:

(i) an initial 19% DVA increase effective August 2005, and an additional DVA increase which will be in force in accordance with National Government policies (8% DVA increase was granted effective January 1, 2007);

(ii) penalties recorded during the 2002 to 2005 period will not be paid;

(iii) Quality Service Regime penalties will be reduced; and

(iv) full tariff reset proceedings will be carried out in 2007 with a new tariff in force since February 2008.

This Letter of Understanding also includes other favorable conditions beneficial to these distribution facilities. AES agreed to postpone or suspend certain international claims; however, like the EDELAP Letter of Understanding, this Letter of Understanding provides that in case the government does not fulfill its commitments, AES may re-start the international claim process. AES has postponed any action with respect to international claims until the tariff reset is finalized.

Brazil. Under the present regulatory structure, the power industry in Brazil is regulated by the Brazilian government, acting through the Ministry of Mines and Energy (MME) and the National Electric Energy Agency (ANEEL), an independent federal regulatory agency which has exclusive authority over the Brazilian power industry. ANEEL s main function is to ensure the efficient and economic supply of energy to consumers by monitoring prices and ensuring adherence to market rules by market participants in line with policies dictated by the MME. ANEEL supervises concessions for electricity generation, transmission, trading and distribution, including the approval of applications for the setting of tariff rates, and supervising and auditing the concessionaires. ANEEL s core areas of responsibility that are directly related to AES s businesses are: economic regulation, technical regulation and consumer affairs oversight.

On December 11, 2003, the Brazilian government announced and proposed a new model for the Brazilian power sector (the New Power Sector Model) and enacted Provisional Measures #144 and #145, which set forth the basic rules that will govern the New Power Sector Model. On March 15, 2004, Law #10848 was enacted, which sets forth the basis of the new regulatory framework and general rules for power commercialization, regulated by Decree #5163, of July 30, 2004 and other administrative rulings.

The main points of the New Power Sector Model and its impact on AES businesses in Brazil are as follows:

- It creates two energy commercialization environments: (1) the regulated contractual environment (ACR), intended for the distribution companies, and (2) the free contract environment (ACL), designed for traders and free consumers.

- As of January 2005, every distribution utility is obligated to meet 100% of its anticipated energy requirements, subject to the application of penalties. Compliance with such obligation requires distribution companies to contract for energy through: (i) auctions of energy from new (proposed) generation projects; (ii) auctions of energy from existing generation facilities; and (iii) other sources, including public calls to purchase energy from distributed generation; renewable energy sources (through public auctions or the Brazilian Renewable Energy Incentive Program - PROINFA); pre-existing purchases made before Law #10848/04; and purchases from Itaipu.

- Distribution utilities can pass through up to 103% of their contracted load. ANEEL adopted a new pass-through methodology in the annual tariff adjustment; and variations of the energy purchase costs are reflected in a tracking account (CVA), which records the monthly price variations of non-manageable costs, both positive and negative, over the course of the year.

As part of the implementation process of the New Power Sector Model, distribution companies signed amendments to concession contracts, which modified a clause relating to the tariffs with respect to: (i) methodology of power purchase cost pass-through (mentioned above); and (ii) exclusion of PIS/COFINS (taxes over revenue).

The Electric Energy Commercialization Chamber (CCEE) carried out the largest auction in the country s history on December 7, 2004, in which power distribution utilities bought energy to serve 100% of their markets projected for 2005, 2006 and 2007 entering into the corresponding Regulated Power Purchase Agreements CCEAR. The Brazilian government inserted the rights for the CVA of energy purchased in the auctions into the concession contracts by an amendment to said contracts. The New Power Sector Model Law is currently being challenged on constitutional grounds before the Brazilian Supreme Court. To date, the Brazilian Supreme Court has not reached a final decision. Although the Company does not know when such a decision may be reached, the New Power Sector Model is currently in full force and it is very unlikely that it will be found unconstitutional.

In order to maintain the economic and financial equilibrium of the concession, utilities are entitled to the following types of tariff adjustments contemplated in the concession contracts:

- annual tariff adjustments;

- tariff reset; and

- extraordinary revisions, in the event of significant changes in concessionaires cost structure.

The primary purpose of the Annual Tariff Adjustment (IRT) is the maintenance of an adjusted tariff for inflation and the sharing of efficiency gains with consumers. The IRT uses a formula such that non-manageable (Parcel A) costs are passed through to the consumers and manageable (Parcel B) costs are indexed to inflation. An X-Factor is applied to capture the sharing of efficiency (scale) gains, effectively reducing the inflation index that is applied to Parcel B costs. The operations and maintenance costs considered in the tariff are based on the concept of a Reference Company, not on actual costs. In many cases, the Reference Company may not be reflective of distribution companies operating in Brazil and thus, underestimate true operating costs. ANEEL authorized an average adjustment of 11.45% (IRT) for Eletropaulo tariffs, effective July 4, 2006. The second tariff reset for Eletropaulo is scheduled for 2007, while the second tariff reset for Sul is scheduled for 2008.

AES s business in Brazil is still attempting to resolve certain regulatory issues relating to a rationing program instituted in 2001. Specifically, on December 21, 2001, the President of Brazil issued a provisional measure which provided general authorization for: (i) pass-through to consumers of costs incurred by generators for the purchase of energy at spot prices during the rationing program and (ii) recovery in future years of revenue losses sustained by distributors during the rationing period, through an Extraordinary Tariff Adjustment (RTE). ANEEL, through a resolution issued on January 12, 2004, established AES Eletropaulo s RTE recovery period at 70 months and stated that Parcel A recovery will happen only after the RTE recovery.

AES Sul is pursuing the annulment of ANEEL s Order 288, May 16, 2002, in which ANEEL retroactively prohibited several companies, AES Sul included, the opportunity to choose not to participate in the exposition relief mechanism, which allowed these companies to sell the energy from Itaipu into the spot market. This lawsuit has a financial impact of about R$373 million (historic values referring to 2001). AES Sul was granted a preliminary injunction ordering ANEEL to review CCEE s accounts. This lawsuit awaits the judge s decision regarding ANEEL s petition to include CCEE as a participant in the lawsuit. If a settlement occurs with the effect of Order # 288 in place, AES Sul will owe a net amount of approximately R$80 million (historic values referring to 2001). If AES Sul is unsuccessful and unable to pay any amount that may be due to CCEE, penalties and fines could be imposed up to and including the termination of the concession contract by ANEEL. AES Sul is current on all CCEE charges and costs incurred subsequent to the period in question in the Order # 288 matter. All amounts, including the amount owed to CCEE in the event AES Sul loses the case, are reserved in AES Sul s books.

AES concession agreement with the State of Sao Paulo for the Tiete generation plant includes an obligation to increase generation capacity by 15% by the end of 2007. It is anticipated that AES, as well as other concessionaire generators, will not be able to meet this requirement due to regulatory and hydrological conditions making the increase impossible. The matter is under consideration by the State Government of São Paulo. AES is seeking to resolve the issue through an extension of the deadline or other options. An adverse decision by the regulator could have a negative impact of on the value of the plant, but at this time the positions of ANEEL and the State of Sao Paulo are not known.

On February 13, 2007 ANEEL issued Resolution #250/07 in order to clarify and regulate the provisions of a 2003 law (Law #10762/03), which had not yet been interpreted by ANEEL. This new resolution establishes guidelines for dividing costs associated with new connection (or load increase) requested by customers, between the distribution company and the corresponding customers. AES is still evaluating the full effect of this new resolution.

Chile. In Chile, the regulation of production schedules for electricity generation facilities is based on the marginal cost, which is the variable cost of the least expensive next unit required by the system at any time. Chile has four electricity systems. The major two interconnected electricity systems are the Central Interconnected System (*Sistema Interconectado Central*) (SIC) and the Northern Interconnected System (*Sistema Interconectado del Norte Grande*) (SING), which cover almost 97% of the population of the country.

The electricity market in Chile is divided into three distinct segments, generation, transmission and distribution. The regulatory framework was enacted in 1982, and the underlying foundation has remained unchanged, except for amendments which have focused on providing clarifications and additional incentives to market participants.

Based on the Chilean electricity market framework, two electricity markets coexist: 1) a primary contract market for transactions between generators and customers, and 2) a secondary spot market for the exchange of energy and firm capacity among generators. In the primary market, customers, including regulated distribution companies and unregulated customers are obligated to enter into long-term power purchase agreements, which specify the volume and financial terms associated with the sale of energy and capacity.

In the secondary market, the independent system operator (CDEC) in each system dispatches the plants in order to have, at any specific level of demand, the appropriate supply at the lowest possible marginal cost of production available in the system, considering transmission and reliability constraints.

As a result, generation companies are free to enter into sales contracts with distribution companies and other customers for the sale of capacity and energy. However, the electricity necessary to fulfill these contracts is provided by the contracting generation company only if the generation company s marginal cost of production is low enough for its generating capacity to be dispatched to meet demand. Otherwise, the generation company will purchase electricity from other generation companies at the marginal cost of the system, which is lower than the production cost of the company.

The prices paid to generation companies by distribution companies for capacity and energy to be resold to their retail customers are, pursuant to law, based on the expected average marginal cost of capacity or energy. In order to ensure price stability, however, the regulatory authorities in Chile established node prices to be set every six months for energy and capacity requirements of regulated consumers paid by distribution companies. Node prices for energy are calculated on the basis of the projections of the expected marginal costs within the system over the next 24 to 48 months, in the case of the SIC and the SING. The formula takes into account, among other things, assumptions regarding available supply and demand in the future. Node prices for capacity are based on the marginal investment required to meet peak demand, based on the cost of a diesel-fired turbine. Prices for capacity and energy sold to large customers (over 0.5 MW) and other generation companies purchasing on a contractual basis are unregulated and are often set with reference to node prices, alternative fuel prices, exchange rates and other factors. If average prices for capacity and energy sold to non-regulated customers differ from node prices by more than a defined percentage (5%-30%, calculated pursuant to regulations), node prices are adjusted upward or downward, as the case may be, so that the difference between such prices equals such percentage.

On March 13, 2004, Law No. 19.940 was enacted establishing amendments to the existing Electricity Law, principally in relation to tolls charged for the use of high voltage network and transmission systems. The reduction of the minimum demand required to be considered as an unregulated customer went from 2 MW to 0.5 MW. In addition, other factors considered are the reduction of the floating band for regulated price from 10% to 5%, the incorporation of elements to create an ancillary services market and the pricing mechanism for small and medium-sized electricity systems. The modifications contained in Law No. 19.940 maintain or improve the Company s position with regard to both the Company s current status and projected development and, in particular, with regard to the issues related with transmission tolls. In addition, the Regulations to the Electricity Law, Supreme Decree No. 327, which was modified on October 9, 2003 with respect to the clarification of the methodology utilized to calculate transmission tolls, has been replaced by Law No. 19.940.

On March 25, 2004, the Argentine government published Resolution 265, which privileged the domestic supply of natural gas, immediately affecting the export of natural gas to neighboring countries (primarily Chile). However, this resolution provided suppliers with alternative means of supply under existing export contracts. Between April and June 2004, daily export restrictions to Chile fluctuated between 20% and 47% of contracted volumes, depending on domestic demand. At the end of 2004, the curtailments were less than 10% due to improved hydrological conditions in Argentina and Chile, and increased availability of Bolivian gas.

This situation changed at the beginning of 2005 when as a result of high electricity demand and natural gas consumption in Argentina, in addition to the policy established by Compañia Administradora del Mercado Eléctrico (CAMMESA) to conserve water under Resolution 839, the curtailments increased during summer months reaching a peak of almost 50%, equivalent to 402 Mmcf/d at the end of May 2005. From May until September 2005, the daily export restrictions to Chile fluctuated between 40% and 10%. In the last quarter of 2005, the restrictions were reduced by 7% to 12%, mainly due to improved hydrological conditions compared to the beginning of the year.

Electrica Santiago, a subsidiary of the Company, produces electricity by burning natural gas produced in southern Argentina which is transported to central Argentina through a pipeline owned by Transportadora Gas del Norte S.A., or TGN, and then to Chile. The TGN pipeline supplies consumers in Argentina and Chile. Interruptions in the supply and/or transportation of natural gas by TGN would adversely affect the operations and financial condition of Electrica Santiago. Such potential interruptions would materially impair Electrica Santiago s ability to generate electricity and would force it to rely on the spot market to purchase electricity to meet its contractual commitments. Furthermore, because all combined-cycle plants in the SIC use the same pipeline to obtain their natural gas supplies from Argentina, a disruption of this supply would materially increase prices in the spot market. The reliance on the spot market to purchase electricity could have a material adverse effect on Electrica Santiago.

On May 3, 2005, a bill to amend the Electric Law was approved by the Chilean congress which was promulgated by the executive branch on May 19, 2005 (Law No 20.018). The bill was designed to mitigate the effects of the restrictions on natural gas exports to Chile, which have been applied by the Argentine government since March 2004. The main aspects of Law 20.018 include:

- implementation of public bid processes for distribution companies for their consumptions starting after 2009;
- modification of regulated node price methodology, progressively replacing the node price with public bid prices and improvement in the correlation between regulated node prices and unregulated market prices in the interim period;
- stabilization of generation companies revenues by allowing them to enter into long-term fixed price contracts with distribution companies (maximum of 15 years);
- authorization of voluntary savings incentives which allow generation companies to directly negotiate demand reductions with final customers;
- determination that natural gas shortages can no longer be considered force majeure events and compensation to customers by generation companies which fail to operate due to gas shortages; and
- establishment of compensation for losses by generation companies when obligated to sell to distribution companies that are unable to independently contract adequate supplies.

These changes produced an improvement in the regulatory framework by reducing the risks of arbitrary regulatory intervention and creating a better investment environment. The first bid process was successfully carried out in October 2006. In November of 2006, Gener was awarded 1,355 GWH in the recent bidding process held by the electricity distribution companies.

Colombia. In 1994 the Regulatory Commission of Electricity and Gas (CREG) was created to foster the efficient supply of energy through regulation of the wholesale market, the natural monopolies of transmission and distribution, and by setting limits for horizontal and vertical economic integration. The control function was assigned to the Superintendency of Public Services. The Mining and Energy Planning Unit (UPME) develops plans for the energy sector. These plans are then adopted by the Ministry of Mines and Energy. In addition to other initiatives, the general regulatory framework established free access in the networks, free entrance in the business, the creation of a wholesale market, the unbundling of activities, the principles for setting formulas for tariffs and the free selection of the provider by the consumer.

The wholesale market is organized around both bilateral contracts and a mandatory pool and spot market for all generation units larger than 20 MW. Each unit offers its availability quantities for a 24 hour period with one price set for those 24 hours. The dispatch is arranged by price merit, and the spot price is set by the marginal unit. The system is one node.

Colombia s spot market began in July 1995, and in 1996 a capacity payment was introduced for a term of 10 years. In December 2006, Regulation 071 was enacted which replaced the capacity charge with a reliability charge. This new charge has been in place since December 2006 and is expected to have a positive impact on Chivor for 2007 of US$15.5 million compared to the US$18.3 million that it received in 2006. Under the reliability charge mechanism, plants present firm energy price and volume offers in public auctions that are held three years prior to the initiation of supply. Plants are allowed to bid up to the maximum firm energy level which can be provided during drought conditions, as defined in a methodology utilized by the CREG. The new regulation includes a transition period from December 2006 to November 2009, during which the price is equal to US$13 per MWh and volume is determined based on firm energy offers which are pro-rated so that the total firm energy level does not exceed system demand.

Bilateral contracts between a generator and suppliers are treated as financial instruments which are settled by the Market Administrator. These contracts are normally either take or pay or take and pay agreements, and normally have a term of one to three years. There is no regulatory obligation for an electricity supplier to hedge its consumers demand, and the negotiation of energy contracts between generators and suppliers for unregulated customers is unrestricted. The contracts to supply energy to regulated (small) consumers must be assigned by the Load Servicing Entities (LSE) through a public bidding process to determine the lowest offer.

Dominican Republic. The General Electricity Law No. 125-01 was passed on July 26, 2001. New institutions were created to formulate energy policy and regulate the sector, including the Energy National Commission (CNE) and the Superintendancy of Electricity (SIE). However, some of the new resolutions adopted by SIE are in conflict with the regulations created by the Ministry of Industry and Commerce prior to enactment of Law 125-01.

During 2004, an increase in fuel prices caused a financial crisis in the Dominican Republic electrical sector. Specifically, the inability to pass through higher fuel prices and the costs of devaluation led to a gap between collections at the distribution companies and the amounts required to pay generators for electricity generated. The election of a new presidential administration in August 2004 has been accompanied by progress towards addressing the crisis in the electricity sector. Negotiations have intensified between the government, the multilateral lending and development agencies such as the IMF and the World Bank and the private electricity sector. The key issues that are the focus of these negotiations include (i) the failure to provide for full pass-through of the costs of electricity supply to consumers; (ii) the failure of the regulator to follow through on subsidy commitments, which has put the distribution companies in the position of effectively financing portions of the subsidy programs; and (iii) the fiscal deficit of the government of the Dominican Republic which requires multilateral lending to reconstitute the sector.

During 2006, the Dominican Republic government has been paying both the subsidies and its own energy bills on time; the tariff has been modified to recognize the fuel generation basket, and there is increased support for fraud prosecution. Despite this improvement over prior years, the electricity sector has not completely recovered from the financial crisis of 2004. Last year it needed more then US$500 million to cover the current operations, and for 2007 an amount of US$400 million has been included in the budget, which indicates that the electricity sector in the Dominican Republic remains fiscally unstable, so that additional reforms may be needed.

In December 2006, the Executive branch sent to congress a bill modifying the General Electricity Law. The bill criminalizes theft of electricity and simplifies the process that the Distribution companies must follow in order to detect and document fraud in the electric networks. The legislation will be considered and could be approved in the first quarter of 2007.

El Salvador. In 1996, the government of El Salvador created a new regulatory framework through the enactment of the Electricity Law in October of 1996, as amended in June 2003. The Electricity Law regulates the generation, transmission, marketing, distribution and supply of electricity in El Salvador and provided the basis for private sector participation and competition in the Salvadoran energy sector, the unbundling of electricity generation, transmission and distribution, the privatization of electricity distribution and generation assets and the creation of a transparent regulatory structure.

Under the Electricity Law, an independent regulator, Superindencia General de Electricidad y Telecomunicaciones (SIGET), was established, and the country s pubic electric company, Comisión Ejecutiva Hidroeléctrica de río Lempa (CEL) was required to reorganize its generation, transmission and distribution assets to facilitate privatization. CEL separated its generation, transmission and distribution activities from one another and further divided its generation and distribution activities into operationally independent companies for purposes of privatization.

El Salvador has five electricity distribution companies. AES controls four of these five distribution companies: CAESS, CLESA, EEO, and DEUSEM, which include rural electrification activities that were situated near the networks of these companies.

The government has recently adopted certain revisions and adjustments to the regulatory system created by the Electricity Law, and additional modifications are under consideration. The government is studying how to further separate the activities of CEL and El Salvador Electricity Transmission Company (ETESAL), the transmission company that is owned by CEL, with the goal of privatizing ETESAL. In addition, new Salvadoran regulations have been recently issued aimed at facilitating the entry of electricity traders into the electricity market and improve the transparency of the pricing signals in the wholesale market.

In June 2003, the government amended the Electricity Law to grant greater regulatory authority to SIGET and to create a compensatory fund in the wholesale market to promote stability in the price of energy on the spot market. SIGET has recently prepared norms and guidelines in the form of a manual, which will set minimum standards for electricity distribution companies for system design, distribution losses and costs, as well as service quality and reliability. In addition, as part of the Company s regular upcoming five-year tariff review process, SIGET is reviewing the characteristics of the demand curve for each of the Company s electricity distribution networks, in order to be able to better analyze and review the Company s proposed tariffs.

During 2005, the Ministry of Economy (Ministerio de Economía) proposed revising the dispatch rules for El Salvador s electricity market from a bidding to an economic dispatch basis. If this reform is adopted in the future, it may adversely affect the Company s ability to continue to generate margins on the energy it buys and sells for its customers. The proposal remains under discussion.

Panama. In 1995, Panama initiated the reform of its electricity sector with the passage of legislation allowing private participation in power projects. This was followed in 1996 by the Public Services Regulatory Agency Law, which established new institutional arrangements for the regulation of public services, including electricity. In 1997, the Electricity Law was passed, calling for the restructuring of the Instituto de Recursos Hidráulicos y Electrificación (IRHE), the Panamanian government agency responsible for electricity generation, transmission and distribution. IRHE was divided into three distribution companies, four generation companies and one transmission company for privatization.

In 1998, the country s three distribution companies were privatized, and were each granted 15-year concessions. The same year, the four generation companies were privatized, with the hydropower generators receiving 50-year concessions granting the use of water, and the thermal power generators receiving 40-year licenses. The transmission company remains under state ownership.

The dispatch of the system is the responsibility of the Centro Nacional de Despacho (CND), which is part of the transmission company, Ente Regulador de los Servicios Públicos (ETESA or the Regulator). There is a surcharge levied on revenues in the system to cover the administrative costs of the CND and ETESA, which helps to promote the Regulator s political independence. The regulatory framework establishes the operation of generation plants on a merit-order dispatch basis. Dispatch priority is determined based on audited variable operating costs with the last unit dispatched determining the marginal cost of the system. Hydroelectric plants are dispatched in such a way as to optimize the use of water.

The Panamanian electric system operates with both contract and spot markets. At the time of privatization, the distribution companies were assigned Power Purchase Agreements (PPAs) with each of the generators, sufficient to meet the generators peak energy demand requirements. The cost of electricity with respect to spot market purchases and PPAs approved by the electric industry regulator (including initial and new contracts) are a direct pass-through to residential and industrial users. The system is designed to preserve the financial health of the distribution companies and the entire electricity sector. Distribution companies are required to contract 100% of their annual energy requirements (although they can self-generate up to 15% of their demand), reducing uncertainty for generators and consumers. Tariffs were increased in 2003 and 2004, and the government subsidized a 2005 tariff increase.

North America

United States. The federal government regulates wholesale power markets and transmission facilities in most of the continental U.S., while each of the fifty states regulates retail electricity markets and distribution. Over the past decade, there have been a number of federal and state legislative and regulatory actions that have altered how energy markets are regulated. A series of regulatory policies have been adopted in the United States by both the federal government and the individual states that encourage competition in wholesale and retail electricity markets.

Federal Regulation of Electricity

The FERC has ratemaking jurisdiction and other authority with respect to interstate wholesale sales and transmission of electric energy under the Federal Power Act (FPA) and with respect to certain interstate sales, transportation and storage of natural gas under the Natural Gas Act. In 1996, the FERC issued Order # 888, which mandated the functional separation of generation and transmission operations and required utilities to provide open access to their transmission systems. Each utility under the FERC s jurisdiction was required to file an Open Access Transmission Tariff. In 2000, the FERC issued Order # 2000, which established the functions and characteristics of Regional Transmission Organizations (RTOs) as a means to ensure independent administration of the open access policy and to help increase investment in transmission infrastructure. On a regional basis RTOs assume functions traditionally handled by individual utilities, such as transmission access, security, coordination and planning. RTOs have been created and currently administer the interconnected transmission system in a number of the markets in which AES owns electric generation such as California and the Midwest.

Beginning in the fall of 2001, regulatory officials in the United States began to re-examine the nature and pace of deregulation of electricity markets. This re-examination was primarily the result of extreme price volatility and energy shortages in California and portions of the western markets during the period from May 2000 through June 2001. The conclusions reached in this re-examination have not been uniform, but rather have differed from state to state and between the federal government and the states themselves. Thus, a number of states have advocated against restructuring and abandoned any efforts to proceed with deregulation of retail markets, while the FERC has continued its efforts to enhance open access electric transmission and enhance competition in bulk power (wholesale) markets, albeit at a somewhat slower pace. This has led to a number of confrontations and legal proceedings between the FERC and the states over jurisdiction. The Company believes that over the next decade the United States will continue to resemble a patchwork quilt of differing regulatory policies at the retail level.

The Federal government, through regulations promulgated by the FERC, has primary jurisdiction over wholesale electricity markets and transmission services. Since 1986, the FERC has approved market based rate authority for many providers of wholesale generation, and the mix of market players since then has shifted toward non-utility entities, generally referred to as Independent Power Producers (IPPs), whose rates are negotiated rather than based on costs. The FERC has issued a number of orders that increase the reporting requirements of entities requesting market based rate authority. In May 2006, the FERC issued a rulemaking concerning the four criteria examined in granting market based rate authority and the resulting regulations may result in a somewhat more stringent analysis for obtaining such authority. Recently utilities have begun supplying their own generation again, through affiliate contracts, acquisition of distressed assets and traditional utility construction. These assets are generally included in base rate, and the building of generation by utilities represents a move back to traditional cost of service ratemaking regulation.

On August 8, 2005, the President signed into law the Energy Policy Act of 2005 (EPAct 2005). The legislation repealed the Public Utility Holding Company Act (PUHCA of 1935) and replaced it with the Public Utility Holding Company Act of 2005 (PUHCA of 2005), which became effective on February 8, 2006. The repeal of the PUHCA of 1935 removed utility holding companies from the jurisdiction of the SEC and greatly reduced the financial, organizational and line of business restrictions imposed on utility holding companies. The PUHCA of 2005 increases federal and state access to books and records, but does not restrict mergers and acquisitions of non-contiguous utilities as did the previous law.

Under Section 203 of the FPA, as amended by EPAct 2005, the FERC has increased authority to review mergers and acquisitions, including acquisitions of foreign utility companies. However, the FERC has issued regulations that give a holding company that owns a transmitting utility or an electric utility company and has captive U.S. customers (such as AES) blanket authority to acquire a foreign utility company upon making a notice filing containing specific certifications with respect to the protection of such customers from the effects of the acquisition.

EPAct 2005 also provides the FERC with new authority to certify an Electric Reliability Organization (ERO) that will set mandatory reliability standards for the U.S. grid. On April 4, 2006 the National Energy Regulatory Commission (NERC) filed an application for certification as the ERO and a petition for approval of 102 Reliability Standards. The NERC was certified as the ERO on July 20, 2006, and the FERC initiated a rulemaking to review and approve the Reliability Standards. Although NERC has not historically had authority to mandate compliance with reliability standards, utilities generally choose to voluntarily comply with the standards. The new legislation gives the ERO the ability to create mandatory standards and would grant the ERO authority to enforce these standards through the issuance of financial penalties.

Finally, EPAct 2005 amends the Public Utility Regulatory Policies Act of 1978 (PURPA) and instructs the FERC to promulgate regulations to implement the amendments. Pursuant to this directive the FERC has issued a final rule that: (i) prescribes new restrictive criteria that new cogeneration facilities must meet in order to be designated as qualifying facilities (QFs) under PURPA; (ii) removes the restrictions on ownership of QFs by an entity that is primarily engaged in the generation or sale of electric power; and (iii) for new QFs eliminates certain regulatory exemptions that QFs previously received. On October 20, 2006, the FERC issued a final rule that effectively removes the requirement that utilities enter into new contracts to purchase energy and capacity produced by QFs having capacity greater than 20 MW if the utilities are located within the control areas of the Midwest Independent Transmission System Operator, Inc. (Midwest ISO), PJM Interconnection, L.L.C., ISO New England, Inc., the New York Independent System Operators or ERCOT. Utilities located in other regions of the United States must file a request to be relieved of the purchase obligation and the FERC will decide on a case by case basis whether QFs have access to competitive wholesale markets, and therefore, no longer require a mandatory buyer. We believe that the new rule will not have a material impact on the Company s existing contracts.

On September 21, 2006, the FERC conditionally approved the California Independent System Operator s (CAISO) tariff filing to reflect Market Redesign and Technology Upgrade (MRTU). The new market design is scheduled to go into effect on November 1, 2007 and will include location based marginal pricing and a financially binding day-ahead energy market. The Company believes that the MRTU will not have a material impact on its existing facilities due to long-term contracts that remain in place. In August 2000, the FERC announced an investigation into the organized California wholesale power markets in order to determine whether rates were just and reasonable. Further investigations involved alleged market manipulation. See *Item 3. Legal Proceedings* in this Form 10-K.

In addition to the FERC regulation described above, IPL is subject to regulation by the Indiana Utility Regulatory Commission (IURC) as to its services and facilities, the valuation of property, the construction, purchase, or lease of electric generating facilities, the classification of accounts, rates of depreciation, retail rates and charges, the issuance of securities (other than evidences of indebtedness payable less than twelve months after the date of issue), the acquisition and sale of public utility properties or securities and certain other matters.

IPL s tariff rates for electric service to retail customers (basic rates and charges) are set and approved by the IURC after public hearings. Such proceedings, which have occurred at irregular intervals, involve IPL, the staff of the IURC, the Indiana Office of Utility Consumer Counselor and other interested consumer groups and customers. Pursuant to statute the IURC is to conduct a periodic review of the basic rates and charges of all utilities at least once every four years.

The majority of IPL customers are served pursuant to retail tariffs that provide for the monthly billing or crediting to customers of increases or decreases, respectively, in the actual costs of fuel consumed from estimated fuel costs embedded in basic rates, subject to certain restrictions on the level of operating income. In addition IPL s rate authority provides for a return on IPL s investment and recovery of the depreciation and operation and maintenance expenses associated with the nitrogen oxide (NOx) compliance construction program and its multipollutant plan.

IPL participates in the restructured wholesale energy market operated by the Midwest ISO. The implementation of this restructured market marks a significant change in the way IPL buys and sells electricity and schedules generation. Prior to the restructured market, IPL dispatched its generation and purchased power resources directly to meet its demands. In the restructured market IPL offers its generation and bids its demand into the market on an hourly basis. The Midwest ISO settles these hourly offers and bids based on location based marginal prices or LMPs, i.e., pricing for energy at a given location based on a market clearing price that takes into account physical limitations, generation and demand throughout the Midwest ISO region. The Midwest ISO evaluates the market participants energy injections into, and withdrawals from, the system to economically dispatch the entire Midwest ISO system on a five-minute basis. Market participants are able to hedge their exposure to congestion charges, which result from constraints on the transmission system, with certain Financial Transmission Rights, or FTRs. Participants are allocated FTRs each year and are permitted to purchase additional FTRs. As anticipated and in keeping with similar market start-ups around the world, LMPs are volatile, and there are process, data, and model issues requiring editing and enhancement. IPL and other market participants have raised concerns with certain Midwest ISO transactions and the resolution of these items could impact our results of operations.

Europe & Africa

European Union. European Union (EU) member states are required to implement EU legislation, although there is a degree of disparity as to how such legislation is implemented and the pace of implementation in the respective member states. EU legislation covers a range of topics which impact the energy sector, including market liberalization and environmental legislation. The Company has subsidiaries which operate existing generation businesses in a number of countries which are member states of the EU, including the Czech Republic, Hungary, the Netherlands, Spain and the United Kingdom. The Company also has subsidiaries which are in the process of constructing a generation plant in Bulgaria. Bulgaria became a member of the EU as of January 2007 and will, upon accession to the EU, be subject to EU legislation.

The principles of market liberalization in the EU electricity and gas markets were introduced under the Electricity and Gas Directives (Directive 1996/92/EC and Directive 1998/30/EC, respectively). In 2005, the European Commission (EC), the legislative and administrative body of the EU, launched a sector-wide inquiry into the European gas and electricity markets. In the context of the electricity market, the inquiry has to date focused on identifying problems related to price formation in the electricity wholesale markets and the role of long-term agreements as a possible barrier to entry with a view to improving the competitive situation. The Hungarian Competition Authority launched a parallel inquiry into the national electricity and gas market and announced its preliminary findings in late 2005. These preliminary findings identified long-term contracts as a potential source of competition concern, in addition to other obstacles, such as having a single power buyer, the Hungarian Power Companies LTD (MVM). The EC has commenced a formal investigation into long-term power purchase contracts in Hungary, including the long-term power purchase contract entered into between AES Tisza Eromu Kft (AES Tisza) and the state owned electricity wholesaler, MVM. See Hungary below, for details of this investigation. In addition, the EC has launched an independent investigation into alleged abusive practices on the part of MVM.

The EC has also introduced environmental legislation which impacts the electricity sector in general and includes:

- The EU Directive on Integrated Pollution Prevention and Control (1996/61/EC) (IPPC Directive) which requires member states to prevent or reduce pollution from a range of installations including electricity generation stations and introduces a permit regime to ensure the prevention or reduction of pollution from such installations.

- The Large Combustion Plants Directive (2001/80/EC) (LCPD) which introduced a regime for the reduction of emissions sulphur dioxide, nitrogen oxides and particulates from large combustion plants, with increased restrictions coming into effect in two phases from 2008 and 2016, respectively.

- The Renewables Directive (2001/77/EC) which deals with the promotion of electricity generated from renewable sources and sets a target of 12% of electricity consumed in the EU to be generated from renewable sources by 2010.

- The EU Emissions Trading Directive (2003/87/EC) which, among other things, established the EU Emissions Trading Scheme (EUETS) in respect of emissions of carbon dioxide effective January 1, 2005.

Progress in the implementation of the directives referred to above varies from member state to member state. AES generation businesses in each member state will be required to comply with the relevant measures taken to implement the directives. See Air Emissions below, for a description of these Directives.

Hungary. In 2004, in connection with the accession of Hungary as a member state of the EU, the Hungarian government provided notification to the EC of certain legislative arrangements concerning compensation to the state owned electricity wholesaler, MVM. The EC conducted a preliminary investigation to determine whether or not any alleged government aid was provided through MVM to its suppliers which was incompatible with the common market. The EC decided to open a formal investigation in 2005. AES Tisza is not a named party to the investigation, but could be adversely affected in the event that the EC concludes that AES Tisza is one of the beneficiaries of unlawful state aid by virtue of its power purchase arrangements with MVM. As an interested party, AES Tisza has made submissions to the EC in relation to the investigation. If the EC reaches a formal conclusion that the long-term power purchase arrangements are contrary to applicable EU law, it can require the Hungarian authorities to recover any aid involved. It is for the Hungarian authorities to execute the EC s decision in accordance with national law. The authorities may then seek to revise the contracts and/or require the repayment of certain funds received by generators pursuant to the contracts. It is not currently known whether the underlying contracts, including the contract with AES Tisza, will be revised or terminated or what reimbursement and/or compensation will be payable in connection with their revision or termination. Although the EC has not yet completed its formal investigation or published its conclusions, the Commissioner for Competition has indicated informally that she considers the long-term power purchase arrangements to be contrary to applicable EU law and has encouraged the Hungarian government to terminate the long-term power purchase arrangements.

In early 2006, the Hungarian government enacted legislation to amend the Hungarian Electricity Act (Act 110 of 2001) to enable, among other things, the application of administrative pricing to the sale of electricity by generators to the state owned utility wholesaler, MVM. Implementing legislation was subsequently issued in November 2006 re-introducing administrative pricing which purports to impose a regulated price on the sale of electricity by generators, including AES Tisza, to the public utility sector. The regulated price is lower than that specified in the existing long-term power purchase agreement between AES Tisza and MVM. AES Tisza is in the process of assessing the implications of this legislation, including the impact on its current power purchase and financing arrangements and the ability of AES Tisza to challenge the re-introduction of administrative pricing by the Hungarian government.

Kazakhstan. The Government of Kazakhstan has implemented a series of regulatory normative acts to encourage competition in wholesale and retail electricity markets.

Under the present regulatory structure, the electricity generation and supply sector in Kazakhstan is mainly regulated by the Ministry of Energy and Mineral Resources (the Ministry), the Committee for protection of competition of the Ministry of Industry and Commerce (the Committee) and the Agency for regulation of the natural monopolies (the Agency). Each has the necessary authority for the supervision of the Kazakhstan power industry. However, because of certain contradictions between different regulations and the absence of a clear demarcation between rights and responsibilities of the Ministry, the Committee and the Agency, there is some uncertainty in the regulatory environment of the power sector.

The Ministry s main function is to supervise the appropriate implementation of the Electricity Law (Law of Kazakhstan On Power Industry No. 588-II dated July 9, 2004) and other rules and regulations in the power sector, ensure the efficiency of the wholesale and retail power markets and ensure reliability of power supply through technical monitoring and licensing requirements.

The Committee s authority arises under the Competition Law (Law of Kazakhstan On competition and monopoly activity restriction No. 173-III dated July 7, 2006), which authorized the antimonopoly body to issue approval in connection with large mergers and acquisitions, to monitor markets for monopolistic activity and competition protection and to control tariffs of dominant entities in different sectors of economy including wholesale and retail electricity markets.

The Agency s main function, as is defined in the Natural Monopoly Law (Law of Kazakhstan On natural monopolies No. 272-I dated July 9, 1998), is to approve and regulate the tariffs of the natural monopolists (including heat generation, power transmission and distribution), to supervise the activity of the natural monopolists with respect to their investment policy and quality of services and provide customer protection.

Kazakhstan has a wholesale power market, where generators and customers are free to sign contracts at negotiated prices. Power generating entities and retail supply companies are required to participate in the centralized power trade with some minimum required volumes set by the Ministry (up to 30% for generation companies and up to 50% for retail supply companies). State-owned entities and natural monopolies are obligated to buy power through tenders and centralized trading. The wholesale transmission grid is owned by state-owned company KEGOC, which also acts as the system operator.

Starting in 2004, Kazakhstan introduced a retail market, as a result of which distribution companies had to transfer retail power supply functions to newly created retail companies. During a transition period retail prices are controlled by the Committee, though the government program resumes introduction of competitive retail pricing in the near future.

Two hydro plants which are under AES concession, Kazakhstan s Ust-Kamenogorsk Hydro Plant (UK Hydro) and Kazakhstan s Shulbinsk Hydro Plant (Shulbinsk Hydro), together with AES Kazakhstan Ust-Kamenogorsk CHP Hydro Plant (UK CHP), all located in the Eastern Kazakhstan region, are recognized by the Committee as dominant entities in the regional market because their aggregated share in the electricity supply commodity market in the region is 70%. These businesses are required to notify the competition authority about any power price increases for regional customers. Nurenergoservice LLP and DostykEnergo LLP are two AES trading companies that participate in the Kazakhstan power markets, both of which may face regulation by the Committee relating to resale of power to customers located in Eastern Kazakhstan.

In February 2007, the Committee initiated administrative proceedings against UK Hydro and Shulbinsk Hydro for allegedly using Nurenergoservice LLP to increase power prices for Eastern Kazakhstan customers in alleged violation of Kazakhstan s antimonopoly law. See Item 3. Legal Proceedings in this Form 10-K

Ukraine. In 1995, Ukraine began restructuring the electrical energy sector from a single vertically integrated system operated by the Ministry of Energy and Electrification to a more regionalized system. In the revised system generation, local distribution and high voltage transmission were removed from the vertically integrated system. Local distribution and supply services were placed into 27 regionally defined operating companies. The Ministry of Energy and Electrification remained as a policy agency and also controlled shares (assets) of state joint stock companies. The President of Ukraine also created the NERC, which was to ensure the effective functioning of the electric energy sector and the formation of an electric energy market.

Since 1996, the Ukrainian energy market operates in a wholesale energy market model, under which AES Ukraine procures electricity from the wholesale energy market (hereinafter WEM) at the hourly spot process. One of the pre-conditions for privatization of the distribution companies in 2001 set forth by the government was repayment to the WEM of the historical debt of companies to be privatized by the investor over 5 years following privatization. In July 2005, the government issued a special resolution by which government debts to the population resulting from the default of Soviet banks could be offset against populations debts for purchased electricity by means of so called checks . This resolution allowed AES Ukraine to offset part of doubtful residential customers receivables against its payables to the wholesale electric market for purchased power. In April 2006, a new Cabinet of Ministers resolution was issued to amend the checks scheme allowing AES Ukraine to offset the last portion of the restructured debt to wholesale market with checks that were collected from customers as payment of their electricity bills. Thus, AES Ukraine paid the last portion of the restructured debt using this offset mechanism rather than cash. In 2006, AES Ukraine successfully repaid the restructured debt owed to the WEM by both of its businesses and became the first entity to be free of debt to the WEM in the country.

Due to Parliamentary elections in 2006, significant staff changes took place in the key regulatory agencies. In particular, new Minister of Energy and National Energy Regulatory Commission (NERC) Chairman were appointed. NERC twice authorized 25% increases in end user tariffs for residential customers in 2006. A further increase to reach the actual cost of service for residential customers is expected in 2007.

In October 2006, NERC proposed a new methodology for calculating wages and salaries which could result in an increase of about 25% in the tariff allowance for wages and salaries. NERC also initiated the idea of introducing social tariffs for residential customers whose consumption is at or below 125 kWh/month and inclining block tariffs for residential customers are scheduled for implementation in April 2007. These social tariffs are designed to improve affordability for low-use customers. In combination with the inclining block tariff, the mechanisms should create an incentive for customers to manage their consumption. In all, the hope is that these measures reduce default rates and improve overall collection rates. However, it still remains to be determined how the system will work in practice.

During 2006, the wholesale electricity market price increased approximately 17% due to increases in fuel prices and changes in the pricing arrangements for thermal generating companies.

Regulations addressing various aspects of AES Ukraine activity that have been amended and/or drafted in the course of 2006 include:
(i) electricity usage codes for legal and residential customers; (ii) connection to network fee methodology; (iii) methodology for calculation of the value of illegally consumed electivity; and (iv) tender procedure to be applied by distribution and supply companies.

The Company expects that the tariff methodology applied for calculation of AES Ukraine tariffs is going to evolve in 2007 according to methodology provisions approved in 2001, as a result of which: (i) rate of return on new investment will decrease from 17% after tax to about 14% and (ii) technical and commercial loss allowances will decrease. In 2008, it is expected that (i) the rate of return on initial investment will be revised with a floor of 11%; (ii) commercial losses will not be allowed in the tariff; and (iii) the black box of operational expenses fixed in 2003 and inflated since then on an annual basis will be revised as well. The regulatory treatment of operational expenses in the tariff after 2008 is unclear at this point.

United Kingdom. ***AES Kilroot in Northern Ireland is subject to the regime established by the Large Combustion Plants Directive (LCPD) and will therefore be required to*** comply ***with the increased restrictions on emissions imposed under that regime. It is also required to obtain a permit under the IPPC Directive to enable it to continue to operate. AES Kilroot will be implementing modifications to ensure that the plant complies with the requirements of the LCPD and the IPPC Directive.***

AES Kilroot is subject to regulation by the Northern Ireland Authority for Energy Regulation (NIAER). Under the terms of the generating license granted to AES Kilroot, the NIAER has the right to review and, subject to compliance with certain procedural steps and conditions, require the early termination of the long-term power purchase agreements under which AES Kilroot currently supplies electricity to Northern Ireland Electricity (NIE) until 2010.

On March 21, 2007, Order 2007 (Single Wholesale Market Northern Ireland) was enacted, which provides for the introduction and regulation of a single wholesale electricity market for Northern Ireland and the Republic of Ireland. The legislation grants powers to the Department of Enterprise, Trade and Investment or NIAER for a period of two years to modify existing arrangements within the electricity market in Northern Ireland, including the power to modify existing licenses and/or require the amendment or termination of existing agreements or arrangements, to allow for the creation of a single wholesale electricity market. AES Kilroot is assessing the potential impact of this new legislation.

Following receipt of a complaint from Friends of the Earth claiming that the existing long-term power purchase agreements with NIE in Northern Ireland are incompatible with EU law, the EC has requested certain information from the UK authorities related to these agreements, including information pertaining to the AES Kilroot power plant and power purchase agreement in order to enable the EC to assess the complaint. DETI submitted a response to the EC on January 12, 2007. It is not possible at this stage to predict the outcome of this inquiry.

Cameroon. The law governing the Cameroonian electricity sector was passed and promulgated in December 1998, which defines the new institutional organization of the electricity sector (Law no. 98/022 of 24 December 1998 governing the electricity sector). This law, and subsequent ministerial decrees and orders, govern the activities of the electricity sector, sets the rates and basis for the calculation, recovery and distribution of royalties due by operators in the electricity sector, and spells out required documents and charges for the processing of applications relating to concession, license, authorization and declaration in order to carry out generation, transmission, distribution, importation, exportation and sales of electricity.

The mission of the Electricity Sector Regulatory Board (ARSEL) is to regulate and ensure the proper functioning of the electricity sector, maintain its economic and financial balance and safeguard the interests of electricity operators and consumers. ARSEL has the legal status of a Public Administrative Establishment and is placed under the dual technical supervisory authority of the Ministries charged with electricity and finance.

The concession agreement of July 18, 2001 between the Republic of Cameroon and AES SONEL covers a twenty-year (20) period of which the first three years constituted a grace period to permit resolution of issues existing at the time of the privatization, and all penalties were waived. In 2004, AES SONEL and the Cameroonian government started renegotiating the concession contract. The issues included in this renegotiation process were: the quality of services requirements, the connection targets, the tariff formulation, the obligation of developing new generation capacity and the penalties regime. AES SONEL completed the renegotiation process and executed a new concession agreement on December 4, 2006.

Asia

China. In 2002, the State Council of the Chinese government promulgated the National Power Industry Framework Reform Plan (the Reform Plan). The Reform Plan separates generation and transmission and introduces market-driven competition into China s electric power industry whereby generators will be required to compete in the market for their output, with a system of competitive bidding for on-grid tariffs.

As a result of the Reform Plan, a new industry regulator, China s National Electricity Regulatory Commission (China s NERC) was established. China s NERC s responsibilities include: promulgating operating rules for the electric power industry; supervising the operation of the electric power industry and safeguarding fair competition; monitoring the quality and standard of production by electric power enterprises; and issuing and administrating electric power service licenses.

The ultimate adoption of the Reform Plan may result in market and regulatory changes.

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In April 2005, with a view to implementing the power industry reform, the National Development and Reform Commission released an interim regulation governing on-grid tariffs, along with two other regulations governing transmission and retail tariffs. All three came into effect on May 1, 2005 (Interim Regulations). Pursuant to the Interim Regulations, prior to adoption of a pooling system, the on-grid tariffs shall be appraised and ratified by the pricing authorities by reference to the economic life of power generation projects and determined in accordance with the principle of allowing independent power producers to cover reasonable costs and to obtain reasonable returns. However, the Interim Regulations further defined that the generation costs shall be the average costs in the industry, and reasonable returns shall be formulated on the basis of the interest rate of China s long-term treasury bond plus certain percentage points. The Interim Regulations will have far reaching consequences; but at this stage it is uncertain when the foregoing provision will be implemented or whether it will have a material adverse effect on the Company s businesses, except that it appears over the longer term, there will be increasing pressure on foreign-investors to renegotiate their PPAs.

China s central government also issued a policy allowing the on-grid tariffs to be pegged to the fuel price in the case of significant fluctuations in fuel price. Seventy percent (70%) of the increase in fuel costs may be passed to the tariff. Pursuant to this policy, the tariffs of our coal-fired facilities in China were increased in 2005 and 2006 to alleviate the escalation of fuel price.

India. India s power sector is regulated by the Central Electricity Regulatory Commission (CERC) at the national level and respective State Electricity Regulatory Commissions (SERCs) at the state level. CERC is responsible for regulating interstate generation, distribution and transmission, while intra-state generation, distribution and transmission are regulated by SERCs. The Government of India assists states in arranging financing for restructuring of state utilities for financial turnaround and facilitates investment in power sector.

In 2003, the Government of India enacted the Electricity Act 2003 (New Act) to establish a framework for a multi-seller-multi-buyer model for the electricity industry and introduced significant changes in India s electricity sector. In early 2004, the Government of India issued Guidelines for Determination of Tariff by Bidding Process for Procurement of Power by Distribution Licensees. In February 2005, the Government of India came out with the National Electricity Policy and in January 2006 published the National Tariff Policy (together Policy). CERC issued terms of conditions for tariff determination for inter-state generation and transmission and also notified open access for transmission.

The Policy establishes deadlines to implement different provisions of the New Act. However, the pace of actual implementation of the reform process is contingent on the respective state governments and SERCs as electricity is a concurrent subject in India s constitution.

It is not clear whether existing and concluded power purchase agreements are subject to re-opening by regulatory bodies under the New Act and the Policy. If re-opened, the review could have an adverse impact on OPGC, the Company s generation facility in India. The Electricity Appellate Tribunal is operational for dispute resolution as per New Act. A decision of Appellate Tribunal can be challenged only in the Supreme Court of India.

Alternative Energy

Under our plans for developing our Alternative Energy business, which includes wind generation, LNG re-gasification terminals, greenhouse gas emission credits and other initiatives, those businesses are, and would be, subject to complex laws and regulations and affected by changes in laws and regulations as well as changing governmental policies and regulatory actions. Many of AES Alternative Energy planned businesses may be significantly impacted by federal, state, and international incentives and other promotional policies relating to renewable and emerging energy technologies, carbon emissions and environmental issues. These incentives and policies are implemented and administered by a wide variety of governmental bodies that operate at the local, state, national and transnational levels. Notably, our current operating wind energy business could be adversely impacted by any significant changes or failure by the US Congress to extend the production tax credit incentive in section 45 of title 26 of the United States Code (currently set to expire on December 31, 2008). AES Alternative Energy business may also be significantly impacted by laws and regulations relating to the relationships between independent or competitive providers and utilities, competitive wholesalers, and competitive retailers in markets where it operates. Laws and regulations governing these relationships are implemented and administered by a wide variety of governmental bodies that operate at the state, national and transnational levels. These multiple and often interacting factors could have a negative impact on the business and results of operations of AES Alternative Energy business.

Environmental and Land Use Regulations

Overview. The Company is subject to various international, national, state and local environmental and land use laws and regulations. These laws and regulations primarily relate to discharges into the air and air quality, discharge of effluents into water and the use of water, waste disposal, remediation, noise pollution, contamination at current or former facilities or waste disposal sites, wetlands preservation and endangered species. Each of the countries in which the Company does business also has laws and regulations relating to the siting, construction, permitting, ownership, operation, modification, repair and decommissioning of, and power sales from, such assets. In addition, international projects funded by the World Bank are subject to World Bank environmental standards, which tend to be more stringent than local country standards. AES often has used advanced environmental technologies (such as circulating fluidized bed (CFB)) coal technologies or advanced gas turbines) in order to minimize environmental impacts.

Environmental laws and regulations affecting power 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 environmental laws and regulations. See Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Resources and Liquidity for more detail. If these regulations change, the Company may be required to make significant capital or other expenditures to comply. There can be no assurance that the Company would be able to recover from our customers these compliance costs such that our business, financial conditions or results of operations would not be materially and adversely 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 or interruptions to our operations. While the Company has at times been out of compliance with environmental laws and regulations, past non-compliance has not resulted in the revocation of material permits or licenses and has not had a material impact on our operations or results and we have expeditiously corrected the non-compliance as required.

Air Emissions. The U.S. Clean Air Act and various state laws and regulations regulate emissions of air pollutants, including sulfur dioxide (SO_2), nitrogen oxides (NOx) and particulate matter (PM). The Environmental Protection Agency s (EPA) rulemaking requiring adjustments to state implementation plans relating to NOx emissions (the NOx SIP Call) required coal-fired electric generating facilities in 21 U.S. states and the District of Columbia to either (i) reduce their NOx emissions to levels equal to allowances under the plan or (ii) purchase NOx emissions allowances from other operators to meet actual emissions levels by May 31, 2004. We have completed installing selective catalytic reduction (SCR) and other NOx control technologies at three coal-fired units of our subsidiary, Indianapolis Power and Light (IPL) in response to NOx SIP Call implementation and other proposed air emissions regulations that are discussed in more detail below.

In March 2005, the EPA finalized two rules that will affect many of our U.S. coal-fired power generating plants. The first rule, the Clean Air Interstate Rule (CAIR), was promulgated on March 10, 2005 and requires additional allowance surrender for SO_2 and NOx emissions from existing power plants located in 28 eastern states and the District of Columbia. CAIR will be implemented in two phases. The first phase will begin in 2009 and 2010 for NOx and SO_2, respectively. A second phase with additional allowance surrender obligations for both air pollutants emissions begins in 2015. The second rule, the Clean Air Mercury Rule (CAMR), was promulgated on March 15, 2005 and requires reductions of mercury emissions from coal-fired power plants in two phases. The first phase will begin in 2010 and will require nationwide reduction of coal-fired power plant mercury emissions from 48 to 38 tons per year. The second phase will begin in 2018 and will require nationwide reduction of mercury emissions from these sources from 38 tons per year to 15 tons per year. CAMR also establishes stringent mercury emission performance standards for new coal-fired power plants. To implement the required emission reductions for these two new rules, the states will establish emission allowance-based cap-and-trade programs.

Both the CAIR and CAMR have been challenged in federal court. No decisions have been rendered on the challenges. Also, a number of the states have indicated that they intend to impose more stringent emission limitations on power plants within their states rather than promulgate rules consistent with the CAIR and CAMR cap-and-trade programs. In response to CAIR, CAMR and potentially more stringent U.S. state initiatives on SO_2 and NOx emissions, AES completed a multi-pollutant control project at its Greenidge power plant in New York state and initiated construction of a similar project at its Westover power plant in New York state. In addition, a flue gas desulfurization scrubber upgrade project was completed at the IPL Petersburg power plant, and construction of an SCR system was initiated at our Deepwater petroleum coke-fired power plant near Houston, Texas.

While the exact impact and cost of these two new rules cannot be established until the states complete the process of assigning emission allowances to our affected facilities, there can be no assurance that the Company s business, financial conditions or results of operations would not be materially and adversely affected by these new rules.

The New York State Department of Environmental Conservation (NYSDEC) recently promulgated regulations requiring electric generators to reduce SO_2 emissions by 50% below current U.S. Clean Air Act standards. The SO_2 regulations began to be phased in beginning on January 1, 2005 with implementation to be completed by January 1, 2008. These regulations also establish stringent NOx reduction requirements year-round, rather than just during the summertime ozone season. As a result, in order to operate the Company s four electric generation facilities located in New York, installation of pollution control technology will likely be required.

In July 1999, the EPA published the Regional Haze Rule to reduce haze and protect visibility in designated federal areas. On June 15, 2005, 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 proposed amendment to the Regional Haze Rule would require states to consider the visibility impacts of the haze produced by an individual facility, in addition to other factors, when determining whether that facility must install potentially costly emissions controls. States are required to submit to the EPA their regional haze state implementation plans by December 2007. States that adopt the CAIR cap and trade program for SO_2 and NOx are allowed to apply CAIR controls as a substitute for BART controls.

Currently in the United States there are no federal mandatory greenhouse gas emission reduction programs (including carbon dioxide (CO_2)) affecting the Company s electricity power generation facilities. The U.S. Congress has debated a number of proposed greenhouse gas legislative initiatives, but to date there have been no new federal laws in this area. Nine states have entered into a memorandum of understanding under which the states would coordinate to establish rules that require the reduction in CO_2 emissions from power plant operations with those states. This initiative is called the Regional Greenhouse Gas Initiative (RGGI). On August 15, 2006, seven northeastern U.S. states issued a finalized model rule to implement RGGI. When it goes into effect, the RGGI initiative will impose a cap on baseline CO_2 emissions during the 2009 through 2014 period, and mandate a ten percent reduction in CO_2 emissions during the 2015 to 2019 period. 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 to promulgate regulations that will reduce CO_2 and other greenhouse gas emissions to 1990 levels by 2020. Although specific implementation measures for RGGI and A.B. 32 have yet to be finalized, these greenhouse gas-related initiatives may potentially affect AES electric power generation facilities in California, New York, Connecticut and New Jersey. At present, the Company cannot predict whether compliance with potential future U.S. national, regional and state greenhouse gas emission reduction programs will have a material impact on our operations or results.

In Europe the Company is, and will continue to be, required to reduce air emissions from our facilities to comply with applicable European Community (EC) Directives, including Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from large combustion plants (the LCPD), which sets emission limit values for NO_x, SO_2, and particulate matter for large-scale industrial combustion plants for all member states. Until June 2004, existing coal plants could opt-in or opt-out of the LCPD emissions standards. Those plants that opted out will be required to cease all operations by 2015 and may not operate for more than 20,000 hours after 2008. Those that opt-in, like the Company s AES Kilroot facility in the United Kingdom, must invest in abatement technology to achieve specific SO_2 reductions. Generally, AES s other coal plants in Europe have opted-in but will not require any additional abatement technology to comply with the LCPD.

In July 2003, the EC Directive 2003/87/EC on Greenhouse Gas Emission Allowance Trading was created, which requires member states to limit emissions of CO_2 from large industrial sources within their countries. To do so, member states are required to implement EC approved national allocation plans (NAPs). Under the NAPs, member states are responsible for allocating limited CO_2 allowances within their borders. Directive 2003/87/EC does not dictate how these allocations are to be made, and NAPs that have been submitted thus far have varied their allocation methodologies. For these and other reasons, there remain significant uncertainties regarding the application of the European Union Emissions Trading System which commenced operation in January 2005. Based on its current analyses, the Company expects that certain AES businesses will be under-allocated and others will be over-allocated. Although: i) we have a limited number of operating facilities that fall under EU ETS control, ii) a couple of these have very low baseline emissions because they are either biomass only or co-fire biomass, and iii) the risk and benefit at others are not the responsibility of AES as they are subject to change of law provisions that transfer responsibility for environmental compliance with these regulations to our offtakers, the fact remains that the Company cannot predict whether compliance with the respective NAPs will have a material impact on our operations or results.

On February 16, 2005, the Kyoto Protocol to the United Nations Framework Convention on Climate Change (the Kyoto Protocol) became effective. The Kyoto Protocol requires countries that have ratified it to substantially reduce their greenhouse gas emissions including CO_2. AES presently has generation operations in five countries that have ratified the Kyoto Protocol. Over the course of the next several years, as decisions surrounding implementation of the Kyoto Protocol become more detailed, the Company will have a better understanding of the impact of the Kyoto Protocol on itself. In the interim we announced on September 21, 2006, that we will produce 10 million tons of CO_2 equivalent greenhouse gas offsets by 2012 in Asia, Africa, Europe and Latin America by developing and operating projects under the Clean Development Mechanism of the Kyoto Protocol. At present the Company cannot predict whether compliance with the Kyoto Protocol will have a material impact on its operations or results.

Water Discharges. The Company s facilities are subject to a variety of rules governing water discharges. In particular the Company is evaluating the impact of the U.S. Clean Water Act Section 316(b) rule regarding existing power plant cooling water intake structures issued by the U.S. EPA in 2004 (69 Fed. Reg. 41579, July 9, 2004). The rule as currently issued will affect 12 U.S. AES power plants, the rule s requirements will be implemented via each plant s National Pollutant Discharge Elimination System (NPDES) water quality permit renewal process, and these permits are usually processed by state water quality agencies. To protect fish and other aquatic organisms, the 2004 rule requires existing steam electric generating facilities to utilize the best technology available for cooling water intake structures. To comply it must first prepare a Comprehensive Demonstration Study to assess each facility s effect on the local aquatic environment. Since each facility s design, location, existing control equipment and results of impact assessments must be taken into consideration, costs will likely vary. The timing of capital expenditures to achieve compliance with this rule will vary from site to site and may begin as early as 2008 for some of our U.S. plants. However, as a result of a recent United States Court of Appeals for the Second Circuit decision (Docket Nos. 04-6692 to 04-6699) remanding major parts of the 2004 rule back to U.S. EPA, we expect further delays in implementing the rule at many of our affected facilities. At present, the Company cannot predict whether compliance with the 316(b) rule will have a material impact on our operations or results.

Waste Management. In the course of operations, the Company s facilities generate solid and liquid waste materials requiring eventual disposal. With the exception of coal combustion products (CCP), its wastes are not usually physically disposed of on our property, but are shipped off site for final disposal, treatment or recycling. CCP, 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 CCP, 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 its solid and liquid wastes are disposed of in accordance with applicable national, regional, state and local regulations.

ITEM 1A. RISK FACTORS

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

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

Our disclosure controls and procedures and internal control over financial reporting were determined not to be effective as of December 31, 2006, December 31, 2005 and December 31, 2004, as evidenced by the material weaknesses that existed in our internal controls. Our disclosure controls and procedures and internal control over financial reporting may not be effective in future periods, as a result of existing or newly identified material weaknesses in internal controls.

Our management reported material weaknesses in our internal control over financial reporting at the end of 2006, 2005 and 2004. A material weakness is a deficiency, or a combination of deficiencies, that adversely affects a company s ability to initiate, authorize, record, process, or report external financial data reliably in accordance with generally accepted accounting principles such that there is more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. Our management concluded that as of December 31, 2006, December 31, 2005 and December 31, 2004, we did not maintain effective internal control over financial reporting and concluded that our disclosure controls and procedures were not effective to provide reasonable assurance that financial information we are required to disclose in our reports under the Securities Exchange Act of 1934 was recorded, processed, summarized and reported accurately. For a discussion of the material weaknesses reported by AES s management as of December 31, 2006 and December 31, 2005 see Item 9A of this 2006 Annual Report on Form 10-K.

During the remediation efforts to correct the material weakness that was identified at the end of 2004, errors were discovered in our financial statements which resulted from such material weakness, as well as errors resulting from newly identified material weaknesses. These errors required us to restate our financial statements that were previously filed in our Annual Report on Form 10-K for the year ended December 31, 2004 and our quarterly report on Form 10-Q for the quarter ended March 31, 2005. During the 2005 year-end closing process and the first quarter of 2006, additional errors were identified relating to the existing material weakness and newly identified material weaknesses that required us to restate prior period financial statements on January 19, 2006 and April 4, 2006. In addition, during the 2006 year-end closing process further errors were identified relating to existing material weaknesses as well as related to newly identified material weaknesses that required us to restate our previously filed 10-K s and 10-Q s for a fourth time. To address these material weaknesses in our internal control over financial reporting, each time we prepared our annual and quarterly reports we performed additional analysis and other post-closing procedures in order to prepare our consolidated financial statements in accordance with generally accepted accounting principles. These additional procedures are costly, time consuming and require us to dedicate a significant amount of our resources, including the time and attention of our senior management, toward the correction of these problems.

Although we reported remediation of certain material weaknesses as of December 31, 2006 and continue to execute plans to remediate the remaining material weaknesses in 2007, there can be no assurance as to when the remediation plans will be fully implemented, nor can there be any assurance that additional material weaknesses will not be identified in the future. Due to our decentralized structure and our disparate accounting systems, we have additional work remaining to remediate our material weaknesses in internal control over financial reporting. Until our remediation efforts are completed, we will continue to be at an increased risk that our financial statements could contain errors that will be undetected, and we will continue to incur significant expense and management burdens associated with the additional procedures required to prepare our consolidated financial statements.

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

Our identification of material weaknesses in internal control over financial reporting caused us to miss deadlines for certain SEC filings and if further filing delays occur, they could result in negative attention and/or legal consequences for the Company.

Our identification of the material weaknesses in internal control over financial reporting caused us to delay the filing of certain quarterly and annual reports with the SEC to dates that went beyond the deadline prescribed by the SEC s rules to file such reports.

We did not timely file with the SEC our quarterly and annual reports for the year ended December 31, 2005; our annual report for the year ended December 31, 2006; and our quarterly report for the quarter ended March 31, 2007. Under SEC rules, failure to timely file these reports prohibits us from offering and selling our securities pursuant to our shelf registration statement on Form S-3, which has impaired and will continue to impair our ability to access the capital markets through the public sale of registered securities in a timely manner. We will regain our S-3 eligibility on June 1, 2008 if we timely file all required reports until that date.

The failure to file our 2005 and 2006 annual reports with the SEC in a timely fashion also resulted in covenant defaults under our Senior Secured Credit Facility and the indenture governing certain of our outstanding debt securities. Such defaults required us to obtain a waiver from the lender under the Senior Secured Credit Facility, while the default under the indentures was cured upon the filing of the reports within the permitted grace period.

Until our remediation efforts are completed, there will continue to be an increased risk that we will be unable to timely file future periodic reports with the SEC and that a related default under our senior secured credit facilities and indentures could occur. In addition, the material weaknesses in internal control, the restatements, and the delay in the filing of our quarterly reports and any similar problems in the future could have other adverse effects on our business, including, but not limited to:

- impairing our ability to access the capital markets, including, but not limited to the inability to offer and sell securities pursuant to a shelf registration statement on Form S-3;
- litigation or an expansion of the SEC s informal inquiry into our restatements or the commencement of formal proceedings by the SEC or other regulatory authorities, which could require us to incur significant legal expenses and other costs or to pay damages, fines or other penalties;
- additional covenant defaults, and potential events of default, under our senior secured credit facilities and the indentures governing our outstanding debt securities, resulting from our failure to timely file our financial statements;
- negative publicity;
- ratings downgrades; or
- the loss or impairment of investor confidence in the Company.

Risks Related to our High Level of Indebtedness

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

As of December 31, 2006, we had approximately $16.3 billion of outstanding indebtedness on a consolidated basis. All outstanding borrowings under The AES Corporation s Senior Secured Credit Facility, our Second Priority Senior Secured Notes and certain other indebtedness are secured by certain of our assets, including the pledge of capital stock of many of The AES Corporation s directly-held subsidiaries. Most of the debt of The AES Corporation s subsidiaries is secured by substantially all of the assets of those subsidiaries. Since we have such a high level of debt, a substantial portion of cash flow from operations must be used to make payment on this debt. Furthermore, since a significant percentage of our assets are used to secure this debt, this reduces the amount of collateral that is available for future secured debt or credit support and reduces our flexibility in dealing with these secured assets. This high level of indebtedness and related security could have other important consequences to us and our investors, including:

- making it more difficult to satisfy debt service and other obligations;
- increasing the likelihood of a downgrade of our debt, which can cause future debt payments to increase and consume an even greater portion of cash flow;
- increasing our vulnerability to general adverse economic and industry conditions;
- reducing the availability of cash flow to fund other corporate purposes and grow our business;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry;

- placing us at a competitive disadvantage to our competitors that are not as highly leveraged; and

- limiting, along with the financial and other restrictive covenants relating to such indebtedness, among other things, our ability to borrow additional funds as needed or take advantage of business opportunities as they arise, pay cash dividends or repurchase common stock.

The agreements governing our indebtedness, including the indebtedness of our subsidiaries, limit but do not prohibit the incurrence of additional indebtedness. To the extent we become more leveraged, the risks described above would increase. Further, our actual cash requirements in the future may be greater than expected. Accordingly, our cash flow from operations may not be sufficient to repay at maturity all of the outstanding debt as it becomes due and, in that event, we may not be able to borrow money, sell assets or otherwise raise funds on acceptable terms or at all to refinance our debt as it becomes due.

The AES Corporation is a holding company and its ability to make payments on its outstanding indebtedness, including its public debt securities, is dependent upon the receipt of funds from its subsidiaries by way of dividends, fees, interest, loans or otherwise.

The AES Corporation is a holding company with no material assets, other than the stock of its subsidiaries. All of The AES Corporation s revenue is generated through its subsidiaries. Accordingly, almost all of The AES Corporation s cash flow is generated by the operating activities of its subsidiaries. Therefore, The AES Corporation s ability to make payments on its indebtedness and to fund its other obligations is dependent not only on the ability of its subsidiaries to generate cash, but also on the ability of the subsidiaries to distribute cash to it in the form of dividends, fees, interest, loans or otherwise.

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

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

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

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

As of December 31, 2006, we had approximately $16.3 billion of outstanding indebtedness on a consolidated basis, of which approximately $4.8 billion was recourse debt of The AES Corporation and approximately $11.5 billion was non-recourse debt. In addition, at December 31, 2006, The AES Corporation had provided:

- financial and performance related guarantees or other credit support commitments to or for the benefit of its subsidiaries, which were limited by the terms of the agreements, to an aggregate of approximately $533 million; and

- $461 million in letters of credit outstanding and $1 million in surety bonds outstanding, which operate to guarantee performance relating to certain project construction and development activities and subsidiary operations.

The AES Corporation is also obligated under other commitments, which are limited to amounts, or percentages of amounts, received by The AES Corporation as distributions from its project subsidiaries. In addition, The AES Corporation has commitments to fund its equity in projects currently under development or in construction.

Some of our subsidiaries are currently in default with respect to all or a portion of their outstanding indebtedness. The total debt classified as current in our consolidated balance sheets related to such defaults was $245 million at December 31, 2006. While the lenders under our non-recourse project financings generally do not have direct recourse to The AES Corporation (other than to the extent of any credit support given by The AES Corporation), defaults thereunder can still have important consequences for The AES Corporation, including, without limitation:

- reducing The AES Corporation s receipt of subsidiary dividends, fees, interest, loan and other sources of cash since the project subsidiary will typically be prohibited from distributing cash to The AES Corporation during the pendancy of any default;

- triggering The AES Corporation s obligation to make payments under any financial guarantee, letter of credit or other credit support which The AES Corporation has provided to or on behalf of such subsidiary;

- causing The AES Corporation to record a loss in the event the lender forecloses on the assets;

- triggering defaults in The AES Corporation s outstanding debt and trust preferred instruments. For example, The AES Corporation s Senior Secured Credit Facility and outstanding senior notes include events of default for certain bankruptcy related events involving material subsidiaries. In addition, The AES Corporation s Senior Secured Credit Facility includes certain events of default relating to accelerations of outstanding debt of material subsidiaries; or

- the loss or impairment of investor confidence in the Company.

None of the projects that are currently in default are owned by subsidiaries that meet the applicable definition of materiality in The AES Corporation s Senior Secured Credit Facility in order for such defaults to trigger an event of default or permit acceleration under such indebtedness. However, as a result of future write down of assets, dispositions and other matters that affect our financial position and results of operations, it is possible that one or more of these subsidiaries could fall within the definition of a material subsidiary and thereby upon an acceleration of such subsidiary s debt, trigger an event of default and possible acceleration of the indebtedness under The AES Corporation s Senior Secured Credit Facility.

Risks Associated with our Ability to Raise Needed Capital

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

The AES Corporation requires cash primarily to fund:

- principal repayments of debt;
- interest and preferred dividends;
- acquisitions;
- construction and other project commitments;
- other equity commitments, including business development investments;
- taxes; and
- parent company overhead costs.

The AES Corporation s principal sources of liquidity are:

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

For a more detailed discussion of The AES Corporation s cash requirements and sources of liquidity, please see *Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Resources and Liquidity* in this 2006 Annual Report on Form 10-K.

While we believe that these sources will be adequate to meet our obligations at the parent company level for the foreseeable future, this belief is based on a number of material assumptions, including, without limitation, assumptions about our ability to access the capital or commercial lending markets, the operating and financial performance of our subsidiaries, exchange rates and the ability of our subsidiaries to pay dividends. Any number of assumptions could prove to be incorrect and therefore there can be no assurance that these sources will be available when needed or that our actual cash requirements will not be greater than expected. In addition, our cash flow may not be sufficient to repay at maturity all of the principal outstanding under our Senior Secured Credit Facility and our debt securities and may have to refinance such obligations. There can be no assurance that we will be successful in obtaining such refinancing and any of these events could have a material effect on us.

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

Our ability to arrange for financing on either a recourse or non-recourse basis and the costs of such capital are dependent on numerous factors, some of which are beyond our control, including:

- general economic and capital market conditions;
- the availability of bank credit;
- investor confidence;

- the financial condition, performance and prospects of The AES Corporation in general and/or that of any subsidiary requiring the financing; and

- changes in tax and securities laws which are conducive to raising capital.

Should future access to capital not be available, we may have to sell assets or decide not to build new plants or acquire existing facilities, either of which would affect our future growth.

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

From time to time, we rely on access to capital markets as a source of liquidity for capital requirements not satisfied by operating cash flows. If any of the credit ratings of The AES Corporation or its subsidiaries were to be downgraded, our ability to raise capital on favorable terms could be impaired and our borrowing costs would increase.

Furthermore, depending on The AES Corporation s credit ratings and the trading prices of its equity and debt securities, counter parties may no longer be as willing to accept general unsecured commitments by The AES Corporation to provide credit support. Accordingly, with respect to both new and existing commitments, The AES Corporation may be required to provide some other form of assurance, such as a letter of credit, to backstop or replace any credit support by The AES Corporation. There can be no assurance that such counter parties will accept such guarantees in the future. In addition, to the extent The AES Corporation is required and able to provide letters of credit or other collateral to such counterparties; it will limit the amount of credit available to The AES Corporation to meet its other liquidity needs.

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

Part of our strategy is to grow our business by developing Generation and Utility businesses in less developed economies where the return on our investment may be greater than projects in more developed economies. Commercial lending institutions sometimes refuse to provide non-recourse project financing in certain less developed economies, and in these situations we have sought and will continue to seek direct or indirect (through credit support or guarantees) project financing from a limited number of multilateral or bilateral international financial institutions or agencies. As a precondition to making such project financing available, the lending institutions may also require governmental guarantees of certain project and sovereign related risks. There can be no assurance, however, that project financing from the international financial agencies or that governmental guarantees will be available when needed, and if they are not, we may have to abandon the project or invest more of our own funds which may not be in line with our investment objectives and would leave less funds for other projects.

External Risks Associated with Revenue and Earnings Volatility

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

Our exposure to currency exchange rate fluctuations results primarily from the translation exposure associated with the preparation of our consolidated financial statements, as well as from transaction exposure associated with transactions in currencies other than an entity s functional currency. While our consolidated financial statements are reported in U.S. dollars, the financial statements of many of our subsidiaries outside the United States are prepared using the local currency as the functional currency and translated into U.S. dollars by applying appropriate exchange rates. As a result, fluctuations in the exchange rate of the U.S. dollar relative to the local currencies where our subsidiaries outside the United States report could cause significant fluctuations in our results. In addition, while our expenses with respect to foreign operations are generally denominated in the same currency as corresponding sales, we have transaction exposure to the extent receipts and expenditures are not offsetting in the subsidiary s functional currency. We also experience foreign transaction exposure to the extent monetary assets and liabilities, including debt, are in a different currency than the subsidiary s functional currency. Moreover, the costs of doing business abroad may increase as a result of adverse exchange rate fluctuations. Our financial position and results of operations have been significantly affected by fluctuations in the value of a number of currencies, primarily the Brazilian real, Venezuelan bolivar and Argentine peso. As our Brazilian and Argentine businesses primarily identify their local currency as its functional currency, devaluation of these currencies has resulted in deferred translation losses (foreign currency translation adjustments recognized in accumulated other comprehensive loss) based on positive net asset positions. Devaluation has also resulted in foreign currency transaction losses primarily associated with U.S. dollar debt at these businesses. As our Venezuelan business identifies the U.S. dollar as its functional currency, no deferred translation gains or losses are recognized. However, devaluation of the Venezuelan bolivar has resulted in foreign currency transaction gains associated with U.S. dollar at this subsidiary. In addition, because it is difficult to estimate the overall impact of foreign exchange fluctuations related to translation exposure on our results of operations, we do not separately quantify the impact on earnings.

Our businesses may incur substantial costs and liabilities and be exposed to price volatility as a result of risks associated with the wholesale electricity markets, which could have a material adverse effect on our financial performance.

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

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

- plant availability;
- competition;
- demand for energy commodities;
- electricity usage;
- seasonality;
- interest rate and foreign exchange rate fluctuation;
- availability and price of emission credits;
- input prices;
- weather;
- illiquid markets;
- transmission or transportation constraints or inefficiencies;
- availability of competitively priced alternative energy sources;
- available supplies of natural gas, crude oil and refined products, and coal;
- generating unit performance;
- natural disasters, terrorism, wars, embargoes and other catastrophic events;
- energy, market and environmental regulation, legislation and policies;

- geopolitical concerns affecting global supply of oil and natural gas; and
- general economic conditions in areas where we operate which impact energy consumption.

In addition, our business depends upon transmission facilities owned and operated by others. If transmission is disrupted or capacity is inadequate or unavailable, our ability to sell and deliver power may be limited. Several of our Alternative Energy initiatives may, if we are successful in developing them further, operate without long-term sales or fuel supply agreements, and, as a result, may experience significant volatility in their results of operations.

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

We routinely enter into contracts to hedge a portion of our purchase and sale commitments for electricity, fuel requirements and other commodities to lower our financial exposure related to commodity price fluctuations. As part of this strategy, we routinely utilize fixed-price forward physical purchase and sales contracts, futures, financial swaps, and option contracts traded in the over-the-counter markets or on exchanges. However, we may not cover the entire exposure of our assets or positions to market price volatility, and the coverage will vary over time. Furthermore, the risk management procedures we have in place may not always be followed or may not work as planned. In particular, if prices of commodities significantly deviate from historical prices or if the price volatility or distribution of these changes deviates from historical norms, our risk management system may not protect us from significant losses. As a result fluctuating commodity prices may negatively impact our financial results to the extent we have unhedged or inadequately hedged positions. In addition, certain types of economic hedging activities may not qualify for hedge accounting under GAAP, resulting in increased volatility in our net income.

Certain of our businesses are sensitive to variations in weather.

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

Risks Associated with our Operations

We do a significant amount of business outside the United States which presents significant risks.

During 2006, approximately 79% of our revenue was generated outside the United States and a significant portion of our international operations is conducted in developing countries. Part of our growth strategy is to expand our business in developing countries because the growth rates and the opportunity to implement operating improvements and achieve higher operating margins may be greater than those typically achievable in more developed countries. International operations, particularly the operation, financing and development of projects in developing countries, entail significant risks and uncertainties, including, without limitation:

- economic, social and political instability in any particular country or region;
- adverse changes in currency exchange rates;
- government restrictions on converting currencies or repatriating funds;
- unexpected changes in foreign laws and regulations or in trade, monetary or fiscal policies;
- high inflation and monetary fluctuations;

- restrictions on imports of coal, oil, gas or other raw materials required by our generation businesses to operate;
- threatened or consummated expropriation or nationalization of our assets by foreign governments;
- difficulties in hiring, training and retaining qualified personnel, particularly finance and accounting personnel with U.S. GAAP expertise;
- unwillingness of governments, government agencies or similar organizations to honor their contracts;
- inability to obtain access to fair and equitable political, regulatory, administrative and legal systems;
- adverse changes in government tax policy;
- difficulties in enforcing our contractual rights or enforcing judgments or obtaining a just result in local jurisdictions; and
- potentially adverse tax consequences of operating in multiple jurisdictions.

Any of these factors, by itself or in combination with others, could materially and adversely affect our business, results of operations and financial condition. For example, we recently sold our stake in EDC to PDVSA, a state owned company in Venezuela after Venezuelan President Hugo Chavez threatened to expropriate the electricity business in Venezuela. We expect to recognize an impairment charge of approximately $600 to $650 million. In addition, our Latin American operations experience volatility in revenues and earnings which have caused and are expected to cause significant volatility in our results of operations and cash flows. The volatility is caused by regulatory and economic difficulties, political instability and currency devaluations being experienced in many of these countries. This volatility reduces the predictability and enhances the uncertainty associated with cash flows from these businesses.

The operation of power generation and distribution facilities involves significant risks that could adversely affect our financial results.

The operation of power generation and distribution facilities involves many risks, including:

- equipment failure causing unplanned outages;
- failure of transmission systems;
- the dependence on a specified fuel source, including the transportation of fuel;
- catastrophic event such as fires, explosions, floods, earthquakes, hurricanes and similar occurrences; and
- environmental compliance.

Any of these risks could have an adverse effect on our generation and distribution facilities. In addition, a portion of our generation facilities were constructed many years ago. Older generating equipment may require significant capital expenditures to keep it operating at peak efficiency. This equipment is also likely to require periodic upgrading and improvement. Breakdown or failure of one of our operating facilities may prevent the facility from performing under applicable power sales agreements which, in certain situations, could result in termination of the agreement or incurring a liability for liquidated damages.

As a result of the above risks and other potential hazards associated with the power generation and distribution industries, we may from time to time become exposed to significant liabilities for which we may not have adequate insurance coverage. Power generation involves hazardous activities, including acquiring, transporting and unloading fuel, operating large pieces of rotating equipment and delivering

electricity to transmission and distribution systems. In addition to natural risks, such as earthquake, flood, lightning, hurricane and wind, hazards, such as fire, explosion, collapse and machinery failure, are inherent risks in our operations which may occur as a result of inadequate internal processes, technological flaws, human error or certain external events. The control and management of these risks are based on adequate development and training of personnel and on the existence of operational procedures, preventative maintenance plans and specific programs supported by quality control systems which minimize the possibility of the occurrence and impact of these risks.

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

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

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

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

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

Much of our generation business is dependent on one or a limited number of customers and a limited number of fuel suppliers.

Many of our generation plants conduct business under long-term contracts. In these instances we rely on power sales contracts with one or a limited number of customers for the majority of, and in some case all of, the relevant plant s output and revenues over the term of the power sales contract. The remaining terms of the power sales contracts range from 1 to 25 years. In many cases, we also limit our exposure to fluctuations in fuel prices by entering into long-term contracts for fuel with a limited number of suppliers. In these instances, the cash flows and results of operations are dependent on the continued ability of customers and suppliers to meet their obligations under the relevant power sales contract or fuel supply contract, respectively. Some of our long-term power sales agreements are for prices above current spot market prices. The loss of significant power sales contracts or fuel supply contracts, or the failure by any of the parties to such contracts to fulfill our obligations thereunder, could have a material adverse impact on our business, results of operations and financial condition.

We have sought to reduce this counter-party credit risk under these contracts in part by entering into power sales contracts with utilities or other customers of strong credit quality and by obtaining guarantees from the sovereign government of the customer s obligations. However, many of our customers do not have, or have failed to maintain, an investment grade credit rating, and our Generation business can not always obtain government guarantees and if they do, the government does not always have an investment grade credit rating. We have also sought to reduce our credit risk by locating our plants in different geographic areas in order to mitigate the effects of regional economic downturns. However, there can be no assurance that our efforts to mitigate this risk will be successful.

Competition is increasing and could adversely affect us.

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

Our business and results of operations could be adversely affected by changes in our operating performance or cost structure.

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

- changes in the availability of our generation facilities or distribution systems due to increases in scheduled and unscheduled plant outages, equipment failure, labor disputes, disruptions in fuel supply, inability to comply with regulatory or permit requirements or catastrophic events such as fires, floods, storms, hurricanes, earthquakes, explosions, terrorist acts or other similar occurrences; and

- changes in our operating cost structure including, but not limited to, increases in costs relating to: gas, coal, oil and other fuel; fuel transportation; purchased electricity; operations, maintenance and repair; environmental compliance, including the cost of purchasing emissions offsets and capital expenditures to install environmental emission equipment; transmission access; and insurance.

Any of the above risks could adversely affect our business and results of operations, and our ability to meet publicly announced projections or analysts expectations.

Our business is subject to substantial development uncertainties.

Certain of our subsidiaries and affiliates are in various stages of developing and constructing greenfield power plants, some but not all of which have signed long-term contracts or made similar arrangements for the sale of electricity. Successful completion depends upon overcoming substantial risks, including, but not limited to, risks relating to failures of siting, financing, construction, permitting, governmental approvals or the potential for termination of the power sales contract as a result of a failure to meet certain milestones. We believe that capitalized costs for projects under development are recoverable; however, there can be no assurance that any individual project will be completed and reach commercial operation. If these development efforts are not successful, we may abandon a project under development and write off the costs incurred in connection with such project. At the time of abandonment, we would expense all capitalized development costs incurred in connection therewith and could incur additional losses associated with any related contingent liabilities.

Our acquisitions may not perform as expected.

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

- we will be successful in transitioning them to private ownership;
- such businesses will perform as expected;
- we will not incur unforeseen obligations or liabilities;
- such business will generate sufficient cash flow to support the indebtedness incurred to acquire them or the capital expenditures needed to develop them; or
- the rate of return from such businesses will justify our decision to invest our capital to acquire them.

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

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

In some joint venture agreements where we do have majority control of the voting securities, we have entered into shareholder agreements granting protective minority rights to the other shareholders. In Brasiliana, for example, where we have a controlling equity position, BNDES (or its affiliates) own more than 49 percent of the voting equity. If BNDES decides to sell all of its shares, it has drag along rights with respect to our shares, which means that, if BNDES finds a third party buyer that wants to purchase its shares and our shares, BNDES has the right to cause us to sell our shares in Brasiliana to this buyer. We do have certain protections against this drag along right, such as the price must be at least the fair market value of the shares, and we have a right to acquire all of BNDES shares at this same price. Nevertheless, if we declined to purchase the BNDES shares, we could be forced to sell our interest.

Our Alternative Energy businesses face uncertain operational risks.

In many instances, our Alternative Energy businesses target industries that are created by, or significantly affected by technological innovation or new lines of business that are outside our core expertise of Generation and Utilities. Given the nascent nature of these industries, our ability to predict actual performance results may be hindered and we ultimately may not be successful in these areas.

Our Alternative Energy businesses may experience higher levels of volatility.

Our Alternative Energy efforts are, to some degree, focused on new or emerging markets. As these markets develop, long-term fixed priced contracts for the major cost and revenue components may be unavailable, which may result in these businesses having relatively high levels of volatility.

Risks associated with Governmental Regulation and Laws

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

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

- changes in the determination, definition or classification of costs to be included as reimbursable or pass-through costs;
- changes in the definition or determination of controllable or non-controllable costs;
- changes in the definition of events which may or may not qualify as changes in economic equilibrium;
- changes in the timing of tariff increases; or
- other changes in the regulatory determinations under the relevant concessions.

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

Our Generation business in the United States is subject to the provisions of various laws and regulations administered in whole or in part by the FERC, including the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Federal Power Act. The recently enacted Energy Policy Act of 2005 (EPAct 2005) made a number of changes to these and other laws that may affect our business. Actions by the FERC and by state utility commissions can have a material effect on our operations.

EPAct 2005 authorizes the FERC to remove the obligation of electric utilities under Section 210 of PURPA to enter into new contracts for the purchase or sale of electricity from or to Qualified Facilities (QFs) if certain market conditions are met. Pursuant to this authority, the FERC has proposed to remove the purchase/sale obligation for all utilities located within the control areas of the Midwest

Transmission System Operator, Inc., PJM Interconnection, L.L.C., ISO New England, Inc. and the New York Independent System Operator. In addition, the FERC is authorized under the new law to remove the purchase/sale obligations of individual utilities on a case-by-case basis. While the new law does not affect existing contracts, as a result of the changes to PURPA, our QFs may face a more difficult market environment when their current long-term contracts expire.

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

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

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

Finally, EPAct 2005 affects nearly every aspect of the energy business and energy regulation. We are still in the process of analyzing the new law s effects, and those effects could have a material adverse effect on our business.

Our businesses are subject to stringent environmental laws and regulations.

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

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

We and our affiliates are parties to material litigation and regulatory proceedings. Investors should review the descriptions of such matters contained in this annual report, as well as the other periodic reports that we file in the future with the SEC. There can be no assurances that the outcome of such matters will not have a material adverse effect on our consolidated financial position.

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

The Company has been cooperating with an informal inquiry by the SEC Staff concerning the Company s restatements and related matters, and has been providing information and documents to the SEC Staff on a voluntary basis. Because the Company is unable to predict the outcome of this inquiry, the SEC Staff may disagree with the manner in which the Company has accounted for and reported the financial impact of the adjustments to previously filed financial statements and there may be a risk that the inquiry by the SEC could lead to circumstances in which the Company may have to further restate previously filed financial statements, amend prior filings or take other actions not currently contemplated.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

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

ITEM 3. LEGAL PROCEEDINGS

In 1989, Centrais Elétricas Brasileiras S.A. (Eletrobrás) filed suit in the Fifth District Court in the State of Rio de Janeiro against Eletropaulo Eletricidade de São Paulo S.A. (EEDSP) relating to the methodology for calculating monetary adjustments under the parties financing agreement. In April 1999, the Fifth District Court found for Eletrobrás and, in September 2001, Eletrobrás initiated an execution suit in the Fifth District Court to collect approximately R$762 million (US$365 million) from Eletropaulo and a lesser amount from an unrelated company, Companhia de Transmissão de Energia Elétrica Paulista (CTEEP) (Eletropaulo and CTEEP were spun off of EEDSP pursuant to its privatization in 1998). Eletropaulo appealed and, in September 2003, the Appellate Court of the State of Rio de Janeiro ruled that Eletropaulo was not a proper party to the litigation because any alleged liability was transferred to CTEEP pursuant to the privatization. Subsequently, both Eletrobrás and CTEEP filed separate appeals to the Superior Court of Justice (SCJ). In June 2006, the SCJ reversed the Appellate Court s decision and remanded the case to the Fifth District Court for further proceedings, holding that Eletropaulo s liability, if any, should be determined by the Fifth District Court. Eletropaulo subsequently filed a motion for clarification of that decision, which was denied in February 2007. In April 2007 Eletropaulo filed appeals with the Special Court (the highest court within the SCJ) and the Supreme Court of Brazil. Eletrobras may resume the execution suit in the Fifth District Court at any time. If Eletrobras does so, Eletropaulo may be required to provide security in the amount of its alleged liability. Eletropaulo believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In September 1999, a state appellate court in Minas Gerais, Brazil, granted a temporary injunction suspending the effectiveness of a shareholders agreement between Southern Electric Brasil Participacoes, Ltda. (SEB) and the state of Minas Gerais concerning Companhia Energetica de Minas Gerais (CEMIG), an integrated utility in Minas Gerais. The Company s investment in CEMIG is through SEB. This shareholders agreement granted SEB certain rights and powers in respect of CEMIG (Special Rights). In March 2000, a lower state court in Minas Gerais held the shareholders agreement invalid where it purported to grant SEB the Special Rights and enjoined the exercise of the Special Rights. In August 2001, the state appellate court denied an appeal of the decision and extended the injunction. In October 2001, SEB filed appeals against the state appellate court s decision with the Federal Superior Court and the Supreme Court of Justice. The state appellate court denied access of these appeals to the higher courts, and in August 2002 SEB filed interlocutory appeals against such denial with the Federal Superior Court and the Supreme Court of Justice. In December 2004, the Federal Superior Court declined to hear SEB s appeal. However, the Supreme Court of Justice is considering whether to hear SEB s appeal. SEB intends to vigorously pursue a restoration of the value of its investment in CEMIG by all legal means; however, there can be no assurances that it will be successful in its efforts. Failure to prevail in this matter may limit SEB s influence on the daily operation of CEMIG.

In August 2000, the Federal Energy Regulatory Commission (FERC) announced an investigation into the organized California wholesale power markets in order to determine whether rates were just and reasonable. Further investigations involved alleged market manipulation. FERC requested documents from each of the AES Southland, LLC plants and AES Placerita, Inc. AES Southland and AES Placerita have cooperated fully with the FERC investigation. AES Southland was not subject to refund liability because it did not sell into the organized spot markets due to the nature of its tolling agreement. AES Placerita is currently subject to refund liability of $588,000 plus interest for spot sales to the California Power Exchange from October 2, 2000 to June 20, 2001 (Refund Period). In September 2004, the U.S. Court of Appeals for the Ninth Circuit issued an order addressing FERC s decision not to impose refunds for the alleged failure to file rates, including transaction-specific data, for sales during 2000 and 2001 (September 2004 Decision). Although it did not order refunds, the Ninth Circuit remanded the case to FERC for a refund proceeding to consider remedial options. The Ninth Circuit has temporarily stayed the remand to FERC until June 13, 2007, so that settlement discussions may take place. AES Placerita and other parties are also seeking review of the September 2004 Decision in the U.S. Supreme Court. In addition, in August 2006 in a separate case, the Ninth Circuit confirmed the Refund Period, expanded the transactions subject to refunds to include multi-day transactions, expanded the potential liability of sellers to include any pre-Refund Period tariff violations, and remanded the matter to FERC (August 2006 Decision). The Ninth Circuit has temporarily stayed its August 2006 Decision until June 13, 2007, to facilitate settlement discussions. The August 2006 Decision may allow FERC to reopen closed investigations and order relief. Placerita made sales during the periods at issue in the September 2004 and August 2006 Decisions. Both appeals may be subject to further court review, and further FERC proceedings on remand would be required to determine potential liability, if any. Prior to the August 2006 Decision, AES Placerita s potential liability could have approximated $23 million plus interest. However, given the September 2004 and August 2006 Decisions, it is unclear whether AES Placerita s potential liability is less than or exceeds that amount. AES Placerita believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In November 2000, the Company was named in a purported class action along with six other defendants, alleging unlawful manipulation of the California wholesale electricity market, allegedly resulting in inflated wholesale electricity prices throughout California. The alleged causes of action include violation of the Cartwright Act, the California Unfair Trade Practices Act and the California Consumers Legal Remedies Act. In December 2000, the case was removed from the San Diego County Superior Court to the U.S. District Court for the Southern District of California. On July 30, 2001, the Court remanded the case to San Diego Superior Court. The case was consolidated with five other lawsuits alleging similar claims against other defendants. In March 2002, the plaintiffs filed a new master complaint in the consolidated action, which reasserted the claims raised in the earlier action and names the Company, AES Redondo Beach, LLC, AES Alamitos, LLC, and AES Huntington Beach, LLC as defendants. In May 2002, the case was removed by certain cross-defendants from the San Diego County Superior Court to the U.S. District Court for the Southern District of California. The plaintiffs filed a motion to remand the case to state court, which was granted on December 13, 2002. Certain defendants appealed aspects of that decision to the U.S. Court of Appeals for the Ninth Circuit. In December 2004, a panel of the Ninth Circuit issued an opinion affirming in part and reversing in part the decision of the District Court, and remanding the case to state court. In July 2005, defendants filed a demurrer in state court seeking dismissal of the case in its entirety. In October 2005, the court sustained the demurrer and entered an order of dismissal. In December 2005, plaintiffs filed a notice of appeal with the California Court of Appeal. In February 2007, the Court of Appeal affirmed the trial Court s judgment of dismissal. Plaintiffs did not appeal the Court of Appeal s decision.

In August 2001, the Grid Corporation of Orissa, India (Gridco), filed a petition against the Central Electricity Supply Company of Orissa Ltd. (CESCO), an affiliate of the Company, with the Orissa Electricity Regulatory Commission (OERC), alleging that CESCO had defaulted on its obligations as an OERC-licensed distribution company, that CESCO management abandoned the management of CESCO, and asking for interim measures of protection, including the appointment of an administrator to manage CESCO. Gridco, a state-owned entity, is the sole wholesale energy provider to CESCO. Pursuant to the OERC s August 2001 order, the management of CESCO was replaced with a government administrator who was appointed by the OERC. The OERC later held that the Company and other CESCO shareholders were not necessary or proper parties to the OERC proceeding. In August 2004, the OERC issued a notice to CESCO, the Company and others giving the recipients of the notice until November 2004 to show cause why CESCO s distribution license should not be revoked. In response, CESCO submitted a business plan to the OERC. In February 2005, the OERC issued an order rejecting the proposed business plan. The order also stated that the CESCO distribution license would be revoked if an acceptable business plan for CESCO was not submitted to, and approved by, the OERC prior to March 31, 2005. In its April 2, 2005 order, the OERC revoked the CESCO distribution license. CESCO has filed an appeal against the April 2, 2005 OERC order and that appeal remains pending in the Indian courts. In addition, Gridco asserted that a comfort letter issued by the Company in connection with the Company s indirect investment in CESCO obligates the Company to provide additional financial support to cover all of CESCO s financial obligations to Gridco. In December 2001, Gridco served a notice to arbitrate pursuant to the Indian Arbitration and Conciliation Act of 1996 on the Company, AES Orissa Distribution Private Limited (AES ODPL), and Jyoti Structures (Jyoti) pursuant to the terms of the CESCO Shareholders Agreement between Gridco, the Company, AES ODPL, Jyoti and CESCO (the CESCO arbitration). In the arbitration, Gridco appears to seek approximately $188.5 million in damages plus undisclosed penalties and interest, but a detailed alleged damages analysis has yet to be filed by Gridco. The Company has counterclaimed against Gridco for damages. An arbitration hearing with respect to liability was conducted on August 9, 2005 in India. Final written arguments regarding liability were submitted by the parties to the arbitral tribunal in late October 2005. A decision on liability has not yet been issued. Moreover, a petition remains pending before the Indian Supreme Court concerning fees of the third neutral arbitrator and the venue of future hearings with respect to the CESCO arbitration. The

Company believes that it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In December 2001, a petition was filed by Gridco in the local India courts seeking an injunction to prohibit the Company and its subsidiaries from selling their shares in Orissa Power Generation Company Pvt. Ltd. (OPGC), an affiliate of the Company, pending the outcome of the above-mentioned CESCO arbitration. OPGC, located in Orissa, is a 420 MW coal-based electricity generation business from which Gridco is the sole off-taker of electricity. Gridco obtained a temporary injunction, but the District Court eventually dismissed Gridco s petition for an injunction in March 2002. Gridco appealed to the Orissa High Court, which in January 2005 allowed the appeal and granted the injunction. The Company has appealed the High Court s decision to the Supreme Court of India. In May 2005, the Supreme Court adjourned this matter until August 2005. In August 2005, the Supreme Court adjourned the matter again to await the award of the arbitral tribunal in the CESCO arbitration. The Company believes that it has meritorious claims and defenses and will assert them vigorously in these proceedings; however there can be no assurances that it will be successful in its efforts.

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

In April 2002, IPALCO Enterprises, Inc. (IPALCO), the pension committee for the Indianapolis Power & Light Company thrift plan (Pension Committee), and certain former officers and directors of IPALCO were named as defendants in a purported class action filed in the U.S. District Court for the Southern District of Indiana. In May 2002, an amended complaint was filed in the lawsuit. The amended complaint asserts that IPALCO and former members of the Pension Committee breached their fiduciary duties to the plaintiffs under the Employees Retirement Income Security Act by investing assets of the thrift plan in the common stock of IPALCO prior to the acquisition of IPALCO by the Company. In September 2003 the Court granted plaintiffs motion for class certification. In October 2003 the parties filed cross-motions for summary judgment on liability. In August 2005, the Court issued an order denying the summary judgment motions, but striking one defense asserted by defendants. A trial addressing only the allegations of breach of fiduciary duty began on February 21, 2006 and concluded on February 28, 2006. In March 2007, the Court issued a decision in favor of the defendants and dismissed the lawsuit with prejudice. In April 2007, plaintiffs appealed the Court s decision to the U.S. Court of Appeals for the Seventh Circuit as to the former officers and directors of IPALCO, but not as to IPALCO or the Pension Committee.

In March 2003, the office of the Federal Public Prosecutor for the State of Sao Paulo, Brazil (MPF) notified AES Eletropaulo that it had commenced an inquiry related to the Brazilian National Development Bank (BNDES) financings provided to AES Elpa and AES Transgás and the rationing loan provided to Eletropaulo, changes in the control of Eletropaulo, sales of assets by Eletropaulo and the quality of service provided by Eletropaulo to its customers, and requested various documents from Eletropaulo relating to these matters. In July 2004, the MPF filed a public civil lawsuit in federal court alleging that BNDES violated Law 8429/92 (the Administrative Misconduct Act) and BNDES s internal rules by: (1) approving the AES Elpa and AES Transgás loans; (2) extending the payment terms on the AES Elpa and AES Transgás loans; (3) authorizing the sale of Eletropaulo s preferred shares at a stock-market auction; (4) accepting Eletropaulo s preferred shares to secure the loan provided to Eletropaulo; and (5) allowing the restructurings of Light Serviços de Eletricidade S.A. (Light) and Eletropaulo. The MPF also named AES Elpa and AES Transgás as defendants in the lawsuit because they allegedly benefited from BNDES s alleged violations. In June 2005, AES Elpa and AES Transgás presented their preliminary answers to the charges. In May 2006, the federal court ruled that the MPF could pursue its claims based on the first, second, and fourth alleged violations noted above. The MPF subsequently filed an interlocutory appeal seeking to require the federal court to consider all five alleged violations. Also, in July 2006, AES Elpa and AES Transgás filed an interlocutory appeal seeking to enjoin the federal court from considering any of the alleged violations. The MPF s lawsuit before the federal court has been stayed pending those interlocutory appeals. AES Elpa and AES Transgás believe they have meritorious defenses to the allegations asserted against them and will defend themselves vigorously in these proceedings; however, there can be no assurances that they will be successful in their efforts.

In May 2003, there were press reports of allegations that Light colluded with Enron in April 1998 in connection with the auction of Eletropaulo. Enron and Light were among three potential bidders for Eletropaulo. At the time of the transaction in 1998, AES owned less than 15% of Light s stock and shared representation in Light s management and Board with three other shareholders. In June 2003, the Secretariat of Economic Law of the Ministry of Justice of Brazil (SDE) issued a notice of preliminary investigation seeking information from a number of entities, including AES Brasil Energia, with respect to the allegations in the press reports. As AES Brasil Energia was incorrectly cited in the original complaint, in August 2003, AES Elpa responded on behalf of AES-affiliated companies and denied knowledge of these allegations. SDE began a follow-up administrative proceeding as reported in a notice published in October 2003. In response to SDE s official letters requesting explanations on the accusations, AES Elpa filed its defense in January 2004. In April 2005, AES Elpa responded to an SDE request for additional information. In June 2005, SDE dismissed the case because the statute of limitations had expired and its investigation had found no evidence supporting the allegations. Subsequently, the case was sent to the Administrative Council for Economic Defense (CADE), the Brazilian antitrust authority, for final review of the decision. Furthermore, the São Paulo s State Public Attorney's Office and the Federal Public Attorney s Office issued separate opinions concluding that the case should be dismissed because the statute of limitations had expired. The São Paulo s State Public Attorney s Office further found that there was no evidence of any wrongdoing. These opinions were ratified by the relevant state and federal courts. In January 2007, CADE decided by unanimous vote of its Counselors to close the case.

AES Florestal, Ltd. (Florestal), had been operating a pole factory and had other assets, including a wooded area known as Horto Renner , in the State of Rio Grande do Sul, Brazil (collectively, Property). AES Florestal had been under the control of AES Sul since October 1997, when AES Sul was created pursuant to a privatization by the Government of the State of Rio Grande do Sul. After it came under the control of AES Sul, AES Florestal performed an environmental audit of the entire operational cycle at the pole factory. The audit discovered 200 barrels of solid creosote waste and other contaminants at the pole factory. The audit concluded that the prior operator of the pole factory, Companhia Estadual de Energia Elétrica (CEEE), had been using those contaminants to treat the poles that were manufactured at the factory. AES Sul and AES Florestal subsequently took the initiative of communicating with Brazilian authorities, as well as CEEE, about the adoption of containment and remediation measures. The Public Attorney s Office has initiated a civil inquiry (Civil Inquiry n. 24/05) to investigate potential civil liability and has requested that the police station of Triunfo institute a Police Investigation (IP number 1041/05) to investigate potential criminal liability regarding the contamination at the pole factory. The environmental agency (FEPAM) has also started a procedure (Procedure n. 088200567/05 9) to analyze the measures that shall be taken to contain and remediate the contamination. The measures that must be taken by AES

Sul and CEEE are still under discussion. Also, in March 2000, AES Sul filed suit against CEEE in the 2nd Court of Public Treasure of Porto Alegre seeking to register in AES Sul s name the Property that it acquired through the privatization but that remained registered in CEEE s name. During those proceedings, a court-appointed expert acknowledged that AES Sul had paid for the Property but opined that the Property could not be re-registered in AES Sul s name because CEEE did not have authority to transfer the Property through the privatization. Therefore, AES waived its claim to re-register the Property and asserted a claim to recover the amounts paid for the Property. That claim is pending. Moreover, in February 2001, CEEE and the State of Rio Grande do Sul brought suit in the 7th Court of Public Treasure of Porto Alegre against AES Sul, AES Florestal, and certain public agents that participated in the privatization. The plaintiffs alleged that the public agents unlawfully transferred assets and created debts during the privatization. In 2005, the control of AES Florestal was transferred from AES Sul to AES Guaíba II in accordance with Federal Law n. 10848/04. AES Florestal subsequently became a non-operative company. In November 2005, the Court ruled that the Property must be returned to CEEE. Subsequently, AES Sul and CEEE jointly possessed the Property for a time, but CEEE has had sole possession of Horto Renner since September 2006 and of the rest of the Property since April 2006.

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

In April 2004, BNDES filed a collection suit against SEB to obtain the payment of R$3.3 billion (US$1.6 billion) under the loan agreement between BNDES and SEB, the proceeds of which were used by SEB to acquire shares of CEMIG. In May 2004, the 15th Federal Circuit Court ordered the attachment of SEB's CEMIG shares, which were given as collateral for the loan, as well as dividends paid by CEMIG to SEB. At the time of the attachment, the shares were worth approximately R$762 million (US$247 million). In March 2007, the dividends were determined to be worth approximately R$423 million (US$ 210 million). SEB s defense was ruled groundless by the Circuit Court in December 2006. In January 2007, SEB filed an appeal to the relevant Federal Court of Appeals. BNDES may attempt to seize the attached CEMIG shares and withdraw the dividends at any time. SEB believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In July 2004, the Corporación Dominicana de Empresas Eléctricas Estatales (CDEEE) filed lawsuits against Itabo, an affiliate of the Company, in the First and Fifth Chambers of the Civil and Commercial Court of First Instance for the National District. CDEEE alleges in both lawsuits that Itabo spent more than was necessary to rehabilitate two generation units of an Itabo power plant, and, in the Fifth Chamber lawsuit, that those funds were paid to affiliates and subsidiaries of AES Gener and Coastal

Itabo, Ltd. (Coastal) without the required approval of Itabo s board of administration. AES Gener and Coastal were shareholders of Itabo during the rehabilitation, but Coastal later sold its interest in Itabo to an indirect subsidiary of the Company. In the First Chamber lawsuit, CDEEE seeks an accounting of Itabo s transactions relating to the rehabilitation. In November 2004, the First Chamber dismissed the case for lack of legal basis. On appeal, in October 2005 the Court of Appeals of Santo Domingo ruled in Itabo s favor, reasoning that it lacked jurisdiction over the dispute because the parties contracts mandated arbitration. The Supreme Court of Justice is considering CDEEE s appeal of the Court of Appeals decision. In the Fifth Chamber lawsuit, which also names Itabo s former president as a defendant, CDEEE seeks $15 million in damages and the seizure of Itabo s assets. In October 2005, the Fifth Chamber held that it lacked jurisdiction to adjudicate the dispute given the arbitration provisions in the parties contracts. The First Chamber of the Court of Appeal ratified that decision in September 2006. In a related proceeding, in May 2005, Itabo filed a lawsuit in the U.S. District Court for the Southern District of New York seeking to compel CDEEE to arbitrate its claims. The petition was denied in July 2005. Itabo s appeal of that decision to the U.S. Court of Appeal for the Second Circuit has been stayed since September 2006. Also, in February 2005, Itabo initiated arbitration against CDEEE and the Fondo Patrimonial de las Empresas Reformadas (FONPER) in the International Chamber of Commerce (ICC) seeking, among other relief, to enforce the arbitration provisions in the parties contracts. In March 2006, Itabo and FONPER settled their respective claims. In September 2006, the ICC determined that it lacked jurisdiction to decide the arbitration as to Itabo and CDEEE. Itabo believes it has meritorious claims and defenses and will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In October 2004, Raytheon Company (Raytheon) filed a lawsuit against AES Red Oak LLC (Red Oak) in the Supreme Court of the State of New York, County of New York. The complaint purports to allege claims for breach of contract, fraud, interference with contractual rights and equitable relief relating to the construction and/or performance of the Red Oak project, an 800 MW combined cycle power plant in Sayreville, New Jersey. The complaint seeks the return of approximately $30 million that was drawn by Red Oak under a letter of credit that was posted by Raytheon for the construction and/or performance of the Red Oak project. Raytheon also seeks $110 million in purported additional expenses allegedly incurred by Raytheon in connection with the guaranty and construction agreements entered with Red Oak. In December 2004, Red Oak answered the complaint and filed breach of contract and fraud counterclaims against Raytheon. The Court subsequently ordered Red Oak to pay Raytheon approximately $16.3 million plus interest, which sum allegedly represented the amount of the letter of credit draw that had yet to be utilized for performance/construction issues. The Court also dismissed Red Oak s fraud claims, which decision was upheld on appeal. The parties have stipulated that Red Oak may assert claims for performance/construction issues if it has incurred costs on such claims. In May 2005, Raytheon filed a related action against Red Oak in the Superior Court of Middlesex County, New Jersey, seeking to foreclose on a construction lien in the amount of approximately $31 million on property allegedly owned by Red Oak. Red Oak filed its answer and counterclaim in October 2005. Red Oak believes it has meritorious claims and defenses and will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In January 2005, the City of Redondo Beach (City) of California issued an assessment against Williams Power Co., Inc., (Williams) and AES Redondo Beach, LLC (AES Redondo), an indirect subsidiary of the Company, for approximately $71.7 million in allegedly overdue utility users tax (UUT), interest, and penalties relating to the natural gas used at AES Redondo s power plant from May 1998 through September 2004 to generate electricity. In September 2005, the City Tax Administrator held AES Redondo and Williams jointly and severally liable for approximately $56.7 million in UUT, interest, and penalties. In October 2005, AES Redondo and Williams filed respective appeals with the City Manager, who appointed a Hearing Officer to decide the appeal. In December 2006, the Hearing Officer overturned the City s assessment against AES Redondo (but not Williams). In December 2006, Williams filed a petition for writ of mandate with Los Angeles Superior Court concerning the Hearing Officer s decision. Williams later prepaid $56.7 million to the City in order to continue litigating its petition, pursuant to a court order, and filed an amended petition. In March 2007, the City filed a petition for writ of mandate with the Superior Court concerning the Hearing Officer s decision as to AES Redondo. In addition, in July 2005, AES Redondo filed a lawsuit in Superior Court seeking a refund of UUT paid since February 2005, and an order that the City cannot charge AES Redondo UUT going forward. Williams later filed a similar complaint that was related to AES Redondo s lawsuit. After authorizing limited discovery on disputed jurisdictional and other issues, including whether AES Redondo and Williams must prepay to the City any allegedly owed UUT prior to judicially challenging the merits of the UUT, the Court stayed the case in December 2006. Furthermore, since December 2005, the Tax Administrator has periodically issued UUT assessments against AES Redondo and Williams for allegedly overdue UUT on the gas used at the power plant since October 2004 (New UUT Assessments). AES Redondo has objected to those and any future UUT assessments. The Tax Administrator has stated that AES Redondo s objections are moot in light of his September 2005 decision. The Tax Administrator has not scheduled a hearing on the New UUT assessments, but has indicated that if there is one he will only address the amount of those assessments, not the merits of them. AES Redondo believes that it has meritorious claims and defenses, and it will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In February 2006, the local Kazakhstan tax commission imposed an environmental fine on Maikuben West mine, for alleged unauthorized disposal of overburden in the mine during 2003 and 2004. On November 23, 2006, Maikuben West paid a fine of approximately $2.8 million in connection with this matter.

In March 2006, the Government of the Dominican Republic and Secretariat of State of the Environment and Natural Resources of the Dominican Republic (collectively, Plaintiffs) filed a complaint in the U.S. District Court for the Eastern District of Virginia against The AES Corporation, AES Aggregate Services, Ltd., AES Atlantis, Inc., and AES Puerto Rico, LP (collectively, AES Defendants), and unrelated parties, Silver Spot Enterprises and Roger Charles Fina. In June 2006, the Plaintiffs filed a substantially similar amended complaint against the defendants, alleging that the defendants improperly disposed of coal ash waste in the Dominican Republic, and that the alleged waste was generated at AES Puerto Rico s power plant in Guayama, Puerto Rico. Based on these allegations, the amended complaint asserts seven claims against the defendants: violation of 18 U.S.C. §§ 1961 68, the Racketeer Influenced and Corrupt Organizations Act (RICO Act); conspiracy to violate section 1962(c) of the RICO Act; civil conspiracy to violate the Foreign Corrupt Practices Act (FCPA) and other unspecified laws concerning bribery and waste disposal; aiding and abetting the violation of the FCPA and other unspecified laws concerning bribery and waste disposal; violation of unspecified nuisance law; violation of unspecified product liability law; and violation of 28 U.S.C. § 1350, the Alien Tort Statute (which the Plaintiffs later voluntarily dismissed without prejudice). While the Plaintiffs did not quantify their alleged damages in their amended complaint, in their discovery responses they claimed to be seeking at least $28 million in alleged compensatory damages and $196 million in alleged punitive damages from the defendants. In February 2007 the Plaintiffs and the AES Defendants settled their dispute. The Court has entered a joint stipulation dismissing the Plaintiffs claims against the AES Defendants with prejudice.

AES Eastern Energy voluntarily disclosed to the New York State Department of Environmental Conservation (NYSDEC) and the U.S. Environmental Protection Agency (EPA) on November 27, 2002 that nitrogen oxide (NOx) exceedances appear to have occurred on October 30 and 31, and November 1 8 and 10 of 2002. The exceedances were discovered through an audit by plant personnel of the Plant s NOx Reasonably Available Control Technology (RACT) tracking system. Immediately upon the discovery of the exceedances, the selective catalytic reduction (SCR) at the Somerset plant was activated to reduce NOx emissions. AES Eastern Energy learned of a notice of violation (the NOV) issued by the

NYSDEC for the NOx RACT exceedances through a review of the November 2004 release of the EPA s Enforcement and Compliance History (ECHO) database. However, AES Eastern Energy has not yet seen the NOV from the NYSDEC. AES Eastern Energy is currently negotiating with NYSDEC concerning this matter. On November 13, 2006 AES Eastern Energy paid a fine of $263,200 and entered into a consent decree with NYSDEC, addressing these matters.

In June 2006, AES Ekibastuz was found to have breached a local tax law by failing to obtain a license for use of local water for the period of January 1, 2005 through October 3, 2005, in a timely manner. As a result, an additional permit fee was imposed, brining the total permit fee to approximately $135,000. The company has appealed this decision to the Supreme Court.

In October 2006, the Constitutional Chamber of the Venezuelan Supreme Court decided that it would review a lawsuit filed in 2000 by certain Venezuelan citizens alleging that the Company s acquisition of a controlling stake in C.A. La Electricidad de Caracas in 2000 was void because the acquisition had not been approved by the Venezuelan National Assembly. AES has been notified of the Supreme Court s decision to review the lawsuit. AES believes that it complied with all existing laws with respect to the acquisition and that there are meritorious defenses to the allegations in this lawsuit; however, there can be no assurance that it will prevail in this lawsuit.

In October 2006, CDEEE began making public statements that it intends to seek to compel the renegotiation and/or rescission of long-term power purchase agreements with certain power-generation companies in the Dominican Republic. Although the details concerning CDEEE s statements are unclear and no formal government action has been taken, AES owns certain interests in three power-generation companies in the country (AES Andres, Itabo, and Dominican Power Partners) that could be adversely impacted by any actions taken by or at the direction of CDEEE.

In February 2007, the Competition Committee of the Ministry of Industry and Trading of the Republic of Kazakhstan initiated administrative proceedings against two hydro plants under AES concession, Ust-Kamenogorsk HPP and Shulbinsk HPP (collectively, Hydros), for allegedly using Nurenergoservice LLP to increase power prices for customers in alleged violation of Kazakhstan s antimonopoly laws. The Competition Committee subsequently issued orders directing the Hydros to pay approximately 4.3 billion KZT (US$35 million) in damages and fines. In April 2007 the Hydros appealed those orders to the local courts. In addition, Nurenergoservice has been informed that it will be ordered by the Competition Committee to pay approximately 2 billion KZT (US$ 15 million) for alleged antimonopoly violations. In related proceedings, in March 2007 the local financial police initiated criminal proceedings against the General Director and the Finance Director of the Hydros. Those proceedings were later terminated pursuant to a settlement. The Hydros and Nurenergoservice believe they have meritorious defenses and will assert them vigorously; however, there can be no assurances that they will be successful in their efforts.

ITEM 4. SUBMISSION OF MATTERS TO VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of security holders during the fourth quarter of 2006.

PART II

ITEM 5. *MARKET FOR REGISTRANT S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS*

Recent Sales Of Unregistered Securities

None.

Market Information

Our common stock is currently traded on the New York Stock Exchange (NYSE) under the symbol AES. The closing price of our common stock as reported by NYSE on May15, 2007, was $22.90, per share. The Company did not repurchase any of its common stock in 2006 or 2005. The following tables set forth the high and low sale prices, as well as performance trends, for our common stock as reported by the NYSE for the periods indicated.

	2006		**2005**	
Price Range of Common Stock	**High**	**Low**	**High**	**Low**
First Quarter	$ 17.71	$ 16.20	$ 17.65	$ 12.84
Second Quarter	18.76	16.40	17.36	13.72
Third Quarter	21.24	18.25	16.67	14.67
Fourth Quarter	23.72	20.21	17.10	14.94

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Performance Graph

THE AES CORPORATION
PEER GROUP INDEX/STOCK PRICE PERFORMANCE

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

Source: Bloomberg

COMPARISON OF 3 YEAR CUMULATIVE TOTAL RETURNS
ASSUMES INITIAL INVESTMENT OF $100

Source: Bloomberg

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

The 5 year total return chart assumes $100 invested on December 31, 2001 in AES Common Stock, the S&P 500 Index and the S&P Utilities Index. The 3 year total return chart assumes $100 invested on December 31, 2003 in the same security and indices. The information included under the heading Performance Graph shall not be considered filed for purposes of Section 18 of the Securities Exchange Act of 1934 or incorporated by reference in any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934.

Holders

As of May 15, 2007, there were approximately 6,857 record holders of our common stock, par value $0.01 per share.

Dividends

We do not currently pay dividends on our common stock. We intend to retain our future earnings, if any, to finance the future development and operation of our business. Accordingly, we do not anticipate paying any dividends on our common stock in the foreseeable future.

Under the terms of our Senior Secured Credit Facilities, which we entered into with a commercial bank syndicate, we are not allowed to pay cash dividends. In addition, under the terms of a guaranty we provided to the utility customer in connection with the AES Thames project, we are precluded from paying cash dividends on our common stock if we do not meet certain net worth and liquidity tests. The terms of the indentures governing our outstanding Second Priority Senior Secured Notes also restrict our ability to pay dividends.

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

See Item 12 (d) of this Form 10-K for information regarding Securities Authorized for Issuance under Equity Compensation Plans.

ITEM 6. *SELECTED FINANCIAL DATA*

The following table sets forth our selected financial data as of the dates and for the periods indicated. You should read this data together with *Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations* and our consolidated financial statements and the notes thereto included in Part II, Item 8 in this Annual Report on Form 10-K. The selected financial data for each of the years in the three year period ended December 31, 2006 have been derived from our audited consolidated financial statements. The information presented in the following tables has been adjusted to reflect the restatement of our financial results which is more fully described in Note 1 of the consolidated financial statements of the Company included in this Form 10-K. Our historical results are not necessarily indicative of our future results.

Acquisitions, disposals, reclassifications and changes in accounting principles affect the comparability of information included in the tables below. Please refer to the Notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K for further explanation of the effect of such activities. Please also refer to Item 1A and Note 22 to the Consolidated Financial Statements included in Item 8 of this Form 10-K for certain risks and uncertainties that may cause the data reflected herein not to be indicative of our future financial condition or results of operations.

SELECTED FINANCIAL DATA

Statement of Operations Data	Year Ended December 31, 2006	2005 (Restated)(1)	2004 (Restated)(1)	2003 (Restated)(3)	2002 (Restated)(3)
	(in millions, except per share amounts)				
Revenues	$ 12,299	$ 11,021	$ 9,392	$ 8,352	$ 7,322
Income (loss) from continuing operations	286	574	268	289	(1,922)
Discontinued operations, net of tax	(46)	34	32	(787)	(1,744)
Extraordinary item, net of tax	21				
Cumulative effect of change in accounting principle, net of tax		(3)		41	(376)
Net income available to common stockholders	$ 261	$ 605	$ 300	$ (457)	$ (4,042)
Basic income (loss) earnings per share:					
Income (loss) from continuing operations	$ 0.44	$ 0.89	$ 0.42	$ 0.48	$ (3.57)
Discontinued operations	(0.07)	0.05	0.05	(1.32)	(3.23)
Extraordinary item, net of tax	0.03				
Cumulative effect of change in accounting principle		(0.01)		0.07	(0.70)
Basic income (loss) earnings per share	$ 0.40	$ 0.93	$ 0.47	$ (0.77)	$ (7.50)
Diluted income (loss) earnings per share:					
Income (loss) from continuing operations	$ 0.43	$ 0.87	$ 0.41	$ 0.48	$ (3.57)
Discontinued operations	(0.07)	0.05	0.05	(1.32)	(3.23)
Extraordinary item, net of tax	0.03				
Cumulative effect of change in accounting principle		(0.01)		0.07	(0.70)
Diluted income (loss) earnings per share	$ 0.39	$ 0.91	$ 0.46	$ (0.77)	$ (7.50)

Balance Sheet Data:	December 31, 2006	2005 (Restated)(1)	2004 (Restated)(3)	2003 (Restated)(3)	2002 (Restated)(3)
	(in millions)				
Total assets	$ 31,163	$ 28,960	$ 28,388	$ 29,130	$ 34,516
Non-recourse debt (long-term)	$ 10,102	$ 10,638	$ 11,155	$ 10,538	$ 5,610
Non-recourse debt (long-term)-Discontinued operations	$ 57	$ 133	$ 157	$ 219	$ 4,275
Recourse debt (long-term)	$ 4,790	$ 4,682	$ 5,010	$ 5,862	$ 6,755
Stockholders equity (deficit)	$ 3,036	$ 1,626	$ 953	$ (121)	$ (823)(2)

(1) See Note 1 to the Consolidated Financial Statements included in Item 8 of this Form 10-K for information related to restated Consolidated Financial Statements.

(2) A $28 million reduction to Stockholder s equity was recognized as of January 1, 2002 as the cumulative effect of the correction of errors for all periods preceeding January 1, 2002. The correction was not material to the financial data presented herein as of and for the five years ended December 31, 2002 - December 31, 2006.

(3) The impact of the restatement adjustments on stockholders equity was $(3), $(19) and $32 million as of December 31, 2004, 2003 and 2002, respectively. The impact of the restatement adjustments to net income was an increase to net losses of $5 million and $41 million for the years ended December 31, 2003 and 2002, respectively.

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

The accompanying management s discussion and analysis of financial condition and results of operations set forth in this Item 7 is restated to reflect the correction of errors that were contained in the Company s consolidated financial statements and other financial information for the years ended December 31, 2002 through 2005 as discussed below and in Note 1 of the Consolidated Financial Statements. In addition, the prior period financial statements have been restated to reflect the change in the Company s segments as discussed below and in Note 22 of the Consolidated Financial Statements. The following management s discussion and analysis of financial condition and results of operations should be read in conjunction with our restated consolidated financial statements and the related notes.

Restatement Of Consolidated Financial Statements

Background

The Company has previously identified certain material weaknesses related to its system of internal control over financial reporting. These material weaknesses, as described in the Company s previously filed Form 10-K for the year ended December 31, 2005 included the following general areas:

- Aggregation of control deficiencies at our Cameroonian subsidiary;
- Lack of U.S. GAAP expertise in Brazilian businesses;
- Treatment of intercompany loans denominated in other than the functional currency;
- Derivative accounting; and
- Income taxes.

In part, the continuing remediation of these material weaknesses resulted in the identification of certain material financial statement errors. The Company has restated its financial statements for years ended prior to December 31, 2005 on March 30, 2005, January 19, 2006 and April 4, 2006 largely as a result of material weaknesses. As part of the Company s plan to eliminate these material weaknesses in internal control over financial reporting, the Company has embarked on a program, over a several year period, to improve the quality of its people, processes and financial systems. This has included a broad restructuring of the global finance organization to operate on a more centralized basis and the recruitment of additional accounting, financial reporting, income tax, internal control and internal audit staff around the world.

During the fourth quarter of 2006, in conjunction with these improvements, continued remediation of some of our material weaknesses and overall strengthening of controls across our businesses, the Company identified certain additional errors which required the restatement of previously issued consolidated financial statements for the years ended December 31, 2004 and 2005; and for the previously issued interim periods ending March 31, June 30 and September 30, 2005 and 2006.

The Company s remediation efforts for certain material weaknesses reported as of December 31, 2005, as well as improvements to controls across the Company, resulted in the identification of errors included in the current restatement. In addition, a number of immaterial errors were identified as a result of the continued strengthening of the global finance organization. The Company believes that the increase in technical tax and accounting expertise, increased staffing levels at certain of our businesses and at our corporate office, and a focused effort on increasing the number of financial audit activities have contributed to the overall improvement of the accuracy of our financial statements. It also resulted in the identification of material weaknesses in areas not previously reported, although not all weaknesses contributed to the need to restate the consolidated financial statements. For further discussion of our material weaknesses, see Item 9A of this Annual Report on Form 10-K.

The restatement adjustments resulted in a decrease to previously reported income from continuing operations and net income of $24 million for the year ended December 31, 2005 and an increase of $2 million for the year ended December 31, 2004. It also resulted in a decrease to previously reported income from continuing operations and net income of $3 million for the three months ending March 31, 2006, an increase to net income of $10 million for the six months ending June 30, 2006 and an increase to net income of $30 million for the nine months ending September 30, 2006. These interim period adjustments for the first three quarters of 2006 were largely the result of reversing errors previously corrected in these periods, which were not previously considered material either to the period in which they were corrected or the prior period to which they actually arose. Additionally, the cumulative adjustment for all periods prior to 2004 resulted in an increase to retained deficit of $50 million.

The following table quantifies the net impact of the restatement corrections by key income statement line items for the years ended December 31, 2005 and 2004 and includes the resulting impact on diluted earnings per share from continuing operations. The primary line items affected include revenue, cost of sales, gain (loss) on foreign currency transactions, income tax expense and the related impacts on minority interest expense.

	Year Ended December 31, 2005	2004
	(in millions, except per share amounts)	
Income from continuing operations as previously reported	$ 598	$ 266
Changes in income from continuing operations from restatement due to:		
Increase in revenue	25	1
Decrease in cost of sales	5	18
(Increase) decrease in general and administrative expense	(4)	1
Increase in other income	11	1
(Increase) in goodwill and asset impairment expense	(6)	(1)
(Increase) decrease in foreign currency transaction losses	(13)	27
Decrease in equity earnings of affiliates	(6)	(7)
(Increase) in income tax expense	(27)	(24)
(Increase) in minority interest and other(1)	(9)	(14)
(Decrease) increase in income from continuing operations	(24)	2
Income from continuing operations as restated	$ 574	$ 268
Diluted earnings per share from continuing operations as previously reported	$ 0.90	$ 0.41
Changes due to restatement effects	(0.03)	
Diluted earnings per share from continuing operations as restated	$ 0.87	$ 0.41
Diluted shares outstanding	664.6	648.1

(1) Minority interest and other includes $12 million and $13 million of minority interest expense for the periods ending December 31, 2005 and December 31, 2004, respectively, related to the impact of the restatement adjustments at entities with minority interests.

The Company has been cooperating with an informal inquiry by the SEC Staff concerning the Company s restatements and related matters, and has been providing information and documents to the SEC Staff on a voluntary basis. Because the Company is unable to predict the outcome of this inquiry and the SEC Staff may disagree with the manner in which the Company has accounted for and reported the financial impact of the adjustments to previously filed financial statements, there may be a risk that the inquiry by the SEC could lead to circumstances in which the Company may have to further restate previously filed financial statements, amend prior filings or take other actions not currently contemplated.

The restatement adjustments include several key categories as described below:

Brazil Adjustments

Prior year errors related to certain subsidiaries in Brazil include the following:

- decrease of the U.S. GAAP fixed asset basis and related depreciation at Eletropaulo of $21 million in 2005 and $16 million in 2004 (the impact net of tax and minority interest is $4 million in 2005 and $4 million in 2004); and

- other errors identified through account reconciliation or review procedures.

The cumulative impact on net income was an increase of $6 million and $3 million for the years ended December 31, 2005 and 2004, respectively.

EDC

Prior year errors related to the Company s Venezuelan subsidiary, EDC, include the following:

- $22 million revenue increase predominantly related to an error in updating the current tariff rates in the unbilled revenue calculation for 2005,

- $10 million increase in foreign currency transaction expense posted incorrectly to the balance sheet in 2005, and

- other errors identified through account reconciliation or review procedures.

The cumulative impact of all EDC adjustments on net income was an increase of $2 million for each of the years ended December 31, 2005 and 2004.

Capitalization of Certain Costs

Certain errors were discovered with fixed asset balances at several of the Company s facilities related to capitalization of development costs, overhead and capitalized interest. The cumulative impact on net income for capitalization errors was a decrease of $4 million for the year ended December 31, 2005 and a decrease of $2 million for the year ended December 31, 2004.

Derivatives

Adjustments were identified resulting from the detailed review of certain prior year contracts and include the following:

- the evaluation of hedge effectiveness; and

- the identification and evaluation of derivatives.

The most significant adjustment involved a power sales agreement signed in 2002 between the Company s generation facility in Cartagena, Spain, an unconsolidated subsidiary accounted for using the equity method of accounting, and its power offtaker. The power sales agreement had a pricing component that was tied to the U.S. dollar, although the entity s own functional currency was the Euro and that of the offtaker was the Euro. In addition, a maintenance service agreement related to the Cartagena facility included a pricing mechanism that was tied to changes in the U.S. dollar, when the entity s functional currency was the Euro and the service provider s functional currency was the Yen.

Under the guidance of Statement of Financial Accounting Standard (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, these contracts contained embedded derivatives that are required to be bifurcated from the contract and recorded at fair value with changes in fair value recognized in the results of operations. The net result of these adjustments was a decrease of $3 million and an increase of $4 million in equity in earnings of affiliates for the years ended December 31, 2005 and 2004, respectively.

The cumulative impact of all derivative adjustments on net income was a decrease of $4 million in 2005 and an increase of $5 million in 2004.

Income Tax Adjustments

Income tax adjustments relate primarily to the following:

- A $20 million adjustment to correct income tax expense in the fourth quarter of 2005 as a result of an incorrect 2004 tax return to accrual adjustment, previously disclosed in the Company s Form 10-Q for September 30, 2006; and

• A $21 million adjustment to record income tax benefit in 2004 as a result of a change in local income tax reporting for leases in Qatar, offset by adjustments to correct income tax expense for certain state deferred tax assets and other miscellaneous items.

The net impact of individual income tax adjustments resulted in an increase to income tax expense of approximately $18 million in 2005 and $7 million in 2004. The cumulative impact on income tax expense as a result of all restatement adjustments was an increase of approximately $27 million for the year ended December 31, 2005 and an increase of approximately $24 million for the year ended December 31, 2004.

Other Adjustments

As a result of work performed in the course of our year end closing process, certain other adjustments were identified which decreased net income by $6 million for the year ended December 31, 2005 and increased net income by $1 million for the year ended December 31, 2004.

Balance Sheet Adjustments

Adjustments at certain businesses in Brazil

The Company s Brazilian business, Sul, records customer receipts used to provide line extensions as an offset against property, plant and equipment. However, the regulatory body of Brazil never issued any guidance with respect to the treatment of these customer receipts. As such, we believe that a more appropriate classification of these customer receipts would have been as a regulatory liability given that the actual treatment as an offset against property, plant and equipment was never approved by the regulatory body of Brazil. Additionally, the regulatory liability treatment provides for the possibility of a future obligation back to the customers, which was confirmed by a recent regulatory ruling. The increase to property, plant and equipment and increase to long-term regulatory liabilities was $93 million and $62 million at December 31, 2005 and 2004, respectively.

Cartagena Deconsolidation

Upon the Company s adoption of Financial Interpretation No.46, Variable Interest Entities (FIN No. 46R), as of January 1, 2004, the Company incorrectly continued to consolidate our business in Cartagena, Spain. An adjustment was made to deconsolidate the Cartagena balance sheet and statement of operations and to reflect AES share of the results of its operations using the equity method of accounting. This resulted in a decrease to investments in affiliates of $55 and $39 million; a decrease in net property, plant and equipment of $570 and $387 million; and a decrease in non-recource debt of $579 and $497 million at December 31, 2005 and 2004, respectively.

Restricted Cash

Certain balance sheet reclassifications were recorded at December 31, 2005 and December 31, 2004 that were the result of errors in the presentation of restricted cash. These reclasses resulted in a reduction in cash and cash equivalents and an increase in restricted cash by $63 million and $97 million, in 2005 and 2004, respectively

Share-based Compensation

The Company recently concluded an internal review of accounting for share-based compensation (the LTC Review), which originally was disclosed in the Company s Form 8-K filed on February 26, 2007. As a result of the LTC Review, the Company identified certain errors in its previous accounting for share-based compensation. These errors required adjustments to the Company s previous accounting for these awards under the guidance of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB No. 25), Financial Accounting Standards Board (FASB) Statement No. 123, *Accounting for Stock-Based Compensation* (FAS No. 123) and FASB Statement No. 123R (revised 2004), *Share-Based Payment* (FAS No. 123R). As described below, the Company is recording adjustments to its prior financial statements resulting in additional cumulative pre-tax compensation expense for the years 2000-2005 of $36 million ($26 million net of taxes). None of these adjustments, individually or in the aggregate, is quantitatively material to any period presented.

In addition, the Company has identified accounting for share-based compensation as a material weakness and has prepared a remediation plan to strengthen further its granting and accounting practices to avoid similar errors in the future. See Item 9A Disclosure Controls and Procedures of this Form 10-K for further explanation of the material weakness and the Company s remediation plans.

Background of the LTC Review

Beginning in mid-2006 the Company conducted limited assessments of its share-based compensation practices. Based on those assessments, it did not appear likely that the potential accounting adjustments relating to share-based compensation issues identified as of that time would be material to the Company s prior period financial statements. However, information subsequently developed by the Company s Internal Audit group indicated that there had been control deficiencies and inadequate oversight related to historical granting practices and accounting for share-based compensation.

Following consideration of this information, the Company determined that a more comprehensive review of prior period awards was warranted. Accordingly, in early February 2007, the Company requested that an outside consulting firm assist with the collection and processing of data relating to the Company s share-based compensation awards. The outside consulting firm also provided a team of forensic accountants to assist the Company with its: (i) evaluation of relevant Securities and Exchange Commission (SEC) and FASB guidance relating to share-based compensation; (ii) implementation of procedures for review of electronic data, including e-mails; and (iii) analysis of the information used to determine measurement dates, strike prices and valuations required to reach the resulting accounting adjustments. The Company also asked an outside law firm to assist the Company with the LTC Review. This law firm had already been assisting the Company in responding to requests for documents and information from the SEC Staff principally relating to the Company s restatements for the years 2002-2005. As disclosed in a Form 8-K filed on March 19, 2007, the Financial Audit Committee of the Company s Board of Directors formed an Ad Hoc Committee of three independent directors to review the Company s procedures, conclusions and recommendations regarding the LTC Review, as described herein.

Purposes and Scope of the LTC Review

The LTC Review was designed and conducted principally to determine whether any adjustments to the Company s prior period financial statements were required as a result of incorrect accounting for share-based compensation, which includes stock options and restricted stock units. A secondary purpose of the LTC Review was to evaluate the Company s historical practices and procedures for making share-based compensation awards, including the conduct of individuals involved in the granting process.

The Company determined that a ten-year review period covering the years 1997-2006 (the Review Period) was appropriate. Supporting documentation was more readily available in more recent years and, in many instances, the Company experienced difficulty locating and/or gathering documentation for the years 1997-1999. Therefore, the Company determined that a review of years preceding 1997 was unlikely to result in information susceptible to meaningful analysis.

A significant accounting issue identified in the LTC Review related to the determination of the measurement date with respect to share-based compensation awards. During the Review Period, the Company had generally used the indicated grant date as the measurement date for accounting purposes, when in many cases the indicated grant date actually preceded the measurement date as correctly defined under Generally Accepted Accounting Principles (GAAP). The U.S. GAAP technical accounting literature in effect during the accounting periods under review defined the measurement date for purposes of determining share-based compensation expense as the date on which the Company finalized an individual s share-based award, to include the number of units awarded at a determinable strike price.

The Company gathered documentation and conducted analysis related to measurement dates with respect to all of the grants awarded in the Review Period, a total of approximately 29,600 stock option grants, representing approximately 45,380,000 options as well as approximately 4,000,000 restricted stock units for non-directors. These grants included both the Company s annual compensation awards, known as on-cycle grants, and all awards made at other times, referred to as off-cycle grants. The LTC Review was designed to assess the appropriate measurement date for each of the various types of grants awarded during the Review Period. The Company considered SEC guidance and GAAP in evaluating known facts and circumstances in an attempt reasonably to determine the date that the share-based compensation awards were final. The Company collected information through targeted searches of various sources, including human resources and accounting databases, paper and electronic files and servers, Board of Directors and Compensation Committee meeting minutes, payroll records, and acquisition and business development documentation. The Company also interviewed certain current and former employees, officers and directors.

Although there generally was less documentation readily available for the years 1997-1999, the Company did review grants in those years, and based on available information, attempted to make a reasonable assessment of the correct measurement dates and potential accounting adjustments for the purposes of assessing whether any charge from that period could be material to the Company s financial statements in those years. Based on this analysis, the Company determined that any errors identified during that period would not have resulted in a material impact to the Company s stockholders equity and no adjustments were made.

The Company s Accounting Adjustments

As a result of the LTC Review, the Company has determined that adjustments resulting in charges for share-based compensation should be recorded for the years 2000 through 2005. The additional cumulative pre-tax compensation expense totals $36 million ($26 million net of taxes). The effect of recognizing additional non-cash, share-based compensation expense resulting from the charges mentioned above by year is as follows:

Fiscal Year Ended (in millions)	Pre-Tax Expense	After-Tax Expense
2000	$ 8	$ 6
2001	$ 15	$ 11
2002	$ 8	$ 5
2003	$ 4	$ 3
2004	$	$
2005	$ 1	$ 1

The Company also is recording a charge of $0.6 million (pre-tax) relating to the first three previously reported quarters of 2006, which primarily relate to prior year grants in which expense was carried forward to 2006.

None of these adjustments, individually or in the aggregate, is quantitatively material to any period presented; however, the Company will reflect these adjustments by reducing stockholders equity by $25.2 million as of January 1, 2004 for the cumulative effect of the correction of errors for the periods from January 1, 2000 through December 31, 2003. General and administrative expense will be adjusted for the years ending December 31, 2004 and 2005 and the first three quarters of 2006 as outlined above.

Annual On-Cycle Awards. Compensation charges for annual on-cycle grants were determined based upon facts and circumstances relating to the dates the awards were final and the selection of the appropriate strike prices. The Company determined new measurement dates based on a determination of the date an award was final using the following methodology. Grants to Executive Officers and certain other senior executives (Senior Leaders) were considered to be final for accounting purposes upon Compensation Committee approval of a fixed number of options at a specific exercise price, or in certain years based on subsequent action by the Company establishing the grant date and strike price. Grants to all other employees were considered to be final for accounting purposes on the date that management completed its allocation of substantially all awards to the pool of employees receiving awards. In addition to measurement date changes, the LTC Review identified three years in which the Company had set the strike price for the annual on-cycle grants either as the opening price or as the intra-day low trading price of the Company s stock during a four-day period over which a Board meeting was held. To determine the fair market value of the stock on the re-determined measurement date for accounting purposes, the Company used the closing price of the stock on that date. Accordingly, for financial accounting purposes, the amount of compensation expense recorded by the Company reflects both measurement date changes and intrinsic value changes for annual on-cycle awards. The predominant causes of the charges relating to on-cycle grants were (i) with respect to Executive Officers and Senior Leaders, use of a grant date associated with an annual Board meeting, where the grant date and strike price had not been determined with finality until several days after the meeting; and (ii) with respect to all other employees, the failure to finalize a complete and accurate schedule of the awards to be made to the employees contemporaneously with the intended grant date.

Off-Cycle Grants. Compensation charges for off-cycle grants also were based primarily upon the dates the awards were final. The majority of the measurement date changes with respect to off-cycle grants related to the following five categories: (1) awards to newly hired employees; (2) awards upon promotions of existing employees or other change in status; (3) awards made in conjunction with transactions or other successful business development efforts; (4) Founders and other similar awards made in recognition of outstanding service, and (5) corrections to previous awards subsequently determined to have been erroneous.

The predominant cause of the measurement date errors in each of these categories of awards was the lack of adequate contemporaneous documentation supporting the intended grant. Accordingly, the amount of compensation expense recorded by the Company for these categories of off-cycle awards is based primarily upon measurement date changes. The adjustments reflect available evidence concerning the dates on which: (i) the recipients were entitled to receive the awards, (ii) the grants were intended to be made, and (iii) the terms of the grants were final.

In addition to the categories above, off-cycle grants also were defined to include modifications of prior grants. Compensation charges for grant modifications were based upon an analysis of changes to vesting and exercise periods. As a result of its review, the Company has determined that certain modifications were calculated using an incorrect method and others were not communicated to appropriate accounting personnel. The most significant modification relates to a grant to a former CEO that was erroneously accounted for by using an intrinsic value calculation instead of a fair value calculation following the Company s decision to adopt FAS 123 effective January 1, 2003. The Company is recording a $3 million charge to account for this error for the year 2003.

Summary of Significant Charges By Grant Year

Set forth in this section is a summary of the charges resulting from grants awarded in the years 2000, 2001 and 2003, which make up more than 95% of the additional expenses requiring adjustments to the prior period financial statements. This information is different than the discussion and table above, which described the effect of recognizing these additional charges over the applicable accounting periods in the

Company s financial statements. For these years, further information concerning the type of grant (on-cycle or off-cycle), the categories of the recipients and the nature of the change resulting in the adjustment is set out below.

For grants made in 2000, the total charge resulting from the LTC Review is approximately $23 million. Of that amount, approximately $4 million resulted from the changes to the on-cycle grants to Executive Officers and Senior Leaders. Of the remaining amount, approximately $17 million resulted from the changes to the on-cycle grants to all other employees, and approximately $2 million resulted from off-cycle grants.

For grants made in 2001, the total charge resulting from the LTC Review is approximately $9 million. Of that amount, approximately $7 million resulted from the changes to on-cycle grants to Executive Officers and Senior Leaders. Of the remaining amount, approximately $250,000 resulted from the changes to the on-cycle grants to all other employees, and approximately $1 million resulted from off-cycle grants.

For grants made in 2003, the total charge is approximately $6 million. Of this amount, $3 million related to the modification to a grant to a former CEO as described above, and approximately $800,000 related to a grant to a director approved by shareholders where the grant date was recorded as having been finalized on the date of an earlier Board meeting. The remaining charges resulted from changes to certain on-cycle and off-cycle grants.

The Company s Review of Historic Practices

As noted, the primary purpose of the LTC Review was to conduct a comprehensive review of the Company s accounting for share-based compensation and to record any required adjustments in its financial statements. The LTC Review was not an independent investigation relating to historic practices and procedures. However, during the course of the LTC Review, the Company identified certain historical practices raising issues relating to share-based compensation and conducted a review of those practices, limited in scope as noted herein. Based on the information to date, the Company has identified certain historical issues and practices of concern relating to the annual on-cycle and off-cycle grants, which fall within the following five categories: (1) with respect to the 1997-1998 annual on-cycle grants, reported ratification of undocumented prior on-cycle grants by the Compensation Committee; (2) with respect to the 1999-2001 annual grants, after-the-fact selection of low strike prices within the four-day period during which Board meetings were held, and inaccurate Compensation Committee meeting minutes relating to grant date and strike price selection; (3) issuance of off-cycle grants prior to 2004 based on apparent, but not actual, delegation of authority, as well as general deficiencies in administration of off-cycle grants; (4) failure to establish and/or comply with certain formal corporate governance procedures in periods through 2004; and (5) lack of and/or insufficient controls and procedures, and/or lack of knowledge of applicable accounting standards, in connection with administration of share-based compensation. The Company notes that the senior officers who were primarily involved in the selection of the prices of the annual on-cycle grants from 1999-2001 were the Company s President and CEO at the time, who retired in 2002; the Company s CFO at the time, who left full time employment with the Company in early 2006 (he remains under an employment agreement through March 2008, although he is not active in management); and the Company s General Counsel at the time, who presently is the Company s Executive Vice President and President, Alternative Energy and is no longer involved in the Company s legal functions or Board consideration or approval of share-based compensation.

The information developed in the LTC Review did not establish that any officer or director of the Company manipulated the selection of grant dates or strike prices with actual knowledge that they were violating or causing the Company to violate accounting principles or requirements of the Company s stock options plans, or that there was any effort to conceal information relating to the selection of grant dates or strike prices from the Company s outside auditors. However, all of the matters described herein with respect to the Company s general views and issues arising from the LTC Review are qualified by the fact that, in light of the limitations discussed herein, there may be additional documents, witnesses or other information not reviewed that might have indicated a different result.

The limitations of the LTC Review include the fact that the Company did not review backups of data from the First Class System (First Class), the Company s e-mail system prior to January 1, 2002, when the Company switched to Microsoft Outlook. The Company also did not attempt to restore approximately 460 computer tapes (the Backup Tapes) that are stored by an off-site storage vendor. The Company believes that these tapes comprise backups of certain Company electronic data (including e-mail) backed up on certain dates from approximately late 2001 through early 2004, but the Company has not located an index identifying the contents of the tapes.

The Company decided not to attempt to restore and review First Class or the Backup Tapes because: (i) the Company was able to review certain electronic data, including for the years 1997-2002, as well as paper files and other available information relating to the majority of the grants made during the Review Period; (ii) the Company believes that it is unlikely that information from these sources would materially alter the accounting adjustments that have been determined to be necessary; (iii) the Company has implemented or will implement measures necessary to provide effective controls and procedures in these areas; (iv) of the senior officers who were primarily involved in the selection of the prices of the annual on-cycle grants from 1999-2001, the former CEO is no longer with the Company, the former CFO is no longer an officer and is not active in the Company s management, and the former General Counsel has a different position in the Company that does not involve corporate legal responsibilities or participation in Board consideration or approval of share-based compensation; and (v) based on consultation with a reputable information technology vendor, the Company determined that neither First Class nor the Backup Tapes could be restored for review without causing substantial delays in the LTC Review. In addition, while the Company conducted more than twenty interviews with persons who, by virtue of their position or otherwise, were believed to be most likely to have relevant knowledge, the Company did not interview every director or employee who may have had any involvement with options grants or accounting for share-based compensation.

Sale of EDC

On February 22, 2007, we entered into a definitive agreement with Petróleos de Venezuela, S.A., (PDVSA), pursuant to which we have agreed to sell to PDVSA all of our shares of EDC. The agreement is dated as of February 15, 2007.

Subject to the terms and conditions in the agreement, PDVSA has agreed to pay us a purchase price of US$739 million at closing, net of any withholding taxes. In addition, the agreement provided for the payment of a US$120 million dividend in 2007. On March 1, 2007, the shareholders of EDC approved and declared a US$120 million dividend, payable on March 16, 2007, to all shareholders on record as of March 9, 2007. A wholly-owned subsidiary of the Company is the owner of 82.14% of the outstanding shares of EDC, and therefore, on March 16, 2007, this subsidiary received the equivalent of approximately US$99 million in Bolivares that is currently being held in trust at a U.S. bank until the funds can be converted to U.S. Dollars. Under the terms of the purchase and sale agreement with the Republic of Venezuela, PDVSA has agreed to ensure that the Company s portion of the dividend is converted by the Venezuelan government s Foreign Exchange Commission, CADIVI, from Bolivares into U.S. Dollars at the current official exchange rate within 90 days of the dividend payment date. As of the date of this filing, the conversion of the Company s portion of the dividend from Bolivares to U.S. Dollars has been submitted to CADIVI and is awaiting their approval.

The agreement provided that PDVSA would acquire our EDC common shares in a tender offer. PDVSA commenced and publicly announced the commencement of concurrent tender offers in Venezuela and the United States (the Offers), on April 9, 2007. The Offers provided for the purchase of 2,704,445,687 of EDC common shares at a U.S. Dollar equivalent amount of $0.2734 per common share, which is consistent with the price per share implied by the purchase price within the agreement. The closing of the Offers occurred on May 8, 2007 and the actual transfer of the shares along with payment of the purchase price occurred on May 16, 2007.

As a result of signing this agreement, we have concluded that a material impairment of our investment in EDC has occurred, which will be recorded in the first quarter ending March 31, 2007. This material impairment represents the net book value of our investment less the estimated purchase price. Management estimates that this pre-tax, non-cash charge will be in the range of $600 to $650 million.

We purchased a controlling interest in EDC in 2000. EDC is the largest private electric utility in Venezuela. It is a provider of power and light to approximately one million customers in the Caracas metropolitan area. EDC also owns and operates five generation plants with a total of 2,616 MW of generation capacity. These facilities collectively represent approximately 14% of the electricity consumed in Venezuela.

For the year ended December 31, 2006, EDC represented 5% of AES consolidated revenues and 12% of the Latin America Utilities segment revenues, 5% of AES consolidated gross margin and 17% of the Latin America Utilities segment gross margin. In addition, EDC represented 37% of AES consolidated net income and 36% of basic earnings per share. Excluding the net after-tax loss impact of $512 million related to the sale of Eletropaulo shares and debt restructuring, EDC represented 12% of AES consolidated net income and 12% of basic earnings per share. AES received a dividend of approximately $101 million from EDC in 2006. EDC s five generation plants represented approximately 7% of AES approximate 35 gigawatts of capacity installed.

Executive Summary

AES is one of the world s largest global power companies, providing essential electricity services in 27 countries on five continents. Our goal is to continue building on our traditional lines of business, while expanding into other essential energy-related areas. We believe that this is a natural expansion for us. As we move into new lines of business, we will leverage the competitive advantages that result from our unique global footprint, local market insights and our operational and business development expertise. We also will build on our existing capabilities in areas beyond power including greenhouse gas emissions offset projects, electricity transmission, water desalinization, and other businesses. As we continue to expand and grow our business we will maintain a focus on efforts to improve our business operations and management processes, including our internal controls over financial reporting.

Our business strategy is focused on global growth in our core generation and utilities businesses along with growth in related markets such as Alternative Energy, electricity transmission and water desalinization. We continue to emphasize growth through greenfield development, platform expansion, privatization of government-owned assets, and mergers and acquisitions and continue to develop and maintain a strong development pipeline of projects and opportunities. The Company sees growth investments as the most significant contributor to long-term shareholder value creation. The Company s growth strategies are complemented by an increased emphasis on portfolio management through which AES has and will continue to sell or monetize a portion of certain businesses or assets when market values appear significantly higher than the Companies own assessment of value in the AES portfolio.

Underpinning this growth focus is an operating model which benefits from a diverse power generation portfolio that is largely contracted, reducing fuel cost and demand risks, and from an electric utility portfolio heavily weighted to faster-growing emerging markets.

The Company anticipates that success with its business development activities will be the single most important factor in its financial success in terms of value creation and it is directing increasing resources in support of business development globally. The Company also anticipates that high oil prices, increasing regulation of greenhouse gases, faster than expected global economic growth and a weak dollar present opportunities for value creation, based on the Company s current business portfolio and business strategies. Slower global economic growth, which will impact demand growth for Utilities and some Generation businesses, is the most significant downside scenario affecting value creation. Other important scenarios that could impair future value include low oil prices and a strong dollar.

Business Overview

We are a global power holding company incorporated in Delaware in 1981. Through our subsidiaries, we operate a portfolio of electricity generation and distribution businesses and investments on five continents and in 27 countries.

Our Businesses

We operate two types of businesses. The first is our distribution and transmission business, which we refer to as Utilities, in which we operate electric utilities and sell power to customers in the retail (including residential), commercial, industrial and governmental sectors. These customers are typically end users of electricity. The second is our Generation business, where we sell power to wholesale customers such as utilities or other intermediaries. The revenues and earnings growth of both our Utilities and Generation businesses vary with changes in electricity demand.

Our Utilities business consists primarily of 13 distribution companies in seven countries with over 10 million end-user customers. All of these companies operate in a defined service area. This segment is composed of:

- integrated utilities located in:
- the United States Indianapolis Power & Light (IPL),
- Cameroon AES SONEL.
- distribution companies located in:
- Brazil AES Eletropaulo and AES Sul,
- Argentina Empresa Distribuidora La Plata S.A. (EDELAP), Empresa Distribuidora de Energia Norte (EDEN) and Empresa Distribuidora de Energia Sure (EDES),
- El Salvador Compañia de Alumbrado Eléctrico de San Salvador, S.A. de C.V. (CAESS), Compania, S. En C. de C.V. (AES CLESA), Distribuidora Electrica de Usulutan, S.A. de C.V. (DEUSEM) and Empresa Electrica de Oriente (EEO), and
- Ukraine Kievoblenergo and Rivneenergo.

Performance drivers for these businesses include, among other things, reliability of service, management of working capital, negotiation of tariff adjustments, compliance with extensive regulatory requirements and, in developing countries, reduction of commercial and technical losses.

Utilities face relatively little direct competition due to significant barriers to entry which are present in these markets. In this segment, we primarily face competition in our efforts to acquire businesses. We compete against a number of other participants, some of which have greater financial resources, have been engaged in distribution related businesses for periods longer than we have, and have accumulated more significant portfolios. Relevant competitive factors for Utilities include financial resources, governmental assistance, regulatory restrictions and access to non-recourse financing. In certain locations, our utilities

face increased competition as a result of changes in laws and regulations which allow wholesale and retail services to be provided on a competitive basis. We can provide no assurance that deregulation will not adversely affect the future operations, cash flows and financial condition of our Utilities business. The results of operations of our Utilities business are sensitive to changes in economic growth and regulation, abnormal weather conditions in the area in which they operate, as well as the success of the operational changes that have been implemented (especially in emerging markets).

In our Generation business, we generate and sell electricity primarily to wholesale customers. Performance drivers for our Generation business include, among other things, plant reliability, fuel costs and fixed-cost management. Growth in this business is largely tied to securing new power purchase agreements, expanding capacity in our existing facilities and building new power plants. Our Generation business includes our interests in 97 power generation facilities owned or operated under management agreements totaling over 35 gigawatts of capacity installed in 21 countries.

Approximately 68% of the revenues from our Generation business are from plants that operate under power purchase agreements of five years or longer for 75% or more of the output capacity. These long-term contracts reduce the risk associated with volatility in the market price for electricity. We also reduce our exposure to fuel supply risks by entering into long-term fuel supply contracts or through fuel tolling contracts where the customer assumes full responsibility for purchasing and supplying the fuel to the power plant. As a result of these contractual agreements, these facilities have relatively predictable cash flows and earnings. These facilities face most of their competition prior to the execution of a power sales agreement, during the development phase of a project. Our competitors for these contracts include other independent power producers and equipment manufacturers, as well as various utilities and their affiliates. During the operational phase, we traditionally have faced limited competition due to the long-term nature of the generation contracts. However, since competitive power markets have been introduced and new market participants have been added, we have and will continue to encounter increased competition in attracting new customers and maintaining our current customers as our existing contracts expire.

The balance of our Generation business sells power through competitive markets under short term contracts or directly in the spot market. As a result, the cash flows and earnings associated with these facilities are more sensitive to fluctuations in the market price for electricity, natural gas, coal and other fuels. However, for a number of these facilities, including our plants in New York, which include a fleet of low-cost coal fired plants, we have hedged the majority of our exposure to fuel, energy and emissions pricing for the next several years. These facilities compete with numerous other independent power producers, energy marketers and traders, energy merchants, transmission and distribution providers and retail energy suppliers. Competitive factors for these facilities include price, reliability, operational cost and third party credit requirements.

As described above, AES operates within two primary businesses, the generation of electricity and the distribution of electricity. AES previously reported its financial results in three business segments: contract generation, competitive supply and regulated utilities. As of December 31, 2006, we have changed the definition of our segments in order to report information by geographic region and by line of business. We believe this change more accurately reflects the manner in which we manage the Company.

Our businesses include Utilities and Generation within four defined geographic regions: (1) North America, (2) Latin America, (3) Europe, CIS and Africa, which we refer to as Europe & Africa and (4) Asia and the Middle East, which we refer to as Asia . Three regions, North America, Latin America and Europe & Africa, are engaged in both our Generation and Utility businesses. Our Asia region only has Generation businesses. Accordingly, these businesses and regions account for seven segments. Corporate and Other includes corporate overhead costs which are not directly associated with the operations of our seven primary operating segments; interest income and expense; other intercompany charges such as management fees and self-insurance premiums which are fully eliminated in consolidation; and development and operational costs related to our Alternative Energy business which is currently not material to our presentation of operating segments.

Recent Initiatives

We are developing an Alternative Energy business. Alternative Energy includes strategic initiatives such as wind generation and other renewable energy sources, liquefied natural gas regasification (LNG), greenhouse gas emissions offset projects and new technologies. Of these initiatives, we currently only have wind generation facilities that are operational. Our Buffalo Gap wind project, which is located in Texas, began full commercial operations in April 2006. An expansion of Buffalo Gap, called Buffalo Gap 2, is currently under construction. We also acquired wind generation assets in California from Enron Wind Systems. In Europe, we have acquired stakes in wind development businesses in Scotland, France, and Bulgaria.

We currently have three LNG projects that are in pre-construction phases of development. We are also pursuing projects which will allow us to develop greenhouse gas emission offsets. To that end, we have developed a joint venture with AgCert International called AES AgriVerde, which will deploy greenhouse gas emissions reduction technology in selected countries in Asia, Europe and North Africa. Although, Alternative Energy represents a very small portion of our business compared to Utilities and Generation, Alternative Energy is an important initiative in our long-term strategy because we believe it may represent a significant growth opportunity for us.

Some of the important drivers of performance for us developing our alternative energy businesses include continued government support through regulation and incentives, continued progress towards liquid and transparent markets, particularly in the area of greenhouse gas emission credit trading and the successful identification, execution and commercialization of new market opportunities in these nascent markets. While this initiative represents a growth opportunity for us, alternative energy is not material to our financial statements at this time.

2006 Performance Highlights

	December 31, 2006 ($ in millions)	2005	2004
Revenue	$ 12,299	$ 11,021	$ 9,392
Gross Margin	3,631	3,199	2,791
Gross Margin as a % of Revenue	29.5 %	29.0 %	29.7 %
Diluted Earnings (Loss) Per Share from Continuing Operations	0.43	0.87	0.41
Net Cash Provided by Operating Activities	2,411	2,154	1,608

Revenue We achieved record revenues of $12.3 billion, an increase of 11.8% from $11.0 billion last year. Higher power prices, largely driven by the pass-through of higher fuel costs, together with increased demand and favorable foreign currency trends were the primary contributors.

Gross margin **We achieved record gross margin of $3.6 billion, an increase of 12.5% from $3.2 billion in 2005. Favorable volume and foreign currency translation were the primary contributors to the increase.**

Earnings per share Diluted earnings per share from continuing operations were $0.43 compared to $0.87 in 2005. This decrease was primarily driven by the Brazil restructuring charges. Excluding the Brazil restructuring charges, earnings per share increased due to higher gross margin (primarily Latin American volume and foreign exchange) and lower net interest expense (debt retirements and lower interest rates). These gains were partially offset by higher general and administrative expenses resulting from increased development spending. **The restructuring of our Brazil holding company, Brasiliana, eliminated restrictions on dividend payments to AES from three of our four principal Brazil businesses (Eletropaulo, Tiete, and Uruguiana). The restructuring resulted in non-cash after-tax charges totaling $512 million, or $0.76 per share, primarily related to a loss on sale of Eletropaulo stock in a secondary offering recognizing deferred currency adjustments and certain debt prepayment premiums, partially offset by favorable tax benefits.**

Net cash from operating activities **We also achieved record cash flows from operating activities of $2.4 billion, 9.1% higher than 2005. Higher operating cash flows primarily reflect an increase in net earnings adjusted for non cash items.**

Key Initiatives

People Development

People development continues to be a major initiative as we look to improve our technical and leadership skills. We continued to expand the AES learning Center, a program developed in partnership with the University of Virginia s Darden School of Business, which offers a range of courses on effective leadership, general management and functional skills, such as finance. In 2006, the Center launched a Financial Leadership Development Program to elevate performance among our financial groups worldwide. We also expanded the program internationally to Brazil, Cameroon, Kazakhstan, the Middle East and Ukraine. In addition to classroom training, we added an online AES Learning Center and now have an inventory of more than 150 technical and managerial courses offered online, making these classes available on a real-time basis.

We continue to place top priority on ensuring a safe working environment for AES people, contractors and customers. In 2006, we saw continuing improvements in the number of lost time accidents (LTAs) at our businesses.

Material Weaknesses

Over the course of the past year, the Company has worked diligently to continue to strengthen its controls over financial reporting, with particular emphasis on remediating its material weaknesses related to:

- US GAAP accounting expertise in Brazil;
- Income tax accounting;
- Derivative accounting; and
- Foreign currency implications of certain intercompany loans.

This effort involved a continuing review of current processes, implementation of remediation plans and a focus on staffing with the right level and quality of technical accounting resources. We have focused our internal audit resources on performing additional targeted financial statement audits and have brought in outside expertise in the areas of derivatives and tax to help us expedite our improvement plans. In addition to this specific focus, the Company embarked upon a program to assess the capabilities of its financial staff on a worldwide basis and develop related hiring and training programs. We have approved a program to accelerate our implementation of integrated financial systems for our generation plants, which will allow for further automation of currently manual processes and more timely submission and review of financial statements.

As a result of these continued efforts, we did identify certain prior year errors which caused the Company to restate prior year results again. Even so, we feel confident that the financial and control organizations are taking the right steps, with full management support, to help us ensure that we are able to produce accurate and timely financial statements in the future.

Debt Restructuring

Our existing businesses continued to focus on plant and distribution system operational excellence, reliability and customer service. We also benefited from favorable debt capital markets in a number of countries to restructure and refinance debt, extend maturities, and increase liquidity. In many instances favorable market conditions permitted refinancing dollar-denominated obligations into local currency, to reduce overall foreign exchange exposure.

Growth Projects and Building a Pipeline of New Initiatives

Portfolio management, which can include business restructuring and sale of all or a portion of businesses, was an important area of focus and success in 2006. We achieved important milestones in restructuring several of our Brazil businesses through a secondary offering of shares in our Eletropaulo subsidiary and using the proceeds to retire debt that had restrictive covenants precluding dividend payments to be received by AES. We sold a minority share of our Gener subsidiary in Chile, which increased the liquidity of those shares and we believe reduced the discount the local Chile stock market had been placing on Gener shares due to the prior illiquidity. We also sold our 50% equity position in a power project in Canada and sold a power plant in the U.K., both in negotiated transactions. We have worked hard to manage operational and financial risk through appropriate use of interest rate, energy, and foreign exchange risk management instruments and through effective procurement strategies.

We continued to build a robust business development pipeline and extend that pipeline into new areas such as greenhouse gas emission reduction projects and electricity transmission. In the core Generation business, we brought one new power project into service in 2006, a 1,200 MW, $920 million gas-fired power project in Cartagena, Spain (included in Europe & Africa generation). We began construction on a new 670 MW lignite-fired power plant in Bulgaria, supported by a long-term customer contract and included in Europe & Africa generation, and have secured new long-term customer contracts for new projects in Chile, Jordan and Panama. We also entered into purchase agreements to acquire two generation facilities in Mexico, which we consummated in February 2007.

The Company s growth project backlog (growth projects under construction) as of December 31, 2006 totaled over 1,500 gross MW of new generation capacity with total expected investment of approximately $3.2 billion through 2011. This includes fossil-fueled projects in Chile and Bulgaria, a hydroelectric project in Panama, and a wind project in the US. We also secured early-stage memorandums of understanding to develop power projects in countries such as Vietnam, Indonesia, and India.

In addition to the wind project mentioned above, significant 2006 developments in the Company s Alternative Energy business included acquisition of 73 MW of wind generation assets in California and interests in wind project development pipelines totaling approximately 1,360 MW in Scotland (U.K.), France, and Bulgaria. The Company made its first significant strides in the greenhouse gas emission area, acquiring a 9.9% ownership interest in AgCert International (AgCert) for $52 million. AgCert is an Ireland-based company which uses agricultural sources to produce greenhouse gas emission offsets under the Kyoto protocol. AES and AgCert also formed a joint venture, AES AgriVerde, to produce greenhouse gas emission offsets in selected countries in Asia, Europe and North Africa.

The Company expects to fund growth investments from available cash, net cash from operating activities and/or the proceeds from the issuance of debt, common stock, other securities, asset sales, and partner equity contributions. Certain of the Alternative Energy businesses may be considered start-up businesses that will need to be funded internally through cash equity contributions, and may have limited debt financing opportunities initially. We see sufficient attractive investment opportunities that may exceed available cash and net cash from operating activities in future periods.

Critical Accounting Estimates

The consolidated financial statements of AES are prepared in conformity with generally accepted accounting principles in the United States of America, which requires the use of estimates, judgments, and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. AES s significant accounting policies are described in Note 1 to the Consolidated Financial Statements included in Item 8 of this Form 10-K.

An accounting estimate is considered critical if:

- the estimate requires management to make assumptions about matters that were highly uncertain at the time the estimate was made;
- different estimates reasonably could have been used; or
- the impact of the estimates and assumptions on financial condition or operating performance is material.

Management believes that the accounting estimates employed are appropriate and the resulting balances are reasonable; however, actual results could differ from the original estimates, requiring adjustments to these balances in future periods. Listed below are certain significant estimates and assumptions used in the preparation of our consolidated financial statements.

Revenue Recognition

The revenue of the Utilities businesses is classified as regulated on the consolidated statement of operations. Revenues from the sale of energy are recognized in the period in which the energy is delivered. The calculation of revenues earned but not yet billed is based on the number of days not billed in the month, the estimated amount of energy delivered during those days and the estimated average price per customer class for that month. The revenues from the Generation segment are classified as non-regulated and are recorded based upon output delivered and capacity provided at rates as specified under contract terms or prevailing market rates. Revenues from power sales contracts entered into after 1991 with decreasing scheduled rates are recognized based on the output delivered at the lower of the amount billed or the average rate over the contract term.

Allowance for Doubtful Accounts

The Company maintains an allowance for doubtful accounts for estimated uncollectible accounts receivable. The allowance is based on the Company s assessment of known delinquent accounts, historical experience, and other currently available evidence of the collectibility and aging of accounts receivable. There is an increased level of exposure related to the Company s regulated utilities receivables in certain non U.S. locations which are due from local municipalities and other governmental agencies. These customers are often large and normally pay within extended timeframes. The amount of historical experience is limited in some cases due to the recent nature of AES acquisitions subsequent to privatization. In addition, local political and economic factors often play a part in a municipality s current ability or willingness to pay. The Company monitors these situations closely and continues to refine its reserving policy based on both historical experience and current knowledge of the related political/economic environments.

Income Tax Reserves

We are subject to income taxes in both the United States and numerous foreign jurisdictions. Our worldwide income tax provision requires significant judgment and is based on calculations and assumptions that are subject to examination by the Internal Revenue Service and other taxing authorities. The Company and certain of its subsidiaries are under examination by relevant taxing authorities for various tax years. The Company regularly assesses the potential outcome of these examinations in each of the taxing jurisdictions when determining the adequacy of the provision for income taxes. Tax reserves have been established, which the Company believes to be adequate in relation to the potential for additional assessments. Once established, reserves are adjusted only when there is more information available or when an event occurs necessitating a change to the reserves. While the Company believes that the amount of the tax estimates is reasonable, it is possible that the ultimate outcome of current or future examinations may exceed current reserves in amounts that could be material.

Through December 31, 2006 the Company determined its tax liabilities in accordance with SFAS No. 5 *Accounting for Contingencies* (SFAS No. 5). Effective January 1, 2007 the Company adopted the provisions set forth in FIN No. 48 *Accounting for Uncertainty in Income Taxes*. Under FIN No. 48, positions taken on the Company s income tax return which satisfy a more-likely-than-not threshold will be recognized in the financial statements.

Long-Lived Assets

In accordance with SFAS No. 144 *Accounting for the Impairment or Disposal of Long-Lived Assets*, (SFAS No. 144), we periodically review the carrying value of our long-lived assets held and used, other than goodwill and intangible assets with indefinite lives, and assets to be disposed of when circumstances indicate that the carrying amount of such assets may not be recoverable or the assets meet the held for sale criteria under SFAS No. 144. These events or circumstances may include the relative pricing of wholesale electricity by region and the anticipated demand and cost of fuel. If the carrying amount is not recoverable, an impairment charge is recorded for the amount by which the carrying value of the long-lived asset exceeds its fair value. For regulated assets, an impairment charge could be offset by the establishment of a regulatory asset, if rate recovery was probable. For non-regulated assets, an impairment charge would be recorded as a charge against earnings.

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, that is, other than a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for measurement, if available. In the absence of quoted market prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow projections or other indicators of fair value such as bids received, comparable sales or independent appraisals.

In connection with the periodic evaluation of long-lived assets in accordance with the requirements of SFAS No. 144, the fair value of the asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. In cases of impairment described in Note 16 to the Consolidated Financial Statements included in Item 8 of this Form 10-K, we made our best estimate of fair value using valuation methods based on the most current information. We have been in the process of divesting certain assets and their sales values can vary from the recorded fair value as described in Note 19 to the Consolidated Financial Statements included in Item 8 of this Form 10-K. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions, and management s analysis of the benefits of the transaction.

Goodwill

We test goodwill for impairment annually and whenever events or circumstances make it more likely than not that impairment may have occurred, such as a significant adverse change in the business climate or a decision to sell or dispose all or a portion of a business unit. Determining whether an impairment has occurred requires valuation of the respective business unit, which we estimate using a discounted cash flow method. In applying this methodology, we rely on a number of factors, including actual operating results, future business plans, economic projections and market data.

If this analysis indicates goodwill is impaired, measuring the impairment requires a fair value estimate of each identified tangible and intangible asset. In this case, we supplement the cash flow approach discussed above with independent appraisals, as appropriate.

Pension and Other Postretirement Obligations

Certain of our foreign and domestic subsidiaries maintain defined benefit pension plans (the plan) covering substantially all of their respective employees. Pension benefits are generally based on years of credited service, age of the participant and average earnings. The measurement of our pension obligations, costs and liabilities is dependent on a variety of assumptions used by our actuaries. These assumptions include estimates of the present value of projected future pension payments to all plan participants, taking into consideration the likelihood of potential future events such as salary increases and demographic experience. These assumptions may have an effect on the amount and timing of future contributions. The plan actuary conducts an independent valuation of the fair value of pension plan assets.

The assumptions used in developing the required estimates include the following key factors:

- Discount rates;
- Salary growth;
- Retirement rates;
- Inflation;
- Expected return on plan assets; and
- Mortality rates.

The effects of actual results differing from our assumptions are accumulated and amortized over future periods and, therefore, generally affect our recognized expense in such future periods.

Sensitivity of our pension funded status and stockholders equity to the indicated increase or decrease in the discount rate assumption is shown below. Note that these sensitivities may be asymmetric, and are specific to the base conditions at year-end 2006. They also may not be additive, so the impact of changing multiple factors simultaneously cannot be calculated by combining the individual sensitivities shown. The December 31, 2006 funded status is affected by December 31, 2006 assumptions. Pension expense for 2006 is affected by December 31, 2005 assumptions. The impact on pension expense from a one percentage point change in these assumptions is shown in the table below (in millions):

Increase of 1% in the discount rate	$(7)
Decrease of 1% in the discount rate	$22
Increase of 1% in the long-term rate of return on plan assets	$(23)
Decrease of 1% in the long-term rate of return on plan assets	$23

Regulatory Assets and Liabilities

The Company accounts for certain of its regulated operations under the provisions of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation (SFAS No. 71)*. As a result, AES records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred or included in future rate initiatives. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes, recent rate orders applicable to other regulated entities and the status of any pending or potential deregulation legislation. If future recovery of costs ceases to be probable, the asset write-offs would be required to be recognized in operating income.

Accounting for Derivative Instruments and Hedging Activities

We enter into various derivative transactions in order to hedge our exposure to certain market risks. We primarily use derivative instruments to manage our interest rate, commodity, and foreign currency exposures. We do not enter into derivative transactions for trading purposes.

Under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities as amended* (SFAS No. 133), we recognize all derivatives as either assets or liabilities in the balance sheet and measure those instruments at fair value. Changes in fair value of derivatives are recognized in earnings unless specific hedge criteria are met. Income and expense related to derivative instruments are recorded in the same category as generated by the underlying asset or liability.

SFAS No. 133 enables companies to designate qualifying derivatives as hedging instruments based on the exposure being hedged. These hedge designations include fair value hedges and cash flow hedges. Changes in the fair value of a derivative that is highly effective and is designated and qualifies as a fair value hedge, are recognized in earnings as offsets to the changes in fair value of the exposure being hedged. Changes in the fair value of a derivative that is highly effective and is designated as and qualifies as a cash flow hedge, are deferred in accumulated other comprehensive income and are recognized into earnings as the hedged transactions occur. Any ineffectiveness is recognized in earnings immediately. For all hedge contracts, the Company provides formal documentation of the hedge and effectiveness testing in accordance with SFAS No. 133.

As a result of uncertainty, complexity and judgment, accounting estimates related to derivative accounting could result in material changes to our financial statements under different conditions or utilizing different assumptions. As a part of accounting for these derivatives, we make estimates concerning volatilities, market liquidity, future commodity prices, interest rates, credit ratings, and exchange rates.

AES generally uses quoted exchange prices to the extent they are available to determine the fair value of derivatives. In the absence of actively quoted market prices, we seek indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, AES will estimate prices, when possible, based on available historical and near-term future price information as well as utilizing statistical methods. When external valuation models are not available, the company utilizes internal models for valuation. For individual contracts, the use of different valuation models or assumptions could have a material effect on the calculated fair value.

Consolidated Results of Operations

Overview

Results of operations	Year Ended December 31, 2006	2005 Restated	2004 Restated	$ change 2006 vs. 2005	$ change 2005 vs. 2004
	(in millions, except per share data)				
Revenue:					
Latin America Generation	$ 2,616	$ 2,145	$ 1,584	$ 471	$ 561
Latin America Utilities	5,246	4,796	3,824	450	972
North America Generation	1,900	1,809	1,704	91	105
North America Utilities	1,032	951	885	81	66
Europe & Africa Generation	852	735	697	117	38
Europe & Africa Utilities	571	505	463	66	42
Middle East & Asia Generation	840	642	570	198	72
Corporate and Other(1)	(758)	(562)	(335)	(196)	(227)
Total Revenue	$ 12,299	$ 11,021	$ 9,392	$ 1,278	$ 1,629
Gross Margin:					
Latin America Generation	$ 1,054	$ 857	$ 616	$ 197	$ 241
Latin America Utilities	1,071	834	754	237	80
North America Generation	556	590	590	(34)	
North America Utilities	277	301	303	(24)	(2)
Europe & Africa Generation	249	186	182	63	4
Europe & Africa Utilities	112	112	60		52
Middle East & Asia Generation	255	284	252	(29)	32
Total Corporate and Other(2)	(248)	(190)	(147)	(58)	(43)
Interest expense	(1,802)	(1,893)	(1,920)	91	27
Interest income	443	395	283	48	112
Other income	115	171	157	(56)	14
Other expense	(308)	(132)	(123)	(176)	(9)
Gain (loss) on sale of investments	98		(1)	98	1
Loss on sale of subsidiary stock	(539)		(24)	(539)	24
Asset impairment expense	(29)	(16)	(50)	(13)	34
Foreign currency transaction losses on net monetary position	(77)	(101)	(136)	24	35
Equity in earnings of affiliates	72	70	63	2	7
Income tax expense	(403)	(525)	(380)	122	(145)
Minority interest expense	(610)	(369)	(211)	(241)	(158)
Income from continuing operations	286	574	268	(288)	306
(Loss) income from operations of discontinued businesses	(46)	34	32	(80)	2
Extraordinary items	21			21	
Cumulative effect of accounting change		(3)		3	(3)
Net income	$ 261	$ 605	$ 300	$ (344)	$ 305

Per share data:	December 31, 2006	2005 Restated	2004 Restated	$ change 2006 vs. 2005	$ change 2005 vs. 2004
Basic income per share from continuing operations	$ 0.44	$ 0.89	$ 0.42	$ (0.45)	$ 0.47
Diluted income per share from continuing operations	$ 0.43	$ 0.87	$ 0.41	$ (0.44)	$ 0.46

(1) Corporate and Other includes revenues from Alternative Energy and intersegment eliminations of revenues related to transfers of electricity from Tiete (generation) to Eletropaulo (utility).

(2) Total Corporate and Other expenses include corporate general and administrative expenses as well as certain inter-segment eliminations, primarily corporate charges for management fees and self insurance premiums.

Segment Analysis

Latin America

The following table summarizes revenue for our Generation and Utilities segments in Latin America for the periods indicated (in millions):

Latin America	**For the Years Ended December 31,**					
	2006		**2005**		**2004**	
Revenue	**Revenue**	**% of Total Revenue**	**Revenue**	**% of Total Revenue**	**Revenue**	**% of Total Revenue**
Latin America Generation	$ 2,616	21 %	$ 2,145	19 %	$ 1,584	17 %
Latin America Utilities	5,246	43 %	4,796	44 %	3,824	41 %

Fiscal Year 2006 versus 2005 Revenue

Generation revenue increased $471 million, or 22%, due to increased intercompany volume sales and contract energy prices from Tiete to Eletropaulo in Brazil, the acquisition of the controlling shares of Itabo (which resulted in full consolidation of Itabo beginning in June 2006) in the Dominican Republic and an increase in spot market and contract energy prices at Gener in Chile and Alicura and Parana in Argentina.

Utilities revenue increased $450 million, or 9%, due to favorable foreign currency translation impacts, increased demand at EDC in Venezuela from new customers, increased demand at Eletropaulo primarily from increased volume for industrial and commercial customers due to improved economic conditions and increased tariff rates at CAESS/EEO in El Salvador.

Fiscal Year 2005 versus 2004 Revenue

Generation revenue increased $561 million, or 35% due to increased intercompany volume sales and contract energy prices from Tiete to Eletropaulo in Brazil, higher contract energy prices at Gener in Chile and increased volume at Alicura in Argentina and Gener.

Utilities revenue increased $972 million, or 25% due to favorable foreign currency translation impacts, the recognition of a retroactive tariff increase as well as an increase in the average customer tariff due to a rate increase at Eletropaulo in Brazil in 2005.

Fiscal Year 2006 versus 2005 Gross Margin

The following table summarizes gross margin for the Generation and Utilities segments in Latin America for the periods indicated (in millions):

Latin America	**For the Years Ended December 31,**					
	2006		**2005**		**2004**	
Gross Margin	**Gross Margin**	**% of Total Gross Margin**	**Gross Margin**	**% of Total Gross Margin**	**Gross Margin**	**% of Total Gross Margin**
Latin America Generation	$ 1,054	29 %	$ 857	27 %	$ 616	22 %
Latin America Utilities	1,071	29 %	834	26 %	754	27 %

Generation gross margin increased $197 million, or 23%, due to increased intercompany volume sales and contract energy prices from Tiete to Eletropaulo in Brazil, an increase in spot market and contract energy prices at Gener in Chile and the acquisition of the controlling shares of Itabo in the Dominican Republic, partially offset by higher purchased electricity and fuel prices at Uruguaiana in Brazil and higher transmission costs, regulator fees and unfavorable foreign exchange rates at Tiete in Brazil.

Utilities gross margin increased $237 million, or 28%, due to the recording of $192 million of gross bad debts reserve in the second quarter of 2005 related to the collectibility of certain municipal receivables at Eletropaulo and Sul in Brazil, favorable foreign exchange rates in Eletropaulo, a decrease in purchased electricity volume and prices at Eletropaulo, and favorable tariff rates at EDC in Venezuela. The increase in Utilities gross margin was partially offset by the increase for legal reserves at Eletropaulo and certain contingencies at EDC.

Fiscal Year 2005 versus 2004 Gross Margin

Generation gross margin increased $241 million, or 39%, due to higher contract energy prices at Gener in Chile, partially offset by increased purchased electricity and fuel volumes at Andres in the Dominican Republic, unfavorable foreign exchange rates at Gener and Tiete in Brazil and higher transmission costs at Gener.

Utilities gross margin increased $80 million, or 11%, due to higher overall revenues and favorable foreign exchange rates at Eletropaulo in Brazil combined with increased volume at EDC in Venezuela. The increase in Utilities gross margin was partially offset by the recording of $192 million of gross bad debts reserve in the second quarter of 2005 related to the collectibility of certain municipal receivables at Eletropaulo and Sul in Brazil, increased transmissions costs and legal reserves at Eletropaulo.

North America

The following table summarizes revenue for our Generation and Utilities segments in North America for the periods indicated (in millions):

North America	**For the Years Ended December 31,**					
	2006		**2005**		**2004**	
Revenue	**Revenue**	**% of Total Revenue**	**Revenue**	**% of Total Revenue**	**Revenue**	**% of Total Revenue**
North America Generation	$ 1,900	15 %	$ 1,809	16 %	$ 1,704	18 %
North America Utilities	1,032	8 %	951	9 %	885	9 %

Fiscal Year 2006 versus 2005 Revenue

Generation revenue increased $91 million, or 5%, primarily due to higher spot market prices of $75 million in New York, increased charge rates for fuel and variable maintenance costs of $20 million in Puerto Rico, increased tariff rates and volume of $11 million at Deepwater in Texas primarily due to a new contract, a $9 million increase in sales of emission allowances in New York, higher volumes at Thames in Connecticut, and improved operating performance at Southland in California. These increases were partially offset by lower volume and an outage in 2006 at Merida III in Mexico.

Utilities revenue increased $81 million, or 9%, primarily due to higher pricing at IPL in Indiana due to the pass through of higher fuel costs and an increase in costs recovered from a NOx compliance construction program, slightly offset by a decrease in quantity of kWh sold, due to a 20% decrease in the cooling degree days and a 10% decrease in heating degree days compared to 2005.

Fiscal Year 2005 versus 2004 Revenue

Generation revenue increased $105 million, or 6%, primarily due to higher prices of $43 million and an increase in the sale of emission allowances at our business in New York, higher contract prices of $33 million at Merida III in Mexico, higher prices of $24 million in Puerto Rico, and favorable currency impacts of $9 million in Mexico. These increases were partially offset by a decrease in contract price at Shady Point in Oklahoma and outages at Thames in Connecticut.

Utilities revenue increased $66 million, or 7%, primarily due to increase in tariffs and volume at IPL in Indiana. The volume increase was primarily due to a 37% increase in cooling degree days compared to 2004, as well as an increased customer base of approximately 4,300 customers or 1% during 2005.

Fiscal Year 2006 versus 2005 Gross Margin

The following table summarizes gross margin for the Generation and Utilities segments in North America for the periods indicated (in millions):

North America	**For the Years Ended December 31,**					
	2006		**2005**		**2004**	
Gross Margin	**Gross Margin**	**% of Total Gross Margin**	**Gross Margin**	**% of Total Gross Margin**	**Gross Margin**	**% of Total Gross Margin**
North America Generation	$ 556	15 %	$ 590	18 %	$ 590	23 %
North America Utilities	277	8 %	301	9 %	303	11 %

Generation s gross margin decreased $34 million, or 6%, primarily due to outages in 2006 at Warrior Run in Maryland, Hawaii, Ironwood in Pennsylvania and several plants in New York, as well as a scheduled reduction in pricing of the power purchase agreements for our Hawaii plant. The decrease was partly off set by higher energy margins and sales of emission allowances by $9 million in New York and increased contract prices at Deepwater in Texas.

Utilities gross margin decreased $24 million, or 8%, primarily due to higher maintenance costs at IPL in Indiana due to a scheduled outage on one of its large based load coal fired units that coincided with a project to enhance environmental emission technology to significantly reduce emissions as well as increased emissions allowances.

Fiscal Year 2005 versus 2004 Gross Margin

Generation gross margin was flat at $590 million with an increase in sale of emissions allowances in New York of $43 million, an increase in contract prices at Deepwater in Texas and higher volume at Warrior Run in Maryland and our Hawaii plant. These increases were partly offset by a decrease in contract pricing at Shady Point in Oklahoma, outages incurred at Thames in Connecticut, and lower dispatch at Southland in California.

Utilities gross margin decreased $2 million or 1% primarily due to IPL in Indiana having produced a greater portion of their electricity during 2005 using peaking unit resources as a result of higher electricity demand caused by higher average temperatures in the third quarter of 2005 as well as an increase in market price of purchased power.

Europe & Africa

The following table summarizes revenue for the Generation and Utilities segments in Europe & Africa for the periods indicated (in millions):

Europe & Africa	For the Years Ended December 31,					
	2006		2005		2004	
Revenue	Revenue	% of Total Revenue	Revenue	% of Total Revenue	Revenue	% of Total Revenue
Europe/Africa Generation	$ 852	7 %	$ 735	7 %	$ 697	7 %
Europe/Africa Utilities	571	5 %	505	5 %	463	5 %

Fiscal Year 2006 versus 2005 Revenue

Generation revenue increased $117 million, or 16%, primarily due to increased volume sales and contract energy prices at Tisza II in Hungary and at Ekibastuz in Kazakhstan, increased sales in Kazakhstan through our centralized trading office in Altai, and CO_2 emission allowance sales by Tisza II in Hungary and Bohemia in the Czech Republic.

Utilities revenue increased $66 million, or 13%, primarily due to increased demand and tariff rates at Sonel in Cameroon and at our businesses in the Ukraine.

Fiscal Year 2005 versus 2004 Revenue

Generation revenue increased $38 million, or 5%, primarily due to increased volume sales and contract energy prices at both Borsod and Tisza II in Hungary and at Ekibastuz in Kazakhstan and increased sales in Kazakhstan through our centralized trading office in Altai.

Utilities revenue increased $42 million, or 9%. Excluding the impact of foreign currency translation, Utilities revenue increased primarily due to higher volume sales and tariff rates at our businesses in the Ukraine and higher volumes at Sonel in Cameroon.

Fiscal Year 2006 versus 2005 Gross Margin

The following table summarizes gross margin for the Generation and Utilities segments in Europe & Africa for the periods indicated (in millions):

Europe & Africa	For the Years Ended December 31,					
	2006		2005		2004	
Gross Margin	Gross Margin	% of Total Gross Margin	Gross Margin	% of Total Gross Margin	Gross Margin	% of Total Gross Margin
Europe/Africa Generation	$ 249	7 %	$ 186	6 %	$ 182	7 %
Europe/Africa Utilities	112	3 %	112	4 %	60	2 %

Generation gross margin increased $63 million, or 34%, primarily due to higher pricing on improved volumes at Ekibastuz and our centralized trading office Altai, both in Kazakhstan, margin on CO_2 emission allowance sales by Tisza II in Hungary and Bohemia in the Czech Republic.

Utilities gross margin was flat compared to the prior year primarily due to higher expenses at Sonel in Cameroon, offset by improved volume sales and tariff rates for Sonel and our businesses in Ukraine.

Fiscal Year 2005 versus 2004 Gross Margin

Generation gross margin increased $4 million, or 2%, primarily due to higher sales volumes at Tisza II in Hungary, partially offset by increased costs at the Maikuben coal mine in Kazakhstan.

Utilities gross margin increased $52 million, or 87%, primarily due to higher overall revenues, better demand and lower fixed expenses at Sonel in Cameroon.

Asia

The following table summarizes revenue for the Generation segment in Asia for the periods indicated (in millions):

Asia/Middle East	**For the Years Ended December 31,**					
	2006		**2005**		**2004**	
Revenue	**Revenue**	**% of Total Revenue**	**Revenue**	**% of Total Revenue**	**Revenue**	**% of Total Revenue**
Asia/Middle East Generation	$ 840	7 %	$ 642	6 %	$ 570	6 %

Fiscal Year 2006 versus 2005 Revenue

Asia revenues increased $198 million, or 31%, to $840 million in 2006 from $642 million in 2005. Excluding the estimated impacts of foreign currency translation, revenues would have remained constant at 31% from 2005 to 2006. The Asia business consists entirely of Generation revenue. Revenues increased primarily due to increased dispatch of approximately $150 million at the two Pakistan power generation plants, Lal Pir and Pak Gen, as well as $31 million of improvements at Kelanitissa primarily due to favorable dispatch which accounted for $16 million of the increase and increased rates which accounted for $15 million of that increase.

Fiscal Year 2005 versus 2004 Revenue

Asia Generation revenue increased $72 million, or 13%, to $642 million in 2005 from $570 million in 2004. Excluding the estimated impacts of foreign currency translation, revenues would have remained constant at 13% from 2004 to 2005. Revenue increased primarily due to increased volumes at Ras Laffan in Qatar of $35 million; at Kelanitissa in Sri Lanka for $12 million; and at Lal Pir in Pakistan for $8 million.

Fiscal Year 2006 versus 2005 Gross Margin

The following table summarizes gross margin for the Generation segment in Asia for the periods indicated (in millions):

Asia/Middle East	**For the Years Ended December 31,**					
	2006		**2005**		**2004**	
Gross Margin	**Gross Margin**	**% of Total Gross Margin**	**Gross Margin**	**% of Total Gross Margin**	**Gross Margin**	**% of Total Gross Margin**
Asia/Middle East Generation	$ 255	8 %	$ 284	10 %	$ 252	10 %

The gross margin of Asia decreased $29 million, or 10%, to $255 million in 2006 from $284 million in 2005. Gross margins decreased primarily due to a $16.4 million increase in unfavorable variable operating and maintenance costs and $5.5 million of increases associated with a rural grid fund tax.

Fiscal Year 2005 versus 2004 Gross Margin

Gross margin increased $32 million, or 13%, to $284 million in 2005 from $252 million in 2004. Generation gross margin increased $32 million, or 13%, primarily due to improved volume in the Middle East markets of $53 million, which was partially offset by an increase in unfavorable rate variances and depreciation of $17 million and $8 million respectively.

Corporate and Other Expense

Corporate and other expenses include general and administrative expenses related to corporate staff functions and/or initiatives primarily executive management, finance, legal, human resources, information systems and certain development costs which are not allocable to our business segments. In addition, this line item includes net operating results from other businesses which are immaterial for the purposes of separate segment disclosure and,the effects of eliminating transactions, such as management fee arrangements and self-insurance charges, between the operating segments and corporate.

Corporate and other expenses increased $58 million, or 30.5%, to $248 million in 2006 from $190 million 2005. The increase is primarily due to increases in higher corporate development spending primarily in support of our Alternative Energy and Latin American businesses.

Corporate and other expenses increased $43 million, or 29.3%, to $190 million in 2005 from $147 million in 2004. This increase was primarily the result of higher professional and consulting fees associated with the restatement of the company s financial statements as well as increased compensation costs. For both years ended December 31, 2006 and 2005, Corporate and Other were 2% of total revenues.

Interest expense

Interest expense decreased $91 million, or 5%, to $1,802 million in 2006 from $1,893 million in 2005. Interest expense decreased primarily due to the benefits of debt retirements principally in the U.S., Brazil, Venezuela, and the Dominican Republic, lower interest rates at certain of our businesses, and decreased amortization of deferred financing costs, offset by negative impacts from foreign currency translation in Brazil.

Interest expense decreased $27 million, or 1%, to $1,893 million in 2005 from $1,920 million in 2004. Interest expense decreased primarily due to the benefits of debt retirements principally in the U.S. and Venezuela and lower interest rate hedge related costs, offset by negative impacts from foreign currency translation in Brazil.

Interest income

Interest income increased $48 million, or 12%, to $443 million in 2006 from $395 million in 2005. Interest income increased primarily due to favorable foreign currency translation on the Brazilian Real and higher cash and short-term investment balances at certain of our subsidiaries.

Interest income increased $112 million, or 40%, to $395 million in 2005 from $283 million in 2004. Interest income increased primarily due to favorable foreign currency translation on the Brazilian Real and higher cash and short-term investment balances at certain of our subsidiaries combined with higher short-term interest rates.

Other income

	Years Ended December 31, 2006	2005	2004
	(in millions)		
Gain on extinguishment of liabilities	$ 45	$ 82	$ 72
Gain on sale of assets	19	12	14
Insurance proceeds	13	11	
Legal/dispute settlement	1	10	11
Other	37	56	60
Total other income	$ 115	$ 171	$ 157

Other income decreased $56 million to $115 million in 2006 from $171 million in 2005. Other income decreased primarily due to activity at our Brazilian subsidiaries, including the expiration of a tax liability of $70 million and a gain related to the determination of the collectibility of the Sao Paulo municipality agreement in 2005.

Other income increased $14 million to $171 million in 2005 from $157 million in 2004. Other income increased primarily due to the expiration of a tax liability in Brazil during 2005 coupled with gains on liability and debt extinguishments at one of the Company s subsidiaries in Latin America and one in Europe and Africa.

Other expense

	Years Ended December 31, 2006	2005	2004
	(in millions)		
Loss on extinguishment of liabilities	$ (181)	$ (17)	$ (36)
Write-down of disallowed regulatory assets	(36)		
Legal/dispute settlement	(30)	(30)	(5)
Loss on sale and disposal of assets	(28)	(53)	(26)
Marked-to-market loss on commodity derivatives			(5)
Other	(33)	(32)	(51)
Total other expense	$ (308)	$ (132)	$ (123)

Other expense increased $176 million to $308 million in 2006 from $132 million in 2005. Other expense increased primarily due to losses associated with the early extinguishment of debt at several of our Latin American businesses and write-down of disallowed regulatory assets at one of our subsidiaries in Brazil.

Other expense increased $9 million to $132 million in 2005 from $123 million in 2004. Other expense increased primarily due to higher losses on sales and disposals of assets at one of our subsidiaries in Brazil and increased legal settlement costs at the parent company and one of our North American subsidiaries in 2005, offset by higher losses related to equity swap agreements to retire debt at the parent company in 2004.

Asset Impairment Expense

As discussed in Note 17 to the consolidated financial statements, asset impairment expense for the year ended 2006 was $29 million and consisted primarily of the following:

During the fourth quarter of 2006, there was a pre-tax impairment charge of $6 million related to AES China Generating Co. Ltd. (Chigen) equity investment in Wuhu, a coal-fired plant located in China. The equity impairment in Wuhu was required as a result of a goodwill impairment analysis at Chigen. During the second quarter of 2006, there was a pre-tax impairment charge of $11 million related to

AES Ironwood, a gas-fired combined cycle generation plant located in the United States. The fixed asset impairment was caused by a forced outage which was necessary in order to repair a damaged combustion turbine.

Asset impairment expense for the year 2005 was $16 million and consisted primarily of the following:

During the third quarter of 2005, there was a pre-tax impairment charge of $6 million related to Totem Gas Storage, LLC (Totem). The investment asset impairment was due to AES s notification from the sole managing member s intention to dissolve, liquidate, and terminate Totem. This charge, combined with a $1.5 million impairment recognized in the fourth quarter of 2004, represented a complete write-down of AES s investment in Totem. During the first quarter of 2005, there was a pre-tax impairment charge of $5 million related to AES Southland (Southland). The fixed asset impairment was booked when, in the course of evaluating the impairment of long lived assets in accordance with SFAS No. 144, it was determined that the net book value of the peaker units were not fully realizable. During the fourth quarter of 2005, there was an additional pre-tax impairment charge of $2.5 million which represented the remaining carrying value of these units.

Asset impairment expense for the year 2004 was $50 million and consisted primarily of the following:

During the fourth quarter of 2004, there was a pre-tax impairment charge of $15 million related to Aixi, a coal-fired power plant located in China. The investment asset impairment was booked when, in the course of evaluating the impairment of long lived assets in accordance with SFAS No. 144, it was determined that the net book value of this facility was not fully realizable due to circumstances surrounding its operational performance. During the fourth quarter of 2004, there was a pre-tax impairment charge of $25 million related to Deepwater, a petroleum coke-fire cogeneration plant. The investment asset impairment of capitalized costs associated with emission-related improvements was recorded when it was determined that a different strategy would be used to reduce emissions and that the improvements had no alternative uses.

Gain (loss) on sale of investments

Gain on sale of investments was $98 million in 2006 and was primarily comprised of the following:

- In March 2006, we sold our equity investment in a power project in Canada (Kingston) for a net gain of $87 million.

- In September 2006, we transferred Infoenergy, a wholly owned AES subsidiary, to Brasiliana for a net gain of $10 million. Brasiliana is 54% owned by BNDES, but controlled by AES. This transaction was part of the Company s agreement with BNDES to terminate the Sul Option.

There was no gain on sale of investments in 2005 and a $1 million loss on sale of investments in 2004.

Loss on sale of subsidiary stock

As discussed in Note 14 to the Consolidated Financial Statements, in September 2006, Brasiliana s wholly owned subsidiary, Transgás sold a 33% economic ownership in Eletropaulo, a regulated electric utility in Brazil. Despite the reduction in economic ownership, there was no change in Brasiliana s voting interest in Eletropaulo and Brasiliana continues to control Eletropaulo. Brasiliana received $522 million in net proceeds on the sale. On October 5, 2006 Transgás sold an additional 5% economic ownership in Eletropaulo for $80 million. For the twelve months ended December 31, 2006, AES recognized a pre-tax loss of $539 million as a result of the recognition of previously deferred currency translation losses.

In December 2004, an IPO of 35% of the shares of Barka was completed pursuant to the terms of the power and water purchase agreement. For the twelve months ended December 31, 2004, AES recognized a pre-tax loss of $24 million as a result of the sale of Barka shares.

Foreign currency transaction losses on net monetary position

The following table summarizes the losses on the Company s net monetary position from foreign currency transaction activities.

	Years Ended December 31, 2006	2005	2004
	(in millions)		
AES Corporation	$ (17)	$ 10	$ (8)
Argentina	(3)	(5)	(6)
Brazil	(56)	(96)	(58)
Venezuela	12	44	(25)
Dominican Republic		1	(28)
Pakistan	(18)	(22)	(17)
Chile		(20)	(3)
Kazakhstan	1	(4)	14
Columbia	(1)	(5)	(8)
Cameroon	2	(4)	5
Other	3		(2)
Total(1)	$ (77)	$ (101)	$ (136)

(1) Includes $(58) million, $(122) million and $(97) million of losses on foreign currency derivative contracts for December 30, 2006, 2005 and 2004, respectively.

The Company recognized foreign currency transaction losses of $77 million in 2006 compared to losses from foreign currency transactions of $101 million in 2005. The $24 million decrease in losses for 2006 as compared to 2005 was primarily related to lower foreign currency transaction losses in Brazil and Chile offset by lower foreign currency transaction gains in Venezuela and increased foreign currency transaction losses at the parent company. Foreign currency movements typically result from changes in U.S. Dollar exchange rates at subsidiaries whose functional currency is not the U.S. Dollar, as well as gains or losses on monetary assets and liabilities denominated in a currency other than the functional currency of the entity and gains or losses on foreign currency derivatives.

The reduction in foreign currency transaction losses in Brazil is primarily due to a reduction in derivative transaction losses as a result of the reduction in U.S. Dollar denominated debt balances at Eletropaulo partially offset by a decrease in foreign currency transaction gains associated with U.S. Dollar denominated debt balances as the Brazilian Real appreciated 13% in 2006 as compared to 2005. The reduction in foreign currency transaction losses in Chile is primarily due to the devaluation of the Chilean Peso by 4% in 2006 versus 2005, resulting in decreased losses on foreign currency derivative contracts at Gener.

The reduction in foreign currency transaction gains in Venezuela is primarily due to the 11% devaluation of the Venezuelan Bolivar in 2005 compared to minimal change in 2006. When the Venezuelan Bolivar devalues, gains are recognized related to the remeasurement of Bolivar denominated monetary liabilities, including debt. Thus, lower foreign currency transaction gains of $12 million were realized in 2006 versus $44 million in 2005 as a result of minimal change of the Bolivar in 2006.

The Company recognized foreign currency transaction losses of $101 million in 2005 compared to losses from foreign currency transactions of $136 million in 2004. The $35 million decrease in losses for 2005 as compared to 2004 was primarily related to the gains in Venezuela and the Dominican Republic partially offset by losses in Brazil and Chile. Foreign currency transaction losses decreased primarily due to lower annual devaluation in 2005 of the Venezuelan Bolivar of 10.7% compared to 16.7% in 2004 contributing to $69 million of the change over the year. The Dominican Peso devalued 11.3% in 2005 as compared to a 31.2% appreciation in 2004 contributing to $29 million of the change year over year partially related to one of our Dominican businesses which has a net monetary liability position denominated in the Dominican Peso. The Brazilian Real appreciated 11.7% during 2005 compared to 7.5% in 2004 offsetting the overall decrease in foreign currency losses by $38 million. The Chilean Peso appreciated 15.9% during 2005 compared to no change in 2004. The appreciation of the Chilean Peso increased losses of foreign currency derivative contracts in our Chilean businesses offsetting the overall decrease in foreign currency losses by $17 million.

Equity in earnings of affiliates

Equity in earnings of affiliates increased $2 million, or 3%, to $72 million in 2006 from $70 million in 2005. The increase was primarily due to the settlement of a legal claim in 2006 related to AES Barry, an equity method investment of AES during the first quarter of 2006, and higher earnings at several affiliates in Latin America. The increase was offset by the impact of increased losses at Cartagena, an equity method investment in Spain, in 2006 as compared to 2005.

Equity in earnings of affiliates increased $7 million, or 11%, to $70 million in 2005 from $63 million in 2004. The increase was primarily due to a plant fire causing lower earnings in 2004 at our affiliate in Canada, improved operations from our affiliates in India and the Netherlands, partially offset by reduced earnings due to higher coal prices at our affiliates in China.

Income taxes

Income tax expense related to continuing operations decreased $122 million to $403 million in 2006 from $525 million in 2005. The Company s effective tax rates were 31% for 2006 and 36% for 2005. The reduction in the 2006 effective tax rate was due, in part, to the second quarter 2006 release of a $43 million valuation allowance at the Company s Brazilian subsidiary, Eletropaulo, related to its deferred tax assets on certain pension obligations, a decrease in U.S. taxes on distributions from certain non-U.S. subsidiaries due to recent changes in tax laws, and the sale of Kingston in the first quarter of 2006, the gain on which was not taxable.

Income tax expense related to continuing operations increased $145 million to $525 million in 2005 from $380 million in 2004. The Company s effective tax rates were 36% for 2005 and 44% for 2004. The reduction in the 2005 effective tax rate was due, in part, to the reduction of taxes imposed on earnings of and distributions from the Company s foreign subsidiaries and adjustments derived from the Company s 2004 income tax returns filed in 2005.

Minority interest

Minority interest expense, net of tax, increased $241 million to $610 million in 2006 from $369 million in 2005. The increase is primarily due to higher earnings from our Brazilian companies offset by a decrease in the third quarter of 2006 in our economic ownership in Eletropaulo from 34% to 16%. We entered into a series of transactions to sell a portion of our shares in Eletropaulo as part of the restructuring of Brasiliana. See Note 14 to the Consolidated Financial Statements for a further discussion of the sale of Eletropaulo shares and Brasiliana restructuring.

Minority interest expense, net of tax, increased $158 million to $369 million in 2005 from $211 million in 2004. The increase is primarily due to higher earnings from our subsidiaries in Brazil and Cameroon and the 2004 sale of our interest in Oasis.

Discontinued operations

As discussed in Note 20 to the consolidated financial statements included in Item 8 of this Form 10-K; during 2006 we discontinued certain of our operations including Eden, a regulated utility located in Argentina, AES Indian Queens Power Limited and AES Indian Queens Operations Limited, collectively

IQP , which is an Open Cycle Gas Turbine, located in the U.K. Income from operations of discontinued businesses, net of tax, was $11 million in 2006.

In May 2006, the Company reached an agreement to sell 100% of its interest in Eden. Governmental approval of the transaction is still pending in Argentina, but the Company has determined that the sale is probable at this time. Therefore, Eden, a wholly-owned subsidiary of AES, has been classified as held for sale and reflected as such on the face of the financial statements. The Company recognized a $62 million impairment charge to adjust the carrying value of Eden s assets to their estimated net realizable value. The impairment expense is included in the 2006 loss from disposal of discontinued businesses line item on the financial statements.

In September 2006, the Company completed the sale of IQP. Proceeds from the sale were $28 million in cash and the buyer s assumption of debt of $30 million. The Company recognized a gain on disposal of discontinued businesses of $5 million. The results of operations of IQP and the associated gain on disposal are reflected in the discontinued operations line items on the financial statements.

In 2005, income from operations of discontinued businesses, net of tax, was $34 million. Income from operations of Eden and IQP totaled approximately $3 million for 2005. Additionally, a reversal of approximately $31 million was recorded in the third quarter of 2005 at Eden, related to the release of valuation allowance previously recorded against its net deferred tax assets.

Loss from operations of discontinued businesses, net of tax, was $59 million in 2004. This loss was offset by a gain on disposal of discontinued businesses of $91 million during the year. Businesses sold during 2004 included Whitefield, AES Communications Bolivia, Colombia I, Ede Este, Wolf Hollow, Carbones Internacionales del Cesar S.A. and Granite Ridge. These entities were recorded in discontinued operations in prior years.

Extraordinary item

As discussed in Note 6 to the Consolidated Financial Statements included in Item 8 of this Form 10-K, in May 2006, AES purchased an additional 25% interest in Itabo, a power generation business located in the Dominican Republic for approximately $23 million. Prior to May, the Company held a 25% interest in Itabo, through its Gener subsidiary, and had accounted for the investment using the equity method of accounting with a corresponding investment balance reflected in the Investments in and advances to affiliates line item on the consolidated balance sheets. As a result of the transaction, the Company consolidates Itabo and, therefore, the investment balance has been reclassified to the appropriate line items on the consolidated balance sheets with a corresponding minority interest liability for the remaining 50% interest not owned by AES. The Company realized an after-tax extraordinary gain of $21 million as a result of the transaction due to an excess of the fair value of the noncurrent assets over the purchase price.

Capital Resources And Liquidity

Overview

We are a holding company that conducts all of our operations through subsidiaries. We have, to the extent achievable, utilized non-recourse debt to fund a significant portion of the capital expenditures and investments required to construct and acquire our electric power plants, distribution companies and related assets. This type of financing is non-recourse to other subsidiaries and affiliates and to us (as the parent company), and is generally secured by the capital stock, physical assets, contracts and cash flow of the related subsidiary or affiliate. At December 31, 2006, we had $4.8 billion of recourse debt and $11.6 billion of non-recourse debt outstanding. For more information on our long-term debt see Note 8 to the Consolidated Financial Statements included in Item 8 of this Form 10-K.

In addition to the non-recourse debt, if available, we, as the parent company, provide a portion, or in certain instances all, of the remaining long-term financing or credit required to fund development, construction or acquisition. These investments have generally taken the form of equity investments or loans, which are subordinated to the project s non-recourse loans. We generally obtain the funds for these investments from our cash flows from operations and/or the proceeds from our issuances of debt, common stock, and other securities as well as proceeds from the sales of assets. For example in March 2006, AES sold its interest in Kingston for $110 million. Similarly, in certain of our businesses, we may provide financial guarantees or other credit support for the benefit of lenders or counterparties who have entered into contracts for the purchase or sale of electricity with our subsidiaries. In such circumstances, if a subsidiary defaults on its payment or supply obligation, we will be responsible for the subsidiary s obligations up to the amount provided for in the relevant guarantee or other credit support.

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

As a result of AES parent s below-investment-grade rating, counter-parties may be unwilling to accept our general unsecured commitments to provide credit support. Accordingly, with respect to both new and existing commitments, we may be required to provide some other form of assurance, such as a letter of credit, to backstop or replace our credit support. We may not be able to provide adequate assurances to such counterparties. In addition, to the extent we are required and able to provide letters of credit or other collateral to such counterparties, this will reduce the amount of credit available to us to meet our other liquidity needs. At December 31, 2006, we had provided outstanding financial and performance related guarantees or other credit support commitments to or for the benefit of our subsidiaries, which were limited by the terms of the agreements, in an aggregate of approximately $995 million (including those collateralized by letters of credit and other obligations discussed below). Management believes that cash on hand, along with cash generated through operations, and our financing availability will be sufficient to fund normal operations, capital expenditures, and debt service requirements.

At December 31, 2006, we had $461 million in letters of credit outstanding, which operate to guarantee performance relating to certain project construction and development activities and subsidiary operations. All of these letters of credit were provided under our revolving credit facility and senior unsecured credit facility. We pay letter of credit fees ranging from 1.63% to 2.64% per annum on the outstanding amounts. In addition, we had $1 million in surety bonds outstanding at December 31, 2006.

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

Capital Expenditures

The Company spent $1.5 billion, $0.8 billion and $0.7 billion on capital expenditures in 2006, 2005 and 2004, respectively. We anticipate capital expenditures during 2007 to approximate between $2.3 to $2.5 billion excluding EDC, our former Venezuelan business. Planned capital expenditures include new project construction costs, environmental pollution control construction and expenditures for existing assets to increase their useful lives. Capital expenditures for 2007 are expected to be financed using internally generated cash provided by operations and project level financing and possibly debt or equity financing at the AES parent company level.

Cash Flows

				Favorable/(Unfavorable)	
Years Ended December 31, (in millions)	**2006**	**2005**	**2004**	**06 vs. 05**	**05 vs. 04**
Operating	$ 2,411	$ 2,154	$ 1,608	$ 257	$ 546
Investing	(902)	(661)	(743)	(241)	82
Financing	(1,317)	(1,339)	(1,285)	22	(54)

At December 31, 2006 we increased cash and cash equivalents by $254 million from December 31, 2005 to a total of $1,575 million. The change in cash balances was impacted by $2,411 million of cash provided by operating activities offset by a use of cash for investing and financing of $902 million and $1,317 million, respectively and the positive effect of foreign currency translation of cash balances of $62 million.

Operating Activities

Net cash provided by operating activities increased by $257 million to $2,411 million during 2006 compared to $2,154 million during 2005. This increase was primarily due to:

- $552 million increase in net earnings (adjusted for non cash items) and,
- $43 million of certain settlement proceeds, partially offset by,
- $211 million increase in cash taxes paid predominately by our Brazilian subsidiaries,
- higher long term compensation payments, and
- one-time cash inflow of $49 million received in the first quarter of 2005 by EDC, our Venezuelan subsidiary, related to a cancelled foreign exchange derivative instrument.

The $895 million increase in adjustments to net income was primarily due to the reversal of non-cash adjustments for:

- a $470 million loss on the sale by Transgas of Eletropaulo shares;
- $147 million increased losses on debt extinguishment;
- an increase in minority interest expense of $238 million;
- $183 million higher reserves for various liabilities, including litigation adjustments for various Brazilian subsidiaries; partially offset by,
- $172 million decrease in the provision for deferred taxes; and
- $41 million increased earnings of affiliates.

The following table includes details of changes in operating assets and liabilities on the face of the Consolidated Statement of Cash Flows:

	2006	2005	Change
	(in millions)		
Decrease (increase) in accounts receivable	$ 84	$ (29)	$ 113
Increase in inventory	(24)	(70)	46
Decrease in prepaid expenses and other current assets	8	94	(86)
Decrease in other assets	165	84	81
Decrease in accounts payable and accrued liabilities	(400)	(119)	(281)
(Decrease) increase in other liabilities	(122)	45	(167)
Total	$ (289)	$ 5	$ (294)

Accounts receivable decreased in the current year primarily due to lower energy pricing at our New York plant.

Inventory increased in the current year primarily due to seasonal increases and higher coal pricing at New York and IPL as well as an increase in copper pricing at EDC which is used for cabling.

Other assets decreased in the current year due to a decrease in regulatory assets at Eletropaulo as a result of the recovery of energy related costs and a decrease in a long term receivable due from the Government of Cameroon, SONEL s largest customer. These decreases were offset by an increase in long term customer receivables at Eletropaulo and a prepayment of an insurance premium at Maritza, in Bulgaria.

Accounts payable and other current liabilities declined in the current year mainly due to the release of the SUL option, a decrease in accrued interest due to debt restructuring at Brasiliana and Eletropaulo and a decrease in swap payments due to lower energy pricing at New York.

Other liabilities decreased in the current year primarily due to the decrease in pension liabilities at Eletropaulo, IPL, Sul, and EDC.

Investing Activities

Net cash used in 2006 for investing activities totaled $902 million compared to $661 million for 2005, an increase of $241 million. This increase was primarily attributable to the following:

Capital expenditures increased $634 million to $1,460 million during 2006 compared to 2005 mainly due to increased spending of $245 million for the Maritza East 1 lignite-fired power plant in Bulgaria, $161 million for wind development projects at Buffalo Gap 2 in the U.S., $83 million primarily for pollution control technology projects at IPL in the U.S., $41 million primarily for the Greenidge and Westover clean coal projects at New York in the U.S., $37 million at EDC in Venezuela and $33 million at Sul in Brazil.

Acquisitions-net of cash acquired totaled $19 million in 2006 and $85 million in 2005, a $66 million reduction over 2005. This included $13 million to acquire an additional 25% of Itabo in the Dominican Republic and approximately $5 million to acquire the remaining shares in Alicura located in Argentina. The $85 million spent in the prior year related to our wind development businesses: the purchase of SeaWest s net assets and pre-construction costs for Buffalo Gap. Both operations are located in the U.S.

Proceeds from the sale of businesses totaled $898 million in 2006 and $22 million in 2005, an increase of $876 million. The sales included $522 million from the sale by Transgas of Eletropaulo preferred shares and $80 million in a related sale by Brasiliana of its preferred shares in Eletropaulo, $123 million from the sale of approximately 7.6% of our shares in AES Gener, $110 million from the sale of our Kingston business in Canada, $33 million from the sale of unissued shares at EDC and $28 million from the sale of

Indian Queens. The proceeds in 2005 included the sale of a minority interest in Barka Holdings, Ltd. for $22 million.

The purchase of short-term investments, net of sales, increased $502 million during 2006 as compared to the same period in 2005. These transactions included a $255 million increase in net purchases at Tiete in Brazil due to a change in investment strategy from investing in cash equivalents to Brazilian government bonds, a $158 million decrease in the net sale of investments at EDC due to the release of a collateral deposit on local debt, a $70 million increase in net purchases at Eletropaulo in Brazil, funded by the redemption of financial treasury bills and a $30 million increase in net purchases at Gener as the result of additional time deposits acquired.

Restricted cash balances in 2006 increased $102 million over 2005 balances. This change was comprised of the following increases: $59 million at Ras Laffan in Qatar, $31 million at IPL, $30 million at Kilroot in the United Kingdom, $26 million at Southland in the U.S. and $17 million at Parana in Argentina. These increases were offset by decreases of $44 million at New York, $26 million at Eletropaulo in Brazil and $26 million at Panama.

Proceeds from the sales of emission allowances totaled $82 million in 2006, a $40 million increase over 2005. Purchases of emission allowances totaled $77 million in 2006, a $58 million increase over 2005. These sales and purchases occurred primarily by businesses located in the U.S. and Europe. Included in the purchases during 2006 was a $45 million commitment to purchase Certified Emission Reduction (CER) credits from AgCert International (AgCert). AgCert is an alternative energy, Ireland-based company which uses agricultural sources to produce greenhouse gas emission offsets under the Kyoto protocol.

Debt service reserves and other assets totaled $46 million in 2006, a $146 million decrease over the balance in 2005. This was mainly due to decreases of $45 million at Tiete, $42 million at EDC, $22 million at Eletropaulo, $21 million at Ebute in Nigeria, $13 million at Panama, $10 million at Southland and $8 million at Sonel in Africa. These decreases were offset by an increase at Ironwood for $17 million and at Hawaii for $11 million, both located in the U.S.

Purchases of long-term available-for-sale securities includes $52 million related to an investment in AgCert in 2006.

Financing Activities

Net cash used in financing activities decreased by $22 million to $1,317 million during 2006 compared to $1,339 million during 2005. This change was attributable to a decrease in debt, net of issuances of $102 million an increase in contributions from minority interests of $124 million and an increase due to issuance of common stock of $52 million offset by an increase in distributions to minority interests of $149 million, an increase in payments for deferred financing of $65 million and an increase in payments for financed capital expenditures of $51 million.

Debt issuances of recourse debt, non-recourse debt and revolving credit facilities, net during 2006 were $3,169 million compared to $1,768 million during 2005. This increase of $1,401 million was due to an increase in borrowings at Brasiliana in Brazil of $744 million, at Maritza in Bulgaria of $240 million, at Itabo in the Dominican Republic of $177 million, at Buffalo Gap 2 in the U.S. of $116 million and at Lal Pir in Pakistan of $64 million. In addition, there were refinancings at Sul in Brazil for $476 million, at Panama for $287 million and at IPL in the U.S. for $156 million as well as bond issuances at CAESS for $207 million and at CLESA for $77 million, both located in El Salvador. These increases were offset by a decrease in borrowings at Eletropaulo in Brazil of $618 million, at Andres in the Dominican Republic of $160 million, at EDC in Venezuela of $141 million, at Wind in the U.S. of $110 million and at Tiete in Brazil of $80 million. There was also a decrease in refinancing at Gener in Chile for $31 million.

Debt repayments during 2006 were $4,209 million compared to $2,910 million during 2005. The increase of $1,299 million was primarily due to repayments at Brasiliana for $1,032 million, at Sul for $446 million, at Panama for $281 million, at Tiete for $274 million, at CAESS for $175 million, at IPL for $130 million, at Buffalo Gap for $116 million, at Lal Pir for $57 million and at CLESA for $55 million. This increase was offset by a decrease in repayments at Eletropaulo of $594 million, at EDC of $408 million, at Andres of $112 million, at the parent of $108 million and at Gener of $58 million.

Minority contributions during 2006 were $125 million compared to $1 million during 2005. This resulted in an increase of $124 million primarily due to Buffalo Gap in the U.S., which received a contribution from their tax equity partners of $117 million. Minority distributions were $335 million compared to $186 million during 2005. This increase of $149 million was primarily due to Tiete, which paid minority dividends of $170 million during 2006 compared to $66 million in 2005.

Payments for deferred financing costs during 2006 were $86 million compared to $21 million during 2005. The $65 million increase in payments was primarily due to new financing at Maritza and refinancing at Sul.

Financed capital expenditures increased $51 million during 2006 predominately at Buffalo Gap where we financed these acquisitions by paying for them over a period greater than three months.

Contractual Obligations

A summary of our contractual obligations, commitments and other liabilities as of December 31, 2006 is presented in the table below (in millions).

Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**	**Footnote Reference**
Debt Obligations(1)	$ 16,345	$ 1,453	$ 2,639	$ 3,127	$ 9,126	8
Interest Payments on Long-Term Debt(2)	9,819	1,394	2,517	2,012	3,896	n/a
Capital Lease Obligations(3)	10	4	5	1		10
Other Long-term Liabilities Reflected on AES s Consolidated Balance Sheet under GAAP(4)	892	85	180	152	475	n/a
Operating Lease Obligations(5)	178	17	30	22	109	10
Sale Leaseback Obligations(6)	1,316	63	126	134	993	10
Electricity Obligations(7)	23,389	1,430	3,204	3,568	15,187	10
Fuel Obligations(8)	10,509	1,020	1,902	1,554	6,033	10
Other(9)	3,374	1,234	1,058	263	819	10
Total	$ 65,832	$ 6,700	$ 11,661	$ 10,833	$ 36,638	

(1) Includes non-recourse debt and recourse debt presented on our consolidated financial statements. Non-recourse debt borrowings are not a direct obligation of AES, the parent company, and are primarily collateralized by the capital stock of the relevant subsidiary and in certain cases the physical assets of, and all significant agreements associated with, such subsidiaries. These non-recourse financings include structured project financings, acquisition financing, working capital facilities and all other consolidated debt of the subsidiaries. Recourse debt borrowings are the borrowings of AES, the parent company. Note 8 to the Consolidated Financial Statements included in Item 8 of this Form 10-K provides disclosure of these obligations.

(2) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2006 and do not reflect anticipated future refinancing, early redemptions, new debt issuances or certain interest on liabilities other than debt. Variable rate interest obligations are estimated based on rates as of December 31, 2006.

(3) Several AES subsidiaries lease operating and office equipment and vehicles. These leases have been recorded as capital leases in Property, Plant and Equipment within Electric Generation and Distribution Assets. Minimum contractual obligations include $2 million of imputed interest.

(4) Other Long-Term Liabilities reflected on AES s consolidated balance sheet under GAAP include only those amounts that are contractual obligations. These amounts do not include (1) current liabilities on the consolidated balance sheet, (2) any taxes or regulatory liabilities, (3) contingencies, (4) pension and other post retirement employee benefit liabilities (see Note 12 to the Consolidated Financial Statements included in Item 8 of this Form 10-K).

(5) As of December 31, 2006, the Company was obligated under long-term non-cancelable operating leases, primarily for office rental and site leases. These amounts exclude amounts related to the sale/leaseback discussed below in item (6).

(6) Sale/Leaseback Obligations - In May 1999, a subsidiary of the Company acquired six electric generating stations from New York State Electric and Gas (NYSEG). Concurrently, the subsidiary sold two of the plants to an unrelated third party for $666 million and simultaneously entered into a leasing arrangement with the unrelated party. This transaction has been accounted for as a sale/leaseback with operating lease treatment.

(7) **Operating** subsidiaries of the Company have entered into contracts for the purchase of electricity from third parties.

(8) Fuel Obligations - Operating subsidiaries of the Company have entered into various contracts for the purchase of fuel subject to termination only in certain limited circumstances.

(9) Amounts relate to other contractual obligations where the Company has an agreement to purchase goods or services that is enforceable and legally binding on the Company that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. These amounts exclude planned capital expenditures that are not contractually obligated.

Parent Company Liquidity

Because of the non-recourse nature of most of our indebtedness, The AES Corporation believes that unconsolidated parent company liquidity is an important measure of liquidity. Our principal sources of liquidity at the parent company level are:

- dividends and other distributions from our subsidiaries, including refinancing proceeds;
- proceeds from debt and equity financings at the parent company level, including borrowings under our credit facilities; and
- proceeds from asset sales

Our cash requirements at the parent company level are primarily to fund:

- interest and preferred dividends;
- principal repayments of debt;
- acquisitions;

- construction commitments;
- other equity commitments;

- taxes; and
- parent company overhead and development costs.

Since 2002, The AES Corporation has undertaken various initiatives to improve the credit and risk profile of both the parent and the consolidated company while continuing to pursue disciplined growth.

On March 3, 2006, The AES Corporation redeemed all of its outstanding 8.875% Senior Subordinated Debentures due 2027 (approximately $115 million aggregate principal amount). The redemption was made pursuant to the optional redemption provisions of the indenture governing the Debentures. The Debentures were redeemed at a redemption price equal to 100% of the principal amount thereof, plus a make-whole premium determined in accordance with the terms of the indenture, plus accrued and unpaid interest up to the redemption date.

In December 2006, The AES Corporation exercised its right to increase the revolving credit facility by $100 million to a total of $750 million. As of December 31, 2006, there were no outstanding borrowings against the revolving credit facility. We had $88 million of letters of credit outstanding against the revolving credit facility and $662 million available under the revolving credit facility as of December 31, 2006.

The AES Corporation entered into a $500 million senior unsecured credit facility agreement effective March 31, 2006. On May 1, 2006, The AES Corporation exercised its option to extend the total amount of the senior unsecured credit facility by an additional $100 million to a total of $600 million. At December 31, 2006, the Company had no outstanding borrowings under the senior unsecured credit facility. The AES Corporation had $373 million of letters of credit outstanding against the senior unsecured credit facility as of December 31, 2006. The credit facility is being used to support our ongoing share of construction obligations for AES Maritza East 1 and for general corporate purposes.

The following table sets forth parent company liquidity as of December 31, for the periods indicated.

Parent Company Liquidity	**2006**	**2005**	**2004**
	(in millions)		
Cash and cash equivalents	$ 1,575	$ 1,321	$ 1,154
Less: Cash and cash equivalents at subsidiaries	1,338	1,059	867
Parent cash and cash equivalents	237	262	287
Borrowing available under revolving credit facility	662	356	352
Borrowing available under senior unsecured credit facility	227		
Cash at qualified holding companies	20	6	4
Total parent liquidity	$ 1,146	$ 624	$ 643

Our parent recourse debt at year-end was approximately $4.8 billion, $4.9 billion, and $5.2 billion in 2006, 2005 and 2004, respectively. Our contingent contractual obligations were $995 million, $802 million, and $559 million at the end of 2006, 2005, and 2004, respectively.

The following table sets forth our parent company contingent contractual obligations as of December 31, 2006:

Contingent Contractual obligations	**Amount (in millions)**	**Number of Agreements**	**Exposure Range for Each Agreement**
Guarantees	$ 533	$ 32	<$1 - $100
Letters of credit under the revolving credit facility	88	12	<$1 - $26
Letters of credit under the senior unsecured credit facility	373	8	<$1 - $333
Surety bonds	1	1	<$1
Total	$ 995	$ 53	

We have a varied portfolio of performance related contingent contractual obligations. These obligations are designed to cover potential risks and only require payment if certain targets are not met or certain contingencies occur. The risks associated with these obligations include change of control, construction cost overruns, subsidiary default, political risk, tax indemnities, spot market power prices, supplies support and liquidated damages under power sales agreements for projects in development, under construction and operating. While we do not expect that we will be required to fund any material amounts under these contingent contractual obligations during 2007 or beyond, many of the events which would give rise to such an obligations are beyond our control. We can provide no assurance that we will be able to fund our obligations under these contingent contractual obligations if we are required to make substantial payments thereunder.

While we believe that our sources of liquidity will be adequate to meet our needs through the end of 2007, this belief is based on a number of material assumptions, including, without limitation, assumptions about our ability to access the capital markets, the operating and financial performance of our subsidiaries, exchange rates, power market pool prices, and the ability of our subsidiaries to pay dividends. In addition, our subsidiaries ability to declare and pay cash dividends to us (at the parent company level) is subject to certain limitations contained in loans, governmental provisions and other agreements. We can provide no assurance that these sources will be available when needed or that our actual cash requirements will not be greater than anticipated. We have met our interim needs for shorter-term and working capital financing at the parent company level with our revolving credit facility and senior unsecured credit facility. See Item 1A. Risk Factors The AES Corporation is a holding company and its ability to make payments on its outstanding indebtedness, including its public debt securities, is dependent upon the receipt of funds from its subsidiaries by way of dividends, fees, interest, loans or otherwise

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

- limitations on other indebtedness, liens, investments and guarantees;
- restrictions on dividends and redemptions and payments of unsecured and subordinated debt and the use of proceeds;
- restrictions on mergers and acquisitions, sales of assets, leases, transactions with affiliates and off balance sheet and derivative arrangements;
- maintenance of certain financial ratios; and
- financial and other reporting requirements.

Non-Recourse Debt Financing

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

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

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

Some of our subsidiaries are currently in default with respect to all or a portion of their outstanding indebtedness. The total debt classified as current in the accompanying consolidated balance sheets related to such defaults was $245 million at December 31, 2006, all of which is non-recourse debt.

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

Off-Balance Sheet Arrangements

In May 1999, one of our subsidiaries acquired six electric generating plants from New York State Electric and Gas. Concurrently, the subsidiary sold two of the plants to an unrelated third party for $666 million and simultaneously entered into a leasing arrangement with the unrelated party. We have accounted for this transaction as a sale/leaseback transaction with operating lease treatment. Accordingly, we have not recorded these assets on our books and we expense periodic lease payments, which amounted to $54 million in 2005, as incurred. The lease obligations bear an imputed interest rate of approximately 9% which approximates fair market value. We are not subject to any additional liabilities or contingencies if the arrangement terminates, and we believe that the dissolution of the off-balance sheet arrangement would have minimal effects on our operating cash flows. The terms of the lease include restrictive covenants such as the maintenance of certain coverage ratios. Historically, the plants have satisfied the restrictive covenants of the lease, and there are no known trends or uncertainties that would indicate that the lease will be terminated early. See Note 10 to the Consolidated Financial Statements included in Item 8 of this Form 10-K for a more complete discussion of this transaction.

IPL, a subsidiary of the Company, formed IPL Funding Corporation (IPL Funding) in 1996 as a special-purpose entity to purchase retail receivables originated by IPL pursuant to a receivables sale agreement entered into with IPL. At the same time, IPL Funding entered into a purchase facility (the Purchase Facility) with unrelated parties (the Purchasers) pursuant to which the Purchasers agree to purchase from IPL Funding, on a revolving basis, up to $50 million, of interests in the pool of receivables purchased from IPL. As collections reduce accounts receivable included in the pool, IPL Funding sells ownership interests in additional receivables acquired from IPL to return the ownership interests sold up to a maximum of $50 million, as permitted by the Purchase Facility. During 2006, the Purchase Facility was extended through May 29, 2007. IPL Funding is included in the consolidated financial statements of IPL. Accounts receivable on the accompanying consolidated balance sheets of IPALCO are stated net of the $50 million sold.

IPL retains servicing responsibilities for its role as a collection agent on the amounts due on the sold receivables. However, the Purchasers assume the risk of collection on the purchased receivables without recourse to IPL in the event of a loss. While no direct recourse to IPL exists, it risks loss in the event collections are not sufficient to allow for full recovery of its retained interests. No servicing asset or liability is recorded since the servicing fee paid to IPL approximates a market rate.

The carrying values of the retained interest is determined by allocating the carrying value of the receivables between the assets sold and the interests retained based on relative fair value. The key assumptions in estimating fair value are credit losses, the selection of discount rates, and expected receivables turnover rate. As a result of short accounts receivable turnover period and historically low credit losses, the impact of these assumptions have not been significant to the fair value. The hypothetical effect on the fair value of the retained interests assuming both a 10% and a 20% unfavorable variation in credit losses or discount rates is not material due to the short turnover of receivables and historically low credit loss history.

The losses recognized on the sales of receivables were $3 million, $2 million and $1 million for 2006, 2005 and 2004, respectively. These losses are included in Other operating expense on the consolidated statements of income. The amount of the losses recognized depends on the previous carrying amount of the financial assets involved in the transfer, allocated between the assets sold and the interests that continue to be held by the transferor based on their relative fair value at the date of transfer, and the proceeds received.

There are no proceeds from new securitizations for each of 2006, 2005 and 2004. Servicing fees of $0.6 million were paid for each of 2006, 2005 and 2004.

IPL and IPL Funding provide certain indemnities to the Purchasers, including indemnification in the event that there is a breach of representations and warranties made with respect to the purchased receivables. IPL Funding and IPL each have agreed to indemnify the Purchasers on an after-tax basis for any and all damages, losses, claims, liabilities, penalties, taxes, costs and expenses at any time imposed on or incurred by the indemnified parties arising out of or otherwise relating to the purchase facility, subject to certain limitations as defined in the Purchase Facility.

Under the Purchase Facility, if IPL fails to maintain certain financial covenants regarding interest coverage and debt-to-capital ratios, it would constitute a termination event. As of December 31, 2006, IPL was in compliance with such covenants.

As a result of IPL s current credit rating, the facility agent has the ability to (i) replace IPL as the collection agent; and (ii) declare a lock-box event. Under a lock-box event or a termination event, the facility agent has the ability to require all proceeds of purchased receivables of IPL to be directed to lock-box accounts within 45 days of notifying IPL. A termination event would also (i) give the facility agent the option to take control of the lock-box account, and (ii) give the Purchasers the option to discontinue the purchase of additional interests in receivables and cause all proceeds of the purchased interests to be used to reduce the Purchaser s investment and to pay other amounts owed to the Purchasers and the facility agent. This would have the effect of reducing the operating capital available to IPL by the aggregate amount of such purchased interests in receivables (currently $50 million).

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Overview Regarding Market Risks

We are exposed to market risks associated with interest rates, foreign exchange rates and commodity prices. We often utilize financial instruments and other contracts to hedge against such fluctuations. We also utilize financial and commodity derivatives for the purpose of hedging exposures to market risk. We generally do not enter into derivative instruments for trading or speculative purposes.

Interest Rate Risks

We are exposed to risk resulting from changes in interest rates as a result of our issuance of variable-rate debt, fixed-rate debt and trust preferred securities, as well as interest rate swap and option agreements. Depending on whether a plant s capacity payments or revenue stream is fixed or varies with inflation, we partially hedge against interest rate fluctuations by arranging fixed-rate or variable-rate financing. In certain cases, we execute interest rate swap, cap and floor agreements to effectively fix or limit the interest rate exposure on the underlying financing.

Foreign Exchange Rate Risk

We are exposed to foreign currency risk and other foreign operations risk that arise from investments in foreign subsidiaries and affiliates. A key component of this risk is that some of our foreign subsidiaries and affiliates utilize currencies other than our consolidated reporting currency, the U.S. dollar. Additionally, certain of our foreign subsidiaries and affiliates have entered into monetary obligations in U.S. dollars or currencies other than their own functional currencies. Primarily, we are exposed to changes in the U.S. dollar/Brazilian Real exchange rate, the U.S dollar/Euro exchange rate and the U.S. dollar/ British Pound exchange rate. Whenever possible, these subsidiaries and affiliates have attempted to limit potential foreign exchange exposure by entering into revenue contracts that adjust to changes in foreign exchange rates. We also use foreign currency forwards, swaps and options, where possible, to manage our risk related to certain foreign currency fluctuations.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the price of electricity, natural gas and coal. Although we primarily consist of businesses with long-term contracts or retail sales concessions, a portion of our current and expected future revenues are derived from businesses without significant long-term revenue or supply contracts. These businesses subject our results of operations to the volatility of electricity, coal and natural gas prices in competitive markets. Our businesses hedge certain aspects of their net open positions in the U.S. We have used a hedging strategy, where appropriate, to hedge our financial performance against the effects of fluctuations in energy commodity prices. The implementation of this strategy can involve the use of commodity forward contracts, futures, swaps and options as well as long-term supply contracts for the supply of fuel and electricity.

Value at Risk

One approach we use to assess our risk and our subsidiaries risk is value at risk (VaR). VaR measures the potential loss in a portfolio s value due to market volatility, over a specified time horizon, stated with a specific degree of probability. The quantification of market risk using VaR provides a consistent measure of risk across diverse markets and instruments. We adopted the VaR approach because we feel that statistical models of risk measurement, such as VaR, provide an objective, independent assessment of a component of our risk exposure. Our use of VaR requires a number of key assumptions, including the selection of a confidence level for expected losses, the holding period for liquidation and the treatment of risks outside the VaR methodology, including liquidity risk and event risk. VaR, therefore, is not necessarily indicative of actual results that may occur. Additionally, VaR represents changes in fair value and not the economic exposure to AES and its affiliates.

Because of the inherent limitations of VaR, including those specific to Analytic VaR, in particular the assumption that values or returns are normally distributed, we rely on VaR as only one component in our risk assessment process. In addition to using VaR measures, we perform stress and scenario analyses to estimate the economic impact of market changes to our portfolio of businesses. We use these results to complement the VaR methodology.

In addition, the relevance of the VaR described herein as a measure of economic risk is limited and needs to be considered in light of the underlying business structure. The interest rate component of VaR is due to changes in the fair value of our fixed rate debt instruments and interest rate swaps. These instruments themselves would expose a holder to market risk; however, utilizing these fixed rate debt instruments as part of a fixed price contract generation business mitigates the overall exposure to interest rates. Similarly, our foreign exchange rate sensitive instruments are often part of businesses which have revenues denominated in the same currency, thus offsetting the exposure.

We have performed a company-wide VaR analysis of all of our material financial assets, liabilities and derivative instruments. Embedded derivatives are not appropriately measured here and are excluded since VaR is not representative of the overall contract valuation. The VaR calculation incorporates numerous variables that could impact the fair value of our instruments, including interest rates, foreign exchange rates and commodity prices, as well as correlation within and across these variables. We express Analytic VaR herein as a dollar amount of the potential loss in the fair value of our portfolio based on a 95% confidence level and a one-day holding period. Our commodity analysis is an Analytic VaR utilizing a variance-covariance analysis within the commodity transaction management system.

The following table sets forth average daily VaR as of December 31, for the periods indicated.

Average Daily VAR	**2006**	**2005**	**2004**
	(in millions)		
Foreign Exchange	$ 36	$ 34	$ 27
Interest Rate	$ 76	$ 114	$ 110
Commodity	$ 24	$ 19	$ 9

During the year ended December 31, 2006, our average daily VaR for foreign exchange rate-sensitive instruments was $36 million. The daily VaR for foreign exchange rate-sensitive instruments was highest at the end of the second quarter, and equaled $45 million. The daily VaR for foreign exchange rate-sensitive instruments was lowest at the end of the fourth quarter, and equaled $20 million. These amounts include foreign currency denominated debt and hedge instruments. The foreign exchange VaR increased in the third quarter due to short-term hedge instruments. The proportion of non-USD denominated debt has increased in the AES portfolio. The diverse portfolio and low market volatilities contributed to a decrease in the foreign exchange VaR in the latter part of the year.

During the year ended December 31, 2006, our average daily VaR for interest rate-sensitive instruments was $76 million. The daily VaR for interest rate-sensitive instruments was highest at the end of the first quarter, and equaled $111 million. The daily VaR for interest rate-sensitive instruments was lowest at the end of the third quarter and equaled $60 million. These amounts include the financial instruments that serve as hedges and the underlying hedged items. AES had decreased its portfolio of USD-denominated debt which in part led to the decrease in interest rate VaR.

During the year ended December 31, 2006, our average daily VaR for commodity price-sensitive instruments was $24 million. The daily VaR for commodity price-sensitive instruments was highest at the end of the third quarter, and equaled $28 million. The daily VaR for commodity price-sensitive instruments was lowest at the end of the fourth quarter, and equaled $20 million. These amounts include the financial instruments that serve as hedges and do not include the underlying physical assets or contracts that are not permitted to be settled in cash.

Trending daily VaR can provide insight into market volatility or consistency of a company s financial strategy. AES has increased the percentage of its portfolio of Brazilian Real and Euro denominated floating debt and reduced the percentage of US dollar-denominated fixed rate debt. This has in part led to the decrease in Interest Rate VaR from $110 million in 2004 to $76 million in 2006. The AES commodity VaR is reported for financially settled derivative products at its Eastern Energy business in New York State. From 2004 to 2006 there has been an increase in term and magnitude of hedging activity which has led to the increase in the daily VaR from $9 million in 2004 to $24 million in 2006.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
The AES Corporation
Arlington, VA

We have audited the accompanying consolidated balance sheets of The AES Corporation and subsidiaries (the Company) as of December 31, 2006 and 2005, and the related consolidated statements of operations, changes in stockholders equity (deficit), and cash flows for each of the three years in the period ended December 31, 2006. Our audits also included the financial statement schedules on pages S2-S9. These financial statements and financial statement schedules are the responsibility of the Company s management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of The AES Corporation and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board Statement No.158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans* effective in 2006. In 2005, the Company adopted Financial Accounting Standards Board Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations.*

As discussed in Note 1 to the consolidated financial statements, the accompanying 2005 and 2004 consolidated financial statements and financial statement schedules have been restated.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated May 22, 2007 expressed an unqualified opinion on management s assessment of the effectiveness of the Company s internal control over financial reporting and an adverse opinion on the effectiveness of the Company s internal control over financial reporting because of material weaknesses.

DELOITTE & TOUCHE LLP

McLean, VA
May 22, 2007

THE AES CORPORATION
CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2006 AND 2005

	2006	2005 (Restated)(1)
	(in millions)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 1,575	$ 1,321
Restricted cash	548	477
Short-term investments	640	199
Accounts receivable, net of reserves of $239 and $276, respectively	1,903	1,648
Inventory	518	457
Receivable from affiliates	81	73
Deferred income taxes current	213	270
Prepaid expenses	113	119
Other current assets	943	688
Current assets of held for sale and discontinued businesses	31	35
Total current assets	6,565	5,287
NONCURRENT ASSETS		
Property, Plant and Equipment:		
Land	950	860
Electric generation and distribution assets	23,990	22,301
Accumulated depreciation	(6,979)	(5,975)
Construction in progress	1,113	847
Property, plant and equipment, net	19,074	18,033
Other assets:		
Deferred financing costs, net of accumulated amortization of $191 and $219, respectively	285	275
Investments in and advances to affiliates	596	665
Debt service reserves and other deposits	524	546
Goodwill, net	1,419	1,413
Other intangible assets, net of accumulated amortization of $203 and $155, respectively	305	284
Deferred income taxes noncurrent	663	783
Noncurrent assets of held for sale and discontinued businesses	105	265
Other assets	1,627	1,409
Total other assets	5,524	5,640
TOTAL ASSETS	$ 31,163	$ 28,960
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 892	$ 1,091
Accrued interest	412	380
Accrued and other liabilities	2,227	2,107
Current liabilities of held for sale and discontinued businesses	45	51
Recourse debt-current portion	-	200
Non-recourse debt-current portion	1,453	1,447
Total current liabilities	5,029	5,276
LONG-TERM LIABILITIES		
Non-recourse debt	10,102	10,638
Recourse debt	4,790	4,682
Deferred income taxes-noncurrent	790	777
Pension liabilities and other post-retirement liabilities	883	865
Long-term liabilities of held for sale and discontinued businesses	62	136
Other long-term liabilities	3,371	3,334
Total long-term liabilities	19,998	20,432
Minority Interest (including discontinued businesses of $8 and $7, respectively)	3,100	1,626
Commitments and Contingent Liabilities (see Notes 10 and 11)		
STOCKHOLDERS EQUITY		
Common stock ($.01 par value, 1,200,000,000 shares authorized; 665,126,309 and 655,882,836 shares issued and outstanding at December 31, 2006 and 2005, respectively)	7	7
Additional paid-in capital	6,654	6,561
Accumulated deficit	(1,025)	(1,286)
Accumulated other comprehensive loss	(2,600)	(3,656)
Total stockholders equity	3,036	1,626
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 31,163	$ 28,960

(1) See Note 1 related to the restated consolidated financial statements

See notes to consolidated financial statements.

THE AES CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
YEARS ENDED DECEMBER 31, 2006, 2005, AND 2004

	2006	2005 (Restated)(1)	2004 (Restated)(1)
	(in millions, except per share data)		
Revenues:			
Regulated	$ 6,849	$ 6,252	$ 5,172
Non-Regulated	5,450	4,769	4,220
Total revenues	12,299	11,021	9,392
Cost of Sales:			
Regulated	(4,578)	(4,418)	(3,710)
Non-Regulated	(4,090)	(3,404)	(2,891)
Total cost of sales	(8,668)	(7,822)	(6,601)
Gross margin	3,631	3,199	2,791
General and administrative expenses	(305)	(225)	(181)
Interest expense	(1,802)	(1,893)	(1,920)
Interest income	443	395	283
Other expense	(308)	(132)	(123)
Other income	115	171	157
Gain (loss) on sale of investments	98		(1)
Loss on sale of subsidiary stock	(539)		(24)
Asset impairment expense	(29)	(16)	(50)
Foreign currency transaction losses on net monetary position	(77)	(101)	(136)
Equity in earnings of affiliates	72	70	63
INCOME BEFORE INCOME TAXES AND MINORITY INTEREST	1,299	1,468	859
Income tax expense	(403)	(525)	(380)
Minority interest expense	(610)	(369)	(211)
INCOME FROM CONTINUING OPERATIONS	286	574	268
Income (loss) from operations of discontinued businesses net of income tax benefit (expense) of $(9), $33 and $29, respectively	11	34	(59)
(Loss) gain from disposal of discontinued businesses net of income tax benefit of $, $ and $5, respectively	(57)		91
INCOME BEFORE EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	240	608	300
Income from extraordinary items net of income tax expense of $	21		
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	261	608	300
Cumulative effect of change in accounting principle net of income tax benefit of $, $2, and $, respectively		(3)	
Net income	$ 261	$ 605	$ 300
BASIC EARNINGS (LOSS) PER SHARE:			
Income (loss) from continuing operations	$ 0.44	$ 0.89	$ 0.42
Discontinued operations	(0.07)	0.05	0.05
Extraordinary items	0.03		
Cumulative effect of change in accounting principle		(0.01)	
BASIC EARNINGS (LOSS) PER SHARE:	$ 0.40	$ 0.93	$ 0.47
DILUTED EARNINGS (LOSS) PER SHARE:			
Income (loss) from continuing operations	$ 0.43	$ 0.87	$ 0.41
Discontinued operations	(0.07)	0.05	0.05
Extraordinary items	0.03		
Cumulative effect of change in accounting principle		(0.01)	
DILUTED EARNINGS (LOSS) PER SHARE:	$ 0.39	$ 0.91	$ 0.46

(1) See Note 1 related to the restated consolidated financial statements

See notes to consolidated financial statements.

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THE AES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
YEARS ENDED DECEMBER 31, 2006, 2005, AND 2004

	2006	**2005 (Restated)** (1)	**2004 (Restated)** (1)
	(in millions)		
OPERATING ACTIVITIES:			
Net income	$ 261	$ 605	$ 300
Adjustments to net income:			
Depreciation and amortization of intangible assets	933	864	777
Loss from sale of investments and goodwill and asset impairment expense	491	49	74
Loss (gain) on disposal and impairment write-down associated with discontinued operations	62		(98)
Provision for deferred taxes	(37)	135	208
Minority interest expense	611	373	211
Contingencies	173	(10)	28
Loss (gain) on the extinguishment of debt	148	1	(59)
Other	58	132	297
Changes in operating assets and liabilities:			
Decrease (increase) in accounts receivable	84	(29)	(124)
Increase in inventory	(24)	(70)	(32)
Decrease in prepaid expenses and other current assets	8	94	51
Decrease (increase) in other assets	165	84	(51)
(Decrease) increase in accounts payable and accrued liabilities	(400)	(119)	64
(Decrease) increase in other liabilities	(122)	45	(38)
Net cash provided by operating activities	2,411	2,154	1,608
INVESTING ACTIVITIES:			
Capital Expenditures	(1,460)	(826)	(706)
Acquisitions net of cash acquired	(19)	(85)	(20)
Proceeds from the sales of businesses	898	22	35
Proceeds from the sales of assets	24	26	28
Sale of short-term investments	2,011	1,499	1,402
Purchase of short-term investments	(2,359)	(1,345)	(1,388)
(Increase) decrease in restricted cash	(8)	94	(43)
Purchase of emission allowances	(77)	(19)	(5)
Proceeds from the sales of emission allowances	82	42	3
Decrease (increase) in debt service reserves and other assets	46	(100)	(63)
Purchase of long-term available-for-sale securities	(52)		
Other investing	12	31	14
Net cash used in investing activities	(902)	(661)	(743)
FINANCING ACTIVITIES:			
Borrowings under the revolving credit facilities, net	72	53	
Issuance of recourse debt		5	491
Issuance of non-recourse debt	3,097	1,710	2,110
Repayments of recourse debt	(150)	(259)	(1,140)
Repayments of non-recourse debt	(4,059)	(2,651)	(2,534)
Payments for deferred financing costs	(86)	(21)	(109)
Distributions to minority interests	(335)	(186)	(139)
Contributions from minority interests	125	1	24
Issuance of common stock	78	26	16
Financed capital expenditures	(52)	(1)	(6)
Other financing	(7)	(16)	2
Net cash used in financing activities	(1,317)	(1,339)	(1,285)
Effect of exchange rate changes on cash	62	13	6
Total increase (decrease) in cash and cash equivalents	254	167	(414)
Cash and cash equivalents, beginning	1,321	1,154	1,568
Cash and cash equivalents, ending	$ 1,575	$ 1,321	$ 1,154
SUPPLEMENTAL DISCLOSURES:			
Cash payments for interest, net of amounts capitalized	$ 1,718	$ 1,674	$ 1,759
Cash payments for income taxes, net of refunds	$ 479	$ 268	$ 197
SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES:			
Common stock issued for debt retirement (See Note 14)	$	$	$ 168
Brasiliana Energia debt exchange (See Note 14)	$	$	$ 773
Transfer of Infoenergy to Brasiliana	$ 13	$	$
IQP - Buyer's assumption of debt (See Note 20)	$ 30	$	$

(1) See Note 1 related to the restated consolidated financial statements

See notes to consolidated financial statements.

THE AES CORPORATION
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY (DEFICIT)
YEARS ENDED DECEMBER 31, 2006, 2005, AND 2004

	Common Stock Shares (in millions)	Amount	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Other Comprehensive Accumulated Loss	Comprehensive Income
Balance at January 1, 2004 (As Restated) (1)	625.6	$ 6	$ 5,774	$ (2,191)	$ (3,710)	
Net income (Restated) (1)				300		$ 300
Subsidiary sale of stock			482			
Foreign currency translation adjustment (net of reclassification to earnings of $(46) for the sale or write off of investments in foreign entities, net of income tax expense of $15) (Restated) (1)					85	85
Minimum pension liability adjustment (net of income tax expense of $4)					18	18
Change in derivative fair value (including a reclassification to earnings of $88 million, net of tax, and an income tax benefit of $23) (Restated) (1)					(34)	(34)
Comprehensive income (Restated) (1)						$ 369
Issuance of common stock in exchange for cancellation of debt	19.7		168			
Issuance of common stock under benefit plans and exercise of stock options and warrants (net of income tax benefit of $5 million)	4.8	1	34			
Stock compensation (Restated) (1)			20			
Balance at December 31, 2004 (Restated) (1)	650.1	$ 7	$ 6,478	$ (1,891)	$ (3,641)	
Net income (Restated) (1)				605		605
Foreign currency translation adjustment (net of reclassification to earnings of $1 for the sale or write off of investments in foreign entities, net of income tax benefit of $11) (Restated) (1)					72	72
Minimum pension liability adjustment (net of income tax benefit of $10) (Restated) (1)					(12)	(12)
Change in derivative fair value (including a reclassification to earnings of $153 million, net of income tax benefit of $105) (Restated) (1)					(75)	(75)
Comprehensive income (Restated) (1)						$ 590
Issuance of common stock under benefit plans and exercise of stock options and warrants (net of income tax benefit of $14 million)	5.8		62			
Stock compensation (Restated) (1)			21			
Balance at December 31, 2005 (Restated) (1)	655.9	$ 7	$ 6,561	$ (1,286)	$ (3,656)	
Net income				261		261
Subsidiary sale of stock			(35)			
Change in fair value of available for sale securities (net of income tax benefit of $2)					(3)	(3)
Foreign currency translation adjustment (net of income tax expense of $9)					691	691
Minimum pension liability adjustment (net of income tax expense of $2)						
Change in derivative fair value (including a reclassification to earnings of $(6) million, net of an income tax expense of $194)					274	274
Effect of SFAS No. 158 (net of income tax expense of $60)					94	

Comprehensive income						$ 1,223
Issuance of common stock under benefit plans and exercise of stock options and warrants	9.2		97			
Stock compensation			31			
Balance at December 31, 2006	665.1	$ 7	$ 6,654	$ (1,025)	$ (2,600)	

(1) See Note 1 related to the restated consolidated financial statements

See notes to consolidated financial statements.

THE AES CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2006, 2005, AND 2004

1. GENERAL AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The AES Corporation is a holding company that through its subsidiaries and affiliates, (collectively, AES or the Company) operates a geographically diversified portfolio of electricity generation and distribution businesses.

PRINCIPLES OF CONSOLIDATION The consolidated financial statements of the Company include the accounts of The AES Corporation, its subsidiaries, and controlled affiliates. Furthermore, variable interest entities in which the Company has an interest have been consolidated where the Company is identified as the primary beneficiary. Investments in which the Company has the ability to exercise significant influence but not control are accounted for using the equity method. All significant intercompany transactions and balances have been eliminated in consolidation.

USE OF ESTIMATES The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires the Company to make estimates and assumptions that affect reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant items subject to such estimates and assumptions include the carrying value and estimated useful lives of long-lived assets; impairment of goodwill and equity method investments; valuation allowances for receivables and deferred tax assets; the recoverability of deferred regulatory assets and the valuation of certain financial instruments, pension liabilities, environmental liabilities and potential litigation claims and settlements.

CASH AND CASH EQUIVALENTS The Company considers unrestricted cash on hand, deposits in banks, certificates of deposit, and short-term marketable securities with an original maturity of three months or less to be cash and cash equivalents.

RESTRICTED CASH Restricted cash includes cash and cash equivalents which are restricted as to withdrawal or usage. The nature of restrictions includes restrictions imposed by the financing agreements such as security deposits kept as collateral, debt service reserves, maintenance reserves, and others; as well as restrictions imposed by long-term power purchase agreements.

ALLOWANCE FOR DOUBTFUL ACCOUNTS The Company maintains an allowance for doubtful accounts for estimated uncollectible accounts receivable. The allowance is based on the Company s assessment of known delinquent accounts, historical experience, and other currently available evidence of the collectibility and the aging of accounts receivable.

INVESTMENTS Short-term investments consist of investments with original maturities in excess of three months but less than one year.

Securities that the Company has both the positive intent and ability to hold to maturity are classified as held-to-maturity and are carried at historical cost. Other investments that the Company does not intend to hold to maturity are classified as available-for-sale or trading. Unrealized gains or losses on available-for-sale investments are recorded as a separate component of stockholders equity. Investments classified as trading are marked to market on a periodic basis through the statement of operations. Interest and dividends on investments are reported in interest income. Gains and losses on sales of investments are recorded using the specific identification method.

EQUITY INVESTMENTS Investments in which the Company has the ability to exercise significant influence but not control are accounted for using the equity method. The Company evaluates its equity

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method investments for impairment whenever events or changes in circumstances indicate that the carrying amounts of such investments may not be recoverable. The difference between the carrying value of the equity method investment and its estimated fair value is recognized as an impairment when the loss in value is deemed other than temporary.

In accordance with Accounting Principles Board Opinion No. 18, the Company discontinues the application of the equity method when an investment is reduced to zero and does not provide for additional losses when the Company does not guarantee the obligations of the investee or is not otherwise committed to provide further financial support for the investee. The Company resumes the application of the equity method if the investee subsequently reports net income to the extent that the Company s share of such net income equals the share of net losses not recognized during the period the equity method was suspended.

PROPERTY, PLANT, AND EQUIPMENT Property, plant, and equipment is stated at cost. The cost of renewals and betterments that extend the useful life of property, plant and equipment are capitalized.

Construction progress payments, engineering costs, insurance costs, salaries, interest, and other costs relating to construction in progress are capitalized during the construction period, or expensed at the time the Company determines that development of a particular project is no longer probable. The continued capitalization of such costs is subject to ongoing risks related to successful completion, including those related to government approvals, siting, financing, construction, permitting, and contract compliance. Construction in progress balances are transferred to electric generation and distribution assets when each asset is ready for its intended use.

Depreciation, after consideration of salvage value and asset retirement obligations, is computed using the straight-line method over the estimated composite useful lives of the assets. Maintenance and repairs are charged to expense as incurred. Emergency and rotable spare parts inventories are included in electric generation and distribution assets when placed in service and are depreciated over the useful life of the related components.

DEFERRED FINANCING COSTS Financing costs are deferred and amortized over the related financing period using the effective interest method or the straight-line method when it does not differ materially from the effective interest method.

GOODWILL AND OTHER INTANGIBLES In accordance with SFAS No. 142, *Goodwill and Other Intangible Assets*, the Company recognizes goodwill for the excess of the cost of an acquired entity over the net amount assigned to assets acquired and liabilities assumed. The Company evaluates goodwill for impairment on an annual basis and whenever events or changes in circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. The Company s annual impairment testing date is October 1st. The Company accounts for emission allowance as intangible assets.

LONG-LIVED ASSETS In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, the Company evaluates the impairment of long-lived assets based on the projection of undiscounted cash flows when circumstances indicate that the carrying amount of such assets may not be recoverable or the assets meet the held for sale criteria under SFAS No. 144. These events or circumstances may include the relative pricing of wholesale electricity by region, anticipated demand and cost of fuel. If the carrying amount is not recoverable, an impairment charge is recorded for the amount by which the carrying value of the long-lived asset exceeds its fair value. For regulated assets, an impairment charge could be offset by the establishment of a regulatory asset, if rate recovery was probable. For non-regulated assets, an impairment charge would be recorded as a charge against earnings.

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, that is, other than a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for measurement, if available. In

the absence of quoted market prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow projections or other indicators of fair value such as bids received, comparable sales or independent appraisals.

In connection with the periodic evaluation of long-lived assets in accordance with the requirements of SFAS No. 144, the fair value of the asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. In cases of impairment described in Note 17, we made our best estimate of fair value using valuation methods based on the most current information at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions, and management s analysis of the benefits of the transaction.

ASSET RETIREMENT OBLIGATIONS The Company adopted SFAS No. 143, *Accounting for Asset Retirement Obligations* in 2003. SFAS No. 143 requires the Company to record the fair value of a legal liability for an asset retirement obligation in the period in which it is incurred. When a new liability is recorded the Company will capitalize the costs of the liability by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company settles the obligation for its recorded amount or incurs a gain or loss.

The Company s retirement obligations covered by SFAS No. 143 primarily include active ash landfills, water treatment basins and the removal or dismantlement of certain plant and equipment. As of December 31, 2006 and 2005, the Company had recorded liabilities of approximately $57 million and $51 million, respectively, related to asset retirement obligations. There are no assets that are legally restricted for purposes of settling asset retirement obligations.

The following table summarizes the amounts recorded, which were related to asset retirement obligations, during the years ended December 31, 2006 and 2005:

	2006	2005
	(in millions)	
Balance at January 1	$ 51	$ 25
Additional liability recorded from cumulative effect of accounting change		18
Additional liabilities incurred in the current period		8
Accretion expense	4	2
Change in estimated cash flows	1	(1)
Translation adjustments	1	(1)
Balance at December 31	$ 57	$ 51

CONDITIONAL ASSET RETIREMENT OBLIGATIONS In March 2005, the FASB issued FASB Interpretation (FIN) No. 47 *Accounting for Conditional Asset Retirement Obligations* which requires the Company to record the estimated fair value of conditional asset retirement obligations. The Company s asset retirement obligations covered by FIN No. 47 primarily include conditional obligations to demolish assets or return assets in good working condition at the end of the contractual or concession term, and for the removal of equipment containing asbestos and other contaminants. The Company recognized a cumulative effect adjustment in the statement of operations in 2005 of $2 million related to the adoption of FIN No. 47.

GUARANTOR ACCOUNTING Pursuant to FIN No. 45, *Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Direct Guarantees of Indebtedness of Others*, at the inception of a guarantee, the Company records the fair value of a guarantee as a liability, with the offset dependent on the circumstances under which the guarantee was issued.

INCOME TAXES Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of the existing assets and liabilities, and their respective income tax bases. The Company establishes a valuation allowance when it is more likely than not that all or a portion of a deferred tax asset will not be realized. Contingent liabilities related to income taxes are recorded when the criteria for loss recognition under SFAS No. 5 *Accounting for Contingencies*, as amended, have been met.

FOREIGN CURRENCY TRANSLATION A business functional currency is the currency of the primary economic environment in which the business operates and is generally the currency in which the business generates and expends cash. Subsidiaries and affiliates whose functional currency is other than the U.S. dollar translate their assets and liabilities into U.S. dollars at the current exchange rates in effect at the end of the fiscal period. The revenue and expense accounts of such subsidiaries and affiliates are translated into U.S. dollars at the average exchange rates that prevailed during the period. Translation adjustments are included in accumulated other comprehensive loss, a separate component of stockholders equity. Gains and losses on intercompany foreign currency transactions which are long-term in nature, which the Company does not intend to settle in the foreseeable future, are also recorded in accumulated other comprehensive loss. Gains and losses that arise from exchange rate fluctuations on transactions denominated in a currency other than the functional currency are included in determining net income. For subsidiaries operating in highly inflationary economies, the U.S. dollar is considered to be the functional currency.

REVENUE RECOGNITION The revenue of the Utilities businesses is classified as regulated on the consolidated statement of operations. Revenues from the sale of energy are recognized in the period during which the sale occurs. The calculation of revenues earned but not yet billed is based on the number of days not billed in the month, the estimated amount of energy delivered during those days and the estimated average price per customer class for that month. The revenues from the Generation segment are classified as non-regulated and are recorded based upon output delivered and capacity provided at rates as specified under contract terms or prevailing market rates. Revenues from power sales contracts entered into after 1991 with decreasing scheduled rates are recognized based on the output delivered at the lower of the amount billed or the average rate over the contract term.

GENERAL AND ADMINISTRATIVE EXPENSES Corporate and other expenses include general and administrative expenses related to corporate staff functions and/or initiatives primarily executive management, finance, legal, human resources, information systems and certain development costs which are not allocable to our business segments.

DEFERRED REGULATORY ASSETS AND LIABILITIES The Company accounts for certain of its regulated operations under the provisions of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*. As a result, AES records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. Regulatory assets generally represent incurred costs that have been deferred due to the probability of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes, recent rate orders applicable to other regulated entities and the status of any pending or potential deregulation legislation. If future recovery of costs ceases to be probable, the asset write-offs would be required to be recognized in operating income.

DERIVATIVES The Company enters into various derivative transactions in order to hedge its exposure to certain market risks. AES primarily uses derivative instruments to manage its interest rate, commodity, and foreign currency exposures. The Company does not enter into derivative transactions for trading purposes.

Under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, the Company recognizes all derivatives as either assets or liabilities in the balance sheet and measures those instruments at fair value. Changes in fair value of derivatives are recognized in earnings unless specific hedge criteria are met. Income and expense related to derivative instruments are recorded in the same category as generated by the underlying asset or liability.

SFAS No. 133 enables companies to designate qualifying derivatives as hedging instruments based on the exposure being hedged. These hedge designations include fair value hedges and cash flow hedges. Changes in the fair value of a derivative that is highly effective as, and is designated and qualifies as, a fair value hedge are recognized in earnings as offsets to the changes in fair value of the exposure being hedged. Changes in the fair value of a derivative that is highly effective as, and is designated as and qualifies as, a cash flow hedge are deferred in accumulated other comprehensive income and are recognized into earnings as the hedged transactions occur. Any ineffectiveness is recognized in earnings immediately. For all hedge contracts, the Company provides formal documentation of the hedge and effectiveness testing in accordance with SFAS No. 133. If AES deems that the derivative is not highly effective as a hedge, hedge accounting will be discontinued prospectively.

For cash flow hedges of forecasted transactions, AES estimates the future cash flows represented by the forecasted transactions, as well as evaluates the probability of occurrence and timing of such transactions. Changes in conditions or the occurrence of unforeseen events could require discontinuance of hedge accounting or could affect the timing for the reclassification of gains or losses on cash flow hedges from accumulated other comprehensive loss into earnings.

STOCK OPTIONS The Company accounts for stock-based compensation plans under the fair value recognition provision of SFAS No. 123, as amended by SFAS No. 148, prospectively to all employee awards granted, modified or settled after January 1, 2003.

The new standard requires companies to recognize compensation cost relating to share-based payment transactions in their financial statements. That cost is to be measured based on the fair value of the equity or liability instruments issued. Starting January 1, 2003, we accounted for our share-based compensation awards under the fair value method prescribed under SFAS No. **123** and accounted for forfeitures on an actual basis, and therefore had reversed compensation expense in the period an award was forfeited. **The method was applied prospectively for all employee awards granted, modified or settled after January 1, 2003. Currently, we use a Black-Scholes Option pricing model to estimate the fair value of stock options granted to employees.**

In April 2005, the SEC amended the compliance dates for SFAS No. 123(R), to allow companies to implement the standard at the beginning of their next fiscal year, instead of the next reporting period beginning after June 15, 2005. Accordingly, AES adopted SFAS No. 123(R) effective January 1, 2006. For transition purposes, AES elected the modified prospective application method. Under this application method, SFAS No. 123(R) applies to new awards and to awards modified, repurchased, or cancelled after the required effective date.

On November 10, 2005, the FASB released the final FASB Staff Position No. SFAS 123(R)-3, *Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards* (FSP SFAS 123(R)-3). Effective January 1, 2006, AES adopted FSP SFAS 123(R)-3, which provides the Company the option to use the short-cut method for calculating the historical pool of windfall tax benefits upon adopting FAS 123(R).

SALES OF STOCK BY A SUBSIDIARY Sales of stock by a subsidiary of the Company are accounted for as capital transactions pursuant to the SEC s Staff Accounting Bulletin No. 51 *Accounting for Sales of Stock by a Subsidiary* (SAB 51).

PENSION AND OTHER POSTRETIREMENT PLANS The Company adopted SFAS 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, effective December 31, 2006, which requires recognition of an asset or liability in the balance sheet reflecting the funded status of pension and other postretirement benefits plans with current-year changes in the funded status recognized in stockholders equity. The Company recorded a cumulative adjustment to adopt the recognition provisions of SFAS No. 158 as of December 31, 2006. See Note 12 to these consolidated financial statements for the impact of the adoption of SFAS No. 158. AES will adopt the measurement date provisions of the standard for the fiscal year ending December 31, 2008.

NEW ACCOUNTING PRONOUNCEMENTS

Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157 *Fair Value Measurement*, (SFAS No. 157). SFAS No. 157 provides enhanced guidance for using fair value to measure assets and liabilities. The standard applies whenever other standards require (or permit) assets or liabilities to be measured at fair value. The standard does not expand the use of fair value in any new circumstances.

Over 40 current accounting standards within GAAP require (or permit) entities to measure assets and liabilities at fair value. Prior to the issuance of SFAS No. 157, the methods for measuring fair value were diverse and inconsistent, especially for items that are not actively traded. The standard clarifies that for items that are not actively traded, such as certain kinds of derivatives, fair value should reflect the price in a transaction with a market participant, including an adjustment for risk, not just the company s mark-to-model value. The standard also requires expanded disclosure of the effect on earnings for items measured using unobservable data.

Under SFAS No. 157, fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the reporting entity transacts. SFAS No. 157 clarifies the principle that fair value should be based on the assumptions market participants would use when pricing the asset or liability. In support of this principle, the standard establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data, for example, the reporting entity s own data. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy.

SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. We are currently evaluating the effect of this new standard on our consolidated financial statements.

Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109

FASB Interpretation 48, *Accounting for Uncertainty in Income Taxes* (FIN No. 48) clarifies the accounting for uncertainty in income taxes recognized in our financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes* (SFAS No. 109). FIN No. 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. It also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition.

The evaluation of a tax position is a two-step process.

The first step is recognition: The enterprise determines whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more-likely-than-not recognition threshold, the enterprise should presume that the position will be examined by the appropriate taxing authority that would have full knowledge of all relevant information.

The second step is measurement: A tax position that meets the more-likely-than-not recognition threshold is measured to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement.

Differences between tax positions taken in a tax return and amounts recognized in the financial statements will generally result in one or a combination of the following:

- An increase in a liability for income taxes payable or a reduction of an income tax refund receivable
- A reduction in a deferred tax asset or an increase in a deferred tax liability

A liability for unrecognized tax benefits will be classified as current to the extent that we anticipate making a payment within one year or the operating cycle, if longer. An income tax liability should not be classified as a deferred tax liability unless it results from a taxable temporary difference (that is, a difference between the tax basis of an asset or a liability as calculated using this Interpretation and its reported amount in the statement of financial position). FIN No. 48 does not change the classification requirements for deferred taxes.

Tax positions that previously failed to meet the more-likely-than-not recognition threshold will be recognized in the first subsequent financial reporting period in which that threshold is met. Previously recognized tax positions that no longer meet the more-likely-than-not recognition threshold will be derecognized in the first subsequent financial reporting period in which that threshold is no longer met. Use of a valuation allowance as described in SFAS No. 109 is not an appropriate substitute for the derecognition of a tax position. The requirement to assess the need for a valuation allowance for deferred tax assets based on the sufficiency of future taxable income is unchanged by FIN No. 48.

The Company adopted FIN No. 48 on January 1, 2007 and estimates the cumulative effect of the change in accounting principle to result in a decrease to retained earnings of approximately $50 to $100 million.

SFAS No. 159 The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FAS 115 (*SFAS 159* ***).***

In February 2007, the FASB issued SFAS 159, which allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item s fair value in subsequent reporting periods must be recognized in current earnings. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between entities that elect different measurement attributes for similar assets and liabilities. SFAS 159 is effective for the Company on January 1, 2008. We have not assessed the impact of SFAS 159 on our consolidated results of operations, cash flows or financial position.

EITF 06-6: Application of Issue No. 05-7 Debtor s Accounting for a Modification (or Exchange) of Convertible Debt Instruments

In June 2006 the FASB Emerging Issue Task Force (EITF) issued EITF 06-6 Application of Issue No. 05-7 *Debtor s Accounting for a Modification (or Exchange) of Convertible Debt Instruments*. This guidance that addresses the treatment of a) whether a change in the fair value of an embedded conversion option resulting from a modification of a convertible debt instrument should be included in the analysis of whether there has been a substantial change in the debt instrument terms for determination if a debt extinguishment has occurred and b) how an issuer should account for modifications that do not result in a debt extinguishment. The consensus was made by the EITF that the change in the fair value of an embedded conversion option resulting from an exchange of or modification in the terms of debt instruments should not be included in the cash flow test to determine whether debt extinguishment accounting should be applied. It was also determined that when a convertible debt instrument is modified or exchanged in a transaction that is not accounted for as an extinguishment, an increase in the fair value of the embedded conversion option should reduce the carrying amount of the debt instrument with a corresponding increase in additional paid in capital.

The consensus in this Issue should be applied to modifications or exchanges of debt instruments occurring in interim or annual reporting periods beginning after Board ratification on November 29, 2006. We are currently evaluating the effect of this Issue on our consolidated financial statements.

EITF 06-7: Issuer s Accounting for a Previously Bifurcated Conversion Option in a Convertible Debt Instrument When the Conversion Option No Longer Meets the Bifurcation Criteria in FASB Statement No. 133

In September 2006 the FASB Emerging Issue Task Force (EITF)issued EITF 06-7 *Issuer s Accounting for a Previously Bifurcated Conversion Option in a Convertible Debt Instrument When the Conversion Option No Longer Meets the Bifurcation Criteria in FASB Statement No. 133* that addresses the ability for an entity to issue convertible debt with an embedded conversion option that is required to be bifurcated under SFAS 133 *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133) if all conditions are met. The EITF reached a consensus that when an embedded conversion option in a convertible debt instrument no longer meets the bifurcation criteria in SFAS 133, an issuer should account for the previously bifurcated conversion option by reclassifying the carrying amount of the liability for the conversion option to shareholder s equity. Any debt discount recognized when the conversion option was bifurcated from convertible debt should continue to be amortized. It was also determined that if a holder exercises a conversion option for which the carrying amount has previously been reclassified to shareholders equity, the issuer should recognize any unamortized discount remaining at the date of conversion immediately as interest expense. All relevant information pertaining to the period in which an embedded conversion option previously accounting under SFAS 133 no longer meets the separation criteria addressed in the pronouncement should be disclosed in the footnotes to the financial statements.

The consensus in this Issue should be applied to previously bifurcated conversion options in convertible debt instruments that cease to meet the bifurcation criteria in SFAS 133 in interim or annual reporting periods beginning after December 15, 2006. We are currently evaluating the effect of this Issue on our consolidated financial statements.

EITF 06-11: Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards

In November 2006 the FASB Emerging Issue Task Force (EITF) issued EITF 06-11 *Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards* that addresses how a company should recognize the income tax benefit related to the payment of dividends on equity-classified employee share-based payment awards that are charged to retained earnings pursuant to SFAS 123(R) *Share Based Payment.* The EITF reached a consensus that the appropriate treatment of the income tax benefit should be recognized as an increase in additional paid-in capital. The realized income tax benefit recognized in additional paid-in capital should be included in the pool of excess tax benefits available to absorb future tax deficiencies on share-based payment awards. The tax benefit incurred for dividends paid to employees for non-vested equity-classified employee share-based payment awards shall not be recognized until the respective deduction reduces income taxes payable.

The consensus in this Issue should be applied prospectively to the income tax benefits of dividends on equity-classified employee share-based payment awards that are declared in fiscal years beginning after September 15, 2007. We are currently evaluating the effect of this Issue on our consolidated financial statements.

RESTATEMENT

The Company has previously identified certain material weaknesses related to its system of internal control over financial reporting. These material weaknesses, as described in the Company s previously filed Form 10K for the year ended December 31, 2005 included the following general areas:

- Aggregation of control deficiencies at our Cameroonian subsidiary;
- Lack of U.S. GAAP expertise in Brazilian businesses;
- Treatment of intercompany loans denominated in other than the functional currency;
- Derivative accounting; and
- Income taxes.

During the fourth quarter 2006, in conjunction with continued remediation of our material weaknesses and overall strengthening of controls across our business, the Company identified certain additional errors which required the restatement of previously issued consolidated financial statements for the years ended December 31, 2005 and December 31, 2004 and for the previously issued interim periods ending March 31, 2006, June 30, 2006 and September 30, 2006.

The restatement adjustments resulted in a decrease to previously reported income from continuing operations and net income of $24 million for the year ended December 31, 2005 and an increase of $2 million for the year ended December 31, 2004. Additionally, the cumulative adjustment for all periods prior to 2004 resulted in an increase to accumulated deficit of $50 million.

The following table quantifies the net impact of the restatement corrections by key income statement line items for the years ended December 31, 2005 and 2004 and includes the resulting impact on diluted earnings per share from continuing operations. The primary line items affected include revenue, cost of sales, gain (loss) on foreign currency transactions, income tax expense and the related impacts on minority interest expense.

	Year Ended December 31, 2005	2004
	(in millions, except per share amounts)	
Income from continuing operations as previously reported	$ 598	$ 266
Changes in income from continuing operations from restatement due to:		
Increase in revenue	25	1
Decrease in cost of sales	5	18
(Increase) decrease in general and administrative expense	(4)	1
Increase in other income	11	1
(Increase) in goodwill and asset impairment expense	(6)	(1)
(Increase) decrease in foreign currency transaction losses	(13)	27
Decrease in equity earnings of affiliates	(6)	(7)
(Increase) in income tax expense	(27)	(24)
(Increase) in minority interest and other (1)	(9)	(14)
(Decrease) increase in income from continuing operations	(24)	2
Income from continuing operations as restated	$ 574	$ 268
Diluted earnings per share from continuing operations as previously reported	$ 0.90	$ 0.41
Changes due to restatement effects	(0.03)	
Diluted earnings per share from continuing operations as restated	$ 0.87	$ 0.41
Diluted shares outstanding	664.6	648.1

(1) Minority interest and other includes $12 million and $13 million of minority interest expense for the periods ending December 31, 2005 and December 31, 2004, respectively, related to the impact of the restatement adjustments at entities with minority interests.

The Company has been cooperating with an informal inquiry by the SEC Staff concerning the Company s restatements and related matters, and has been providing information and documents to the SEC Staff on a voluntary basis. Because the Company is unable to predict the outcome of this inquiry, and the SEC Staff may disagree with the manner in which the Company has accounted for and reported the financial impact of the adjustments to previously filed financial statements, there may be a risk that the inquiry by the SEC could lead to circumstances in which the Company may have to further restate previously filed financial statements, amend prior filings or take other actions not currently contemplated.

The restatement adjustments include several key categories as described below:

Brazil Adjustments

Prior year errors related to certain subsidiaries in Brazil include the following:

- decrease of the U.S. GAAP fixed asset basis and related depreciation at Eletropaulo of $21 million in 2005 and $16 million in 2004 (the impact net of tax and minority interest is $4 million in 2005 and $4 million in 2004); and

- other errors identified through account reconciliation or review procedures.

The cumulative impact on net income was an increase of $6 million and $3 million for the years ended December 31, 2005 and 2004, respectively.

La Electricidad de Caracas (EDC)

Prior year errors related to the Company s Venezuelan subsidiary, EDC, include the following:

- $22 million revenue increase predominantly related to an error in updating the current tariff rates in the unbilled revenue calculation for 2005,
- $10 million increase in foreign currency transaction expense posted incorrectly to the balance sheet in 2005, and
- other errors identified through account reconciliation or review procedures.

The cumulative impact of all EDC adjustments on net income was an increase of $2 million for each of the years ended December 31, 2005 and 2004.

Capitalization of Certain Costs

Certain errors were discovered with fixed asset balances at several of the Company s facilities related to capitalization of development costs, overhead and capitalized interest. The cumulative impact on net income for capitalization errors was a decrease of $4 million for the year ended December 31, 2005 and a decrease of $2 million for the year ended December 31, 2004.

Derivatives

Adjustments were identified resulting from the detailed review of certain prior year contracts and include the following:

- the evaluation of hedge effectiveness; and
- the identification and evaluation of derivatives.

The most significant adjustment involved a power sales agreement signed in 2002 between the Company s generation facility in Cartagena, Spain, an unconsolidated subsidiary accounted for using the equity method of accounting, and its power offtaker. The power sales agreement had a pricing component that was tied to the U.S. dollar, although the entity s own functional currency was the Euro and that of the offtaker was the Euro. In addition, a maintenance service agreement related to the Cartagena facility included a pricing mechanism that was tied to changes in the U.S. dollar, when the entity s functional currency was the Euro and the service provider s functional currency was the Yen.

Under the guidance of Statement of Financial Accounting Standard (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities,* these contracts contained embedded derivatives that are required to be bifurcated from the contract and recorded at fair value with changes in fair value recognized in the results of operations. The net result of these adjustments was a decrease of $3 million and an increase of $4 million in equity in earnings of affiliates for the years ended December 31, 2005 and 2004, respectively.

The cumulative impact of all derivative adjustments on net income was a decrease of $4 million in 2005 and an increase of $5 million in 2004.

Income Tax Adjustments

Income tax adjustments relate primarily to the following:

- A $20 million adjustment to correct income tax expense in the fourth quarter of 2005 as a result of an incorrect 2004 tax return to accrual adjustment, previously disclosed in the Company s Form 10-Q for September 30, 2006; and

- A $21 million adjustment to record income tax benefit in 2004 as a result of a change in local income tax reporting for leases in Qatar, offset by adjustments to correct income tax expense for certain state deferred tax assets and other miscellaneous items.

The net impact of individual income tax adjustments resulted in an increase to income tax expense of approximately $18 million in 2005 and $7 million in 2004. The cumulative impact on income tax expense as a result of all restatement adjustments was an increase of approximately $27 million for the year ended December 31, 2005 and an increase of approximately $24 million for the year ended December 31, 2004.

Other Adjustments

As a result of work performed in the course of our year end closing process, certain other adjustments were identified which decreased net income by $6 million for the year ended December 31, 2005 and increased net income by $1 million for the year ended December 31, 2004.

Balance Sheet Adjustments

Adjustments at certain businesses in Brazil

The Company s Brazilian business, Sul, records customer receipts used to provide line extensions as an offset against property, plant and equipment. However, the regulatory body of Brazil never issued any guidance with respect to the treatment of these customer receipts. As such, we believe that a more appropriate classification of these customer receipts would have been as a regulatory liability given that the actual treatment as an offset against property, plant and equipment was never approved by the regulatory body of Brazil. Additionally, the regulatory liability treatment provides for the possibility of a future obligation back to the customers, which was confirmed by a recent regulatory ruling. The increase to property, plant and equipment and increase to long-term regulatory liabilities was $93 million and $62 million at December 31, 2005 and 2004, respectively.

Cartagena Deconsolidation

Upon the Company s adoption of Financial Interpretation No.46, Variable Interest Entities (FIN No. 46R), as of January 1, 2004, the Company incorrectly continued to consolidate our business in Cartagena, Spain. An adjustment was made to deconsolidate the Cartagena balance sheet and statement of operations and to reflect AES share of the results of its operations using the equity method of accounting. This resulted in a decrease to investments in affiliates of $55 and $39 million; a decrease in net property, plant and equipment of $570 and $387 million; and a decrease in non-recource debt of $579 and $497 million at December 31, 2005 and 2004, respectively.

Restricted Cash

Certain balance sheet reclassifications were recorded at December 31, 2005 and December 31, 2004 that were the result of errors in the presentation of restricted cash. These reclasses resulted in a reduction in cash and cash equivalents and an increase in restricted cash by $63 million and $97 million, in 2005 and 2004, respectively

Share-based Compensation

The Company recently concluded an internal review of accounting for share-based compensation (the LTC Review), which originally was disclosed in the Company s Form 8-K filed on February 26, 2007. As a result of the LTC Review, the Company identified certain errors in its previous accounting for share-based compensation. These errors required adjustments to the Company s previous accounting for these awards under the guidance of Accounting Principles Board Opinion No. 25, *Accounting for Stock*

Issued to Employees (APB No. 25), Financial Accounting Standards Board (FASB) Statement No. 123, *Accounting for Stock-Based Compensation* (FAS No. 123) and FASB Statement No. 123R (revised 2004), *Share-Based Payment* (FAS No. 123R). As described below, the Company is recording adjustments to its prior financial statements resulting in additional cumulative pre-tax compensation expense for the years 2000-2005 of $36 million ($26 million net of taxes).

A significant accounting issue identified in the LTC Review related to the determination of the measurement date with respect to share-based compensation awards. During the Review Period, the Company had generally used the grant date as the measurement date for accounting purposes, when in many cases the indicated grant date actually preceded the measurement date as correctly defined under Generally Accepted Accounting Principles (GAAP). The U.S. GAAP technical accounting literature in effect during the accounting periods under review includes varying definitions of the measurement date for purposes of determining share-based compensation expense. Under APB No. 25, applicable for the years 1997-2002, the measurement date for share-based compensation expense was defined as the date at which the Company finalized an individual s share-based award, to include the number of units awarded at a determinable strike price. Under SFAS No. 123, the measurement date is determined when the share-based award is finalized and communicated to the individual.

Purposes and Scope of the LTC Review

The LTC Review was designed and conducted principally to determine whether any adjustments to the Company s prior period financial statements were required as a result of incorrect accounting for share-based compensation, which includes stock options and restricted stock units.

The Company s Accounting Adjustments

As a result of the LTC Review, the Company has determined that adjustments resulting in charges for share-based compensation should be recorded for the years 2000 through 2005. The additional cumulative pre-tax compensation expense totals $36 million ($26 million net of taxes). The effect of recognizing additional non-cash, share-based compensation expense resulting from the charges mentioned above by year is as follows:

Fiscal Year Ended (in millions)	Pre-Tax Expense	After-Tax Expense
2000	$ 8	$ 6
2001	$ 15	$ 11
2002	$ 8	$ 5
2003	$ 4	$ 3
2004	$	$
2005	$ 1	$ 1

The Company also is recording a charge of $1 million (pre-tax) relating to the first three previously reported quarters of 2006, which primarily relate to prior year grants in which expense was carried forward to 2006.

The Company will reflect these adjustments by reducing stockholders equity by $25 million as of January 1, 2004 for the cumulative effect of the correction of errors for the periods from January 1, 2000 through December 31, 2003. General and administrative expense will be adjusted for the years ending December 31, 2004 and 2005 and the first three quarters of 2006 as outlined above.

Selected Balance Sheet Data

	December 31, 2005 As Previously Reported (in millions)	As Restated
Assets		
Accounts receivable, net of reserves	$ 1,597	$ 1,648
Other current assets	$ 752	$ 688
Total current assets	$ 5,232	$ 5,287
Property, plant and equipment, net	$ 18,493	$ 18,033
Liabilities and Stockholders' Equity		
Accounts payable	$ 1,093	$ 1,091
Accrued and other liabilities	$ 2,101	$ 2,107
Total current liabilities	$ 5,406	$ 5,276
Deferred income taxes	$ 721	$ 777
Other long-term liabilities	$ 3,279	$ 3,334
Total long-term liabilities	$ 20,766	$ 20,432
Minority interest	$ 1,611	$ 1,626
Additional paid-in capital	$ 6,517	$ 6,561
Accumulated deficit	$ (1,214)	$ (1,286)
Accumulated other comprehensive loss	$ (3,661)	$ (3,656)
Total Liabilities and Stockholders' Equity	$ 29,432	$ 28,960

Selected Operations and Comprehensive Income (Loss) Data:

	December 31, 2005 Previously Reported	As Restated	December 31, 2004 Previously Reported	As Restated
	(in millions, except per share data)			
Interest expense	$ 1,891	$ 1,893	$ 1,921	$ 1,920
Foreign currency transaction losses on net monetary position	$ 88	$ 101	$ 163	$ 136
Income tax expense	$ 498	$ 525	$ 356	$ 380
Minority interest expense	$ 357	$ 369	$ 198	$ 211
Income from continuing operations	$ 598	$ 574	$ 266	$ 268
Net income	$ 630	$ 605	$ 298	$ 300
Foreign currency translation adjustment	$ 57	$ 72	$ 110	$ 85
Minimum pension liability adjustment	$ (6)	$ (12)	$ 18	$ 18
Unrealized derivative losses	$ (71)	$ (75)	$ (64)	$ (34)
Comprehensive income	$ 610	$ 590	$ 362	$ 369
BASIC EARNINGS (LOSS) PER SHARE:				
Income (loss) from continuing operations	$ 0.91	$ 0.89	$ 0.42	$ 0.42
Discontinued operations	0.05	0.05	0.05	0.05
Cumulative effect of change in accounting principle		(0.01)		
BASIC EARNINGS (LOSS) PER SHARE:	$ 0.96	$ 0.93	$ 0.47	$ 0.47
DILUTED EARNINGS (LOSS) PER SHARE:				
Income (loss) from continuing operations	$ 0.90	$ 0.87	$ 0.41	$ 0.41
Discontinued operations	0.05	0.05	0.05	0.05
Cumulative effect of change in accounting principle		(0.01)		
DILUTED EARNINGS (LOSS) PER SHARE:	$ 0.95	$ 0.91	$ 0.46	$ 0.46

Selected Cash Flows Data:

	December 31, 2005 Previously Reported (in millions)	As Restated	December 31, 2004 Previously Reported	As Restated
Net income	$ 630	$ 605	$ 298	$ 300
Adjustments to net income:				
Depreciation and amortization of intangible assets	$ 889	$ 864	$ 799	$ 777
Provision for deferred taxes	$ 100	$ 135	$ 190	$ 208
Minority interest expense	$ 361	$ 373	$ 199	$ 211
Other	$ 92	$ 132	$ 322	$ 297
Changes in operating assets and liabilities:				
(Decrease) increase in other assets	$ 90	$ 84	$ (71)	$ (51)
(Decrease) increase in accounts payable and accrued liabilities	$ (79)	$ (119)	$ 78	$ 64
Increase (decrease) in other liabilities	$ 45	$ 45	$ (37)	$ (38)
Net cash provided by operating activities	$ 2,165	$ 2,154	$ 1,571	$ 1,608

2. INVESTMENTS

The following table sets forth the Company s investments as of December 31, 2006 and 2005:

	December 31, 2006 (in millions)	2005
HELD-TO-MATURITY:		
Certificates of deposit	$ 46	$ 16
Mutual funds	2	1
Government debt securities	2	6
Less: discontinued operations		(4)
Subtotal	50	19
AVAILABLE-FOR-SALE:		
Government debt securities	261	87
Mutual Funds	248	80
Common Stock	47	
Certificates of Deposits	43	5
Money market funds	34	5
Auction Rate Securities		1
Subtotal	633	178
TRADING:		
Government debt securities	4	2
Subtotal	4	2
Total Short-term Investments	640	199
Total Long-term investments	47	
TOTAL	$ 687	$ 199

The investments are classified as either held-to-maturity, available-for-sale or trading. The amortized cost and estimated fair value of the held-to-maturity investments were approximately the same at December 31, 2006 and 2005. The available-for-sale and trading investments are recorded at fair value. At

December 31, 2006 and 2005, approximately $8 million and $10 million, respectively, of investments classified as held-to-maturity were restricted or pledged as collateral.

As of December 31, 2006, the stated maturities for the investments (including restricted investments) ranged from four months to 30 years.

At December 31, 2006, there was $3 million included in accumulated other comprehensive loss for available-for-sale securities and no balance at December 31, 2005. Proceeds from the sales of available-for-sale securities were $1.6 billion, $1.1 billion and $1.3 billion for the years ended December 31, 2006, 2005 and 2004, respectively. Gross realized gains on these sales were $31 million and $3 million for the years ended December 31, 2005 and 2004, respectively. There were no realized gains recognized on sales of available-for-sale securities in 2006. The cost of the securities is determined using the specific identification method.

The Company made its first significant investment in the greenhouse gas emission area, acquiring a 9.9% ownership interest in AgCert International (AgCert) for $52 million. AgCert is an Ireland-based company which uses agricultural sources to produce greenhouse gas emission offsets under the Kyoto protocol. This investment is classified as long-term available-for-sale investment and is revalued at the end of each reporting period. As of December 31, 2006, the Company has recorded a gross unrealized loss on this investment of $5 million. The Company has deemed this loss to be temporary.

3. INVENTORY

Inventories, for our purposes, consist of the following items: coal, fuel oil and other raw materials used to generate power, and spare parts and supplies used to maintain power generation and distribution facilities.

Most of the Company s inventories are valued on the average cost method (64%) or the first-in, first-out (FIFO) method (28%). Inventories stated under the last-in, first-out (LIFO) method represent 8% of total inventories in 2006. If the FIFO method, which approximates current replacement cost, had been used for these LIFO inventories, the total amount of these inventories would have increased by approximately $18 million. Inventory is accounted for at the lower of cost of market.

The following table summarizes our inventory as of December 31, 2006 and 2005:

	December 31, 2006 (in millions)	2005
Coal, fuel oil and other raw materials	$ 242	$ 232
Spare parts and supplies	276	225
Total	$ 518	$ 457

4. DEFERRED REGULATORY ASSETS & LIABILITIES

The Company has recorded deferred regulatory assets and liabilities that it expects to pass through to its customers in accordance with, and subject to, regulatory provisions as follows:

	December 31, 2006 (in millions)	2005
Current assets	$ 481	$ 438
Noncurrent assets	561	644
Total assets	$ 1,042	$ 1,082
Current liabilities	359	211
Noncurrent liabilities	581	599
Total liabilities	$ 940	$ 810

The current portion of the deferred regulatory asset and liability is recorded in either other current assets or other current liabilities, respectively, on the accompanying consolidated balance sheets. The noncurrent portion of the deferred regulatory asset and liability is recorded in either other assets or other long-term liabilities, respectively, in the accompanying consolidated balance sheets.

Recovery of certain regulatory assets at the Company s subsidiaries is provided without a rate of return during the recovery period. All other regulatory assets are recovered with a rate of return. The following table summarizes the amounts of regulatory assets probable of recovery without a rate of return at December 31, 2006 and 2005.

	December 31, 2006 (in millions)	2005	Recovery Period
Current Assets:			
Deferred fuel costs and other	$ 50	$ 51	Through 2007
Noncurrent Assets (IPL):			
Defined benefit pension obligations	$ 147	$	Service lives of employees
Related to deferred income taxes	81	87	Various
Unamortized reacquisition premium on debt	18	15	Over remaining life of debt
Deferred Midwest ISO costs	35	21	To be determined(1)
Asset retirement obligation costs	10	9	Over book life of assets
Interest rate hedge and other	9	2	Through 2021
Total noncurrent	$ 300	$ 134	
Total	$ 350	$ 185	

(1) Recovery is probable, but not yet determined.

Deferred Fuel: Deferred fuel costs are a component of current regulatory assets and are expected to be recovered through future fuel adjustment charge proceedings. For our El Salvadorian businesses, the deferred fuel adjustment is the result of variances between the actual fuel costs and the fuel costs recovered in the tariffs. Our El Salvadorian businesses are permitted to recover this variance through the reset of future tariffs each six months and therefore, these costs are deferred and amortized into fuel expense in the same period as the tariffs are adjusted. For IPL, the Company records deferred fuel in accordance with standards prescribed by the Indiana Utility Regulatory Commission (IURC). The deferred fuel adjustment is the result of variances between estimated fuel and purchased power costs in IPL s fuel adjustment charge and actual fuel and purchased power costs. IPL is permitted to recover underestimated fuel and purchased power costs in future rates through the fuel adjustment charge proceedings and therefore the costs are deferred and amortized into fuel expense in the same period that IPL s rates are adjusted.

Defined Benefit Pension Obligations: Upon the adoption of SFAS No. 158, the adjustment that IPL would have recorded to Accumulated Other Comprehensive Income to recognize the funded status of its defined benefit plans, has been recorded to Long-term Regulatory Assets. This amount represents a cost allowable to be recovered in future rates.

Related to Deferred Income Taxes: This amount represents the portion of deferred income taxes that are probable of recovery through future rates, based upon established regulatory practices, which permit the recovery of current taxes. Accordingly, this regulatory asset is offset by a deferred tax liability and is expected to be recovered, without interest, over the period underlying book-tax timing differences reverse and become current taxes.

Deferred Midwest ISO costs: These consist of administrative costs for transmission services and other administrative and socialized costs from IPL s participation in the Midwest ISO market. IPL received orders from the Indiana Utility Regulatory Commission that granted authority for the deferral of such costs for recovery in a future base rate case.

Asset Retirement Obligation Costs: This amount represents the portion of legal asset retirement obligation costs that are probable of recovery through future rates, based upon established regulatory practices.

5. PROPERTY, PLANT & EQUIPMENT

The following table summarizes the components of the electric generation and distribution assets and the related rates of depreciation.

	Composite Rate	**Useful Life**
Electric Generation and Distribution Facilities	2.0% - 33.3%	3 - 50 yrs.
Other Buildings	2.0% - 20%	5 - 50 yrs.
Leasehold Improvements	2.9% - 33.3%	3 - 34 yrs.
Furniture and Fixtures	3.3% - 33.3%	3 - 30 yrs.

The following table summarizes the depreciation expense, which is stated as a percentage of the average cost of depreciable property, plant and equipment, for the years ending December 31, 2006, 2005 and 2004.

	December 31,		
	2006	**2005**	**2004**
% of depreciable PP&E	3.8%	3.7%	3.6%

The following table summarizes interest capitalized during development and construction for the years ending December 31, 2006, 2005 and 2004.

	December 31,		
	2006	**2005**	**2004**
	(in millions)		
Interest capitalized during development & construction	$ 49	$ 28	$ 36

Recoveries of liquidating damages from construction delays are recorded as a reduction in the related projects construction costs. Approximately $9.4 billion of property, plant and equipment, net of accumulated depreciation, was mortgaged, pledged or subject to lien as of December 31, 2006.

Depreciation expense was $888 million, $823 million and $751 million for the years ended December 31, 2006, 2005 and 2004, respectively.

6. INVESTMENTS IN AND ADVANCES TO AFFILIATES

US Wind Force, LLC.* *In December 2006, the Company sold its 33% ownership interest in US Wind Force, LLC (US Wind), a private company that focuses on developing wind energy projects in the United States. The sale resulted in a gain of $1 million.

InnoVent SAS* *In October 2006, the Company purchased a 40% interest in InnoVent SAS, a privately held developer of wind energy projects in France. In addition, as part of the transaction, the Company received the option to purchase a majority ownership in the underlying wind farm projects at a future date.

Empresa Generadora de Electricidad Itabo S.A. In May 2006, the Company, through its wholly-owned subsidiary, AES Grand Itabo, purchased an additional 25% interest in Empresa Generadora de Electricidad Itabo S.A. (Itabo), a power generation business located in the Dominican Republic for

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approximately $23 million. Prior to May, the Company held a 25% interest in Itabo indirectly through its Gener subsidiary in Chile and had accounted for the investment using the equity method of accounting. As a result of the transaction, AES now has a 48% economic interest in Itabo, and a majority voting interest, thus requiring consolidation. Through the purchase date in May, the Company s initial 25% share in Itabo s net income is included in the Equity in earnings from affiliates line item on the consolidated income statements. Subsequent to the Company s purchase of the additional 25% interest, Itabo is reflected as a consolidated entity included at 100% in the consolidated financial statements, with an offsetting charge to minority interest expense for the minority shareholders interest. The Company engaged a third-party valuation specialist to determine the purchase price allocation for the additional 25% investment. The valuation resulted in fair values of current assets and total liabilities in excess of the purchase price. Therefore, the Company recognized a $21 million after-tax extraordinary gain on the transaction in the second quarter of 2006.

Kingston Cogeneration Limited Partnership. In March 2006, the Company s wholly-owned subsidiary, AES Kingston Holdings, B.V., sold its 50% indirect ownership interest in Kingston Cogeneration Limited Partnership (KCLP), a 110 MW cogeneration plant located in Ontario, Canada. AES received $110 million in net proceeds for the sale of its investment and recognized a pre-tax gain of $87 million on the sale.

AES Barry Ltd. In July 2003, the Company signed an amended credit agreement related to the outstanding debt of AES Barry Ltd. (Barry), a 230 MW gas-fired combined cycle power plant in the United Kingdom. Although the Company continues to maintain 100% ownership of Barry, as a result of the amended credit agreement, no material financial or operating decisions can be made without the banks consent, and thus the Company no longer had control over Barry. Consequently, the Company discontinued consolidating the business's results and began using the equity method to account for the unconsolidated majority-owned subsidiary.

Companhia Energetica de Minas Gerais. The Company is a party to a joint venture/consortium agreement through which the Company has an equity investment in Companhia Energetica de Minas Gerais (CEMIG), an integrated utility in Minas Gerais, Brazil. The agreement prescribes ownership and voting percentages as well as other matters. In the fourth quarter of 2002, a combination of events occurred related to the CEMIG investment. These events included consistent poor operating performance in part caused by continued depressed demand and poor asset management, the inability to adequately service or refinance operating company debt and acquisition debt, and a continued decline in the market price of CEMIG shares. Additionally, a partner in one of the holding companies in the CEMIG ownership structure sold its interest in this holding company to an unrelated third party in December 2002 for a nominal amount. Upon evaluating these events in conjunction with each other, the Company concluded that an other than temporary decline in value of the CEMIG investment had occurred. Therefore, in December 2002, AES recorded an impairment charge related to the other than temporary decline in value of the investment in CEMIG, and the shares in CEMIG were written-down to fair market value. Additionally, AES recorded a valuation allowance against a deferred tax asset related to the CEMIG investment. The total amount of these charges, net of tax, was $587 million, of which $264 million related to the other than temporary impairment of the investment and $323 million related to the valuation allowance against the deferred tax asset. As a result of these charges, the Company s investment in CEMIG, net of debt used to finance the CEMIG investment, is negative.

In the fourth quarter of 2002, AES lost voting control of one of the holding companies in the CEMIG ownership structure. This holding company indirectly owns the shares related to the CEMIG investment and indirectly holds the project financing debt related to CEMIG. As a result of the loss of voting control, AES stopped consolidating this holding company at December 31, 2002. The Company s equity investment in CEMIG, net of debt used to finance the investment, is $(484) million at December 31, 2006.

Cartagena Energia. The Company owns 71% of a 1200 MW power plant in Cartagena, Spain completed in November 2006. The customer of the plant is the primary beneficiary due to the absorption of commodity price risk.

The financial information tables below exclude information related to Barry and Cartagena, both unconsolidated majority-owned subsidiaries, and the CEMIG business because the Company has discontinued the application of the equity method investment in accordance with its accounting policy regarding equity investments (disclosed in Note 1).

Both of the following tables summarize financial information of the entities in which the Company has the ability to exercise significant influence, but does not control, and which are accounted for using the equity method.

Years ended, December 31,	Revenues (in millions)	Gross Margin	Net Income
2006	$ 938 (1)	$ 275 (1)	$ 202 (1)
2005	1,051	332	163
2004	945	309	170

(1) Includes information pertaining to KCLP through March 2006, Itabo through May 2006, and US Wind through December 2006.

	Current Assets (in millions)	Noncurrent Assets	Current Liabilities	Noncurrent Liabilities	Stockholders Equity
December 31,					
2006	$ 374	$ 1,846	$ 240	$ 913	$ 1,067
2005	512	2,232	345	1,094	1,305

The following table summarizes the relevant effective equity ownership percentages for the Company s investments accounted for under the equity method for the years ending December 31, 2004 through 2006.

Affiliate	Country	December 31, 2006	2005	2004
Barry	United Kingdom	100.00	100.00	100.00
Cartagena	Spain	70.81	70.81	70.81
Cemig	Brazil	9.57	9.57	9.57
Chigen affiliates	China	25.00	25.00	25.00
EDC affiliates	Venezuela	41.08	43.00	43.00
Elsta	Netherlands	50.00	50.00	50.00
Gener affiliates	Chile	45.60	49.00	49.00
InnoVent	France	40.00		
Itabo	Dominican Republic	(1)	25.00	25.00
Kingston Cogen Ltd	Canada	(2)	50.00	50.00
OPGC	India	49.00	49.00	49.00
US Wind	United States	(2)	27.55	17.82

(1) Became a consolidated entity in 2nd quarter 2006 due to increased equity ownership.

(2) Investment was sold during 2006.

At December 31, 2006, retained earnings included $136 million related to the undistributed earnings of affiliates and distributions received from affiliates were $44 million, $82 million and $42 million in 2006, 2005 and 2004, respectively. The Company charged and recognized construction revenues, management fees and interest on advances to its affiliates, which aggregated $2 million, $7 million and $6 million for the years ended December 31, 2006, 2005 and 2004, respectively.

7. GOODWILL AND OTHER INTANGIBLES

SFAS No. 142 requires that goodwill be evaluated for impairment at a level referred to as a reporting unit. A reporting unit is an operating segment as defined by SFAS No. 131*, Disclosures about Segments of*

an Enterprise and Related Information, or one level below an operating segment, referred to as a component. Generally, each AES business constitutes a reporting unit. Reporting units have been acquired generally in separate transactions. In the event that more than one reporting unit is acquired in a single acquisition, the fair value of each reporting unit is determined, and that fair value is allocated to the assets and liabilities of that unit. If the determined fair value of the reporting unit exceeds the amount allocated to the net assets of the reporting unit, goodwill is assigned to that reporting unit.

The following table summarizes the changes in the carrying amount of goodwill, by segment, for the years ending December 31, 2004 through 2006.

	North America Generation (in millions)	North America Utilities	Latin America Generation	Latin America Utilities	Europe & Africa Generation	Europe & Africa Utilities	Asia Generation	Corporate & Other	Total
Carrying amount at December 31, 2004	$ 133	$	$ 907	$ 130	$ 204	$ 6	$ 24	$	$ 1,404
Goodwill acquired during the period								35	35
Translation adjustments and other	(10)		(1)		(15)				(26)
Carrying amount at December 31, 2005	$ 123	$	$ 906	$ 130	$ 189	$ 6	$ 24	$ 35	$ 1,413
Translation adjustments and other	(10)			3	16			(3)	6
Carrying amount at December 31, 2006	$ 113	$	$ 906	$ 133	$ 205	$ 6	$ 24	$ 32	$ 1,419

For the year ended December 31, 2006, the Company recognized goodwill impairment of $2 million. As a result of the Company s annual goodwill impairment testing performed as of October 1st, goodwill at one of our European generation plants was determined to be impaired and such balance was written off. The fair value of the reporting unit was determined by using a discounted cash flow valuation as current quoted market prices were not available and there was not sufficient evidence that the reporting unit could be bought or sold in the market place between willing third parties. There was no impairment of goodwill during the years ended December 31, 2005 and 2004.

The following tables summarize the balances comprising other intangibles in the accompanying consolidated balance sheets for the years ending December 31, 2006 and 2005.

Nature of intangible assets (other than Goodwill)	Gross Balance as of December 31, 2006 (in millions)	Accumulated Amortization as of December 31, 2006	Net Balance as of December 31, 2006
Sales concessions	$ 160	$ (58)	$ 102
Software costs	151	(110)	41
All other	197	(35)	162
TOTAL	$ 508	$ (203)	$ 305

Nature of intangible assets (other than Goodwill)	Gross Balance as of December 31, 2005 (in millions)	Accumulated Amortization as of December 31, 2005	Net Balance as of December 31, 2005
Sales concessions	$ 148	$ (46)	$ 102
Software costs	124	(80)	44
All other	167	(29)	138
TOTAL	$ 439	$ (155)	$ 284

The following table summarizes the estimated amortization expense, broken down by intangible asset category, for 2007 through 2011.

Nature of intangible assets (other than Goodwill)	Estimated amortization expense in 2007	Estimated amortization expense in 2008	Estimated amortization expense in 2009	Estimated amortization expense in 2010	Estimated amortization expense in 2011
Sales concessions	$ 7	$ 7	$ 6	$ 6	$ 6
Software costs	18	12	10	6	4
All other	7	7	6	7	7
TOTAL	$ 32	$ 26	$ 22	$ 19	$ 17

Intangible asset amortization expense was $40 million, $32 million and $15 million for the years ended December 31, 2006, 2005 and 2004, respectively. Intangible assets that are not subject to amortization consist of emission allowances which have a carrying value of $22 million at December 31, 2006 and $7 million at December 31, 2005.

8. LONG-TERM DEBT

The following table summarizes the non-recourse debt of the company at December 31, 2006 and 2005.

Non-recourse debt	Interest Rate(1)	Final Maturity	December 31, 2006 (in millions)	2005
VARIABLE RATE (2):				
Bank loans	6.97 %	2022	$ 3,415	$ 3,693
Notes and bonds	14.65 %	2041	2,077	867
Debt to (or guaranteed by) multilateral or export credit agencies or development banks	11.76 %	2013	144	538
Other	8.08 %	2009	86	758
FIXED RATE:				
Bank loans	8.37 %	2023	358	268
Commercial paper	6.35 %	2007	35	5
Notes and bonds	8.51 %	2036	5,341	5,144
Debt to (or guaranteed by) multilateral or export credit agencies or development banks	9.72 %	2012	20	583
Other	4.89 %	2024	79	229
SUBTOTAL			$ 11,555	$ 12,085
Less: Current maturities			(1,453)	(1,447)
TOTAL			$ 10,102	$ 10,638

(1) Weighted average interest rate at December 31, 2006.

(2) The Company has interest rate swaps and interest rate option agreements in an aggregate notional principal amount of approximately $2.5 billion at December 31, 2006. The swap agreements economically change the variable interest rates on the portion of the debt covered by the notional amounts to fixed rates ranging from approximately 3.78% to 7.49%. The option agreements fix interest rates within a range from 4.51% to 7.00%. The agreements expire at various dates from 2007 through 2023.

The following table summarizes the recourse debt of the company at December 31, 2006 and 2005.

RECOURSE DEBT	Interest Rate	Final Maturity	December 31, 2006 (in millions)	2005
Senior Secured Term Loan	LIBOR + 1.75%	2011	$ 200	$ 200
Second Priority Senior Secured Notes	8.75% 9.00%	2013 2015	1,800	1,800
Senior Unsecured Notes	7.75% 9.50%	2008 2014	2,066	2,046
Senior Subordinated Debentures	8.875%	2027		115
Convertible Junior Subordinated Debentures	6.0% 6.75%	2008 2029	731	731
Unamortized discounts			(7)	(10)
SUBTOTAL			$ 4,790	$ 4,882
Less: Current maturities (1)				(200)
Total			$ 4,790	$ 4,682

(1) Senior Secured Term Loan was classified as a current maturity as of December 31, 2005, because the loan was in default as of March 31, 2006.

NON-RECOURSE DEBT Non-recourse debt borrowings are not a direct obligation of AES, the parent corporation, and are primarily collateralized by the capital stock of the relevant subsidiary and in certain cases the physical assets of, and all significant agreements associated with, such business. These non-recourse financings include structured project financings, acquisition financings, working capital facilities and all other consolidated debt of the subsidiaries.

The terms of the Company s non-recourse debt, which is debt held at subsidiaries, include certain financial and non-financial covenants. These covenants are limited to subsidiary activity and vary among the subsidiaries. These covenants may include but are not limited to maintenance of certain reserves, minimum levels of working capital and limitations on incurring additional indebtedness. Compliance with certain covenants may not be objectively determinable.

The following table summarizes the Company s subsidiary non-recourse debt in default as of December 31, 2006 and 2005.

Subsidiary	Primary Nature of Default	December 31, 2006 Default (in millions)	December 31, 2006 Net Assets	December 31, 2005 Default	December 31, 2005 Net Assets
Eden/Edes	Payment	$ 87	$ (74)	$ 98	$ (17)
Hefei	Payment	4	23	4	26
Kelanitissa (1)	Covenant	61	40		
Tisza II (2)	Material adverse change	93	138		
Ekibastuz	Covenant			3	68
Parana	Material adverse change			33	(77)
Total		$ 245		$ 138	

(1) Kelanitissa is in violation of a covenant under its $65 million credit facility because of a cross default to a material agreement for the plant. The outstanding debt balance as of December 31, 2006 was $61 million.

(2) Tisza II is in default as a consequence of the re-introduction of administrative price regulation in Hungary.

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

Principal payments required on non-recourse debt outstanding at December 31, 2006, are $1,453 million in 2007, $1,071 million in 2008, $686 million in 2009, $1,098 million in 2010, $932 million in 2011 and $6,315 million thereafter.

As of December 31, 2006, several AES subsidiaries had approximately $383 million of unused lines of credit available mainly as working capital facilities.

As of December 31, 2006 and 2005, approximately $761 million and $602 million, respectively, of restricted cash was maintained in accordance with certain covenants of the debt agreements, and these amounts were included within Restricted Cash and Debt Service Reserves and Other Deposits in the accompanying consolidated balance sheets.

Various lender and governmental provisions restrict the ability of the Company s subsidiaries to transfer their net assets to the parent company. Such restricted net assets of subsidiaries amounted to approximately $4.6 billion at December 31, 2006.

RECOURSE DEBT Recourse debt obligations are direct borrowings of the AES parent corporation.

On March 3, 2006, the Company redeemed all of its outstanding 8.875% Senior Subordinated Debentures due 2027 (approximately $115 million aggregate principal amount). The redemption was made pursuant to the optional redemption provisions of the indenture governing the Debentures. The Debentures were redeemed at a redemption price equal to 100% of the principal amount thereof, plus a make-whole premium determined in accordance with the terms of the indenture, plus accrued and unpaid interest up to the redemption date.

The Company entered into a $500 million senior unsecured credit facility agreement effective March 31, 2006. On May 1, 2006, the Company exercised its option to extend the total amount of the senior unsecured credit facility by an additional $100 million to a total of $600 million. At December 31, 2006, the Company had no outstanding borrowings under the senior unsecured credit facility. The Company had $373 million of letters of credit outstanding against the senior unsecured credit facility as of December 31, 2006. The credit facility is being used to support our ongoing share of construction obligations for AES Maritza East 1 and for general corporate purposes. AES Maritza East 1 is a coal-fired generation project that began construction in the second quarter of 2006.

The Company s senior secured bank facilities (Bank Facilities) include the senior secured term loan (Term Loan) of $200 million and a senior secured revolving credit facility (Revolving Credit Facility) with available borrowing up to $750 million. As of December 31, 2006, the Revolving Credit Facility accrues interest at LIBOR plus 1.50% and matures in 2010.

In December 2006, the Company exercised its right to increase the Revolving Credit Facility by $100 million to a total of $750 million. As of December 31, 2006, there were no outstanding borrowings against the revolving credit facility. The Company had $88 million of letters of credit outstanding against the Revolving Credit Facility and $662 million was available under the revolving credit facility.

Principal payments required on recourse debt outstanding at December 31, 2006 are $415 million in 2008, $467 million in 2009, $423 million in 2010, $674 million in 2011 and $2.8 billion thereafter.

Certain of the Company s obligations under the Bank Facilities are guaranteed by its direct subsidiaries through which the Company owns its interests in the Shady Point, Hawaii, Warrior Run and

Eastern Energy businesses. The Company s obligations under the Bank Facilities and Second Priority Senior Secured Notes are, subject to certain exceptions, secured by:

(i) all of the capital stock of domestic subsidiaries owned directly by the Company and 65% of the capital stock of certain foreign subsidiaries owned directly or indirectly by the Company; and

(ii) certain intercompany receivables, certain intercompany notes and certain intercompany tax sharing agreements.

The Bank Facilities are subject to mandatory prepayment as follows:

- Net cash proceeds from sales of assets of or equity interests in IPALCO, a Guarantor or any of their subsidiaries must be applied pro rata to repay the Term Loan using 60% of net cash proceeds, provided that the 60% shall be reduced to 50% when and if the parent s recourse debt to cash flow ratio is less than 5:1 and further provided that Lenders shall have the option to waive their pro rata redemption. In the case of sales of assets of or equity interests in IPALCO or any of its subsidiaries, asset sale net cash proceeds remaining after application to the Term Loan facility shall be used to reduce commitments under the Revolver, unless the supermajority of banks otherwise agree or unless the facilities are rated at least Ba1 from Moody s and AES s corporate credit rating is at least BB- from S&P.

The Bank Facilities contain customary covenants and restrictions on the Company s ability to engage in certain activities, including, but not limited to:

- limitations on other indebtedness, liens, investments and guarantees;

- restrictions on dividends and redemptions and payments of unsecured and subordinated debt and the use of proceeds;

- restrictions on mergers and acquisitions, sales of assets, leases, transactions with affiliates and off balance sheet and derivative arrangements; and

- financial and other reporting requirements.

The Bank Facilities also contain financial covenants requiring the Company to maintain certain financial ratios including:

- cash flow to interest coverage ratio, calculated quarterly, which provides that a minimum ratio of the Company s adjusted operating cash flow to the Company s interest charges related to recourse debt must be maintained at all times; and

- recourse debt to cash flow ratio, calculated quarterly, which provides that the ratio of the Company s total recourse debt to the Company s adjusted operating cash flow must not exceed a maximum at any time of calculation; and future borrowings and letter of credit issuances under the Bank Facilities will be subject to customary borrowing conditions, including the absence of an event of default and the absence of any material adverse change since December 31, 2003.

The terms of the Company s Second Priority Senior Secured Notes contain certain restrictive covenants, including limitations on the Company s ability to incur additional secured debt, pay dividends to stockholders, repurchase capital stock or make other restricted payments, incur additional liens, sell assets, enter into transactions with affiliates and enter into sale and leaseback transactions. The terms of the Company s Senior Unsecured Notes contain certain covenants including, without limitation, limitation on the Company s ability to incur liens and enter into sale and leaseback transactions.

TERM CONVERTIBLE TRUST SECURITIES During 1999, AES Trust III, a wholly owned special purpose business trust, issued 9 million of $3.375 Term Convertible Preferred Securities (TECONS) (liquidation value $50) for total proceeds of approximately $518 million and concurrently purchased

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approximately $518 million of 6.75% Junior Subordinated Convertible Debentures due 2029 (the 6.75% Debentures of the Company).

During 2000, AES Trust VII, a wholly owned special purpose business trust, issued 9.2 million of $3.00 TECONS (liquidation value $50) for total proceeds of approximately $460 million and concurrently purchased approximately $460 million of 6% Junior Subordinated Convertible Debentures due 2008 (the 6% Debentures and collectively with the 6.75% Debentures, the Junior Subordinated Debentures). The sole assets of AES Trust III and VII (collectively, the TECON Trusts) are the Junior Subordinated Debentures.

AES, at its option, can redeem the 6.75% Debentures which would result in the required redemption of the TECONS issued by AES Trust III, currently for $50.42 per TECON, reduced annually by $0.422 to a minimum of $50 per TECON. AES, at its option can redeem the 6% Debentures which would result in the required redemption of the TECONS issued by AES Trust VII, for $50.75 per TECONS as of December 31, 2006, reduced annually by $0.375 to a minimum of $50 per TECON. The TECONS must be redeemed upon maturity of the Junior Subordinated Debentures.

The TECONS are convertible into the common stock of AES at each holder s option prior to October 15, 2029 for AES Trust III and May 14, 2008 for AES Trust VII at the rate of 1.4216 and 1.0811 respectively, representing a conversion price of $35.171 and $46.25 per share, respectively.

Dividends on the TECONS are payable quarterly at an annual rate of 6.75% by AES Trust III and 6% by AES Trust VII. The Trusts are each permitted to defer payment of dividends for up to 20 consecutive quarters, provided that the Company has exercised its right to defer interest payments under the corresponding debentures or notes. During such deferral periods, dividends on the TECONS would accumulate quarterly and accrue interest, and the Company may not declare or pay dividends on its common stock.

AES Trust III and AES Trust VII are variable interest entities under FASB Interpretation No. 46, *Consolidation of Variable Interest Entities An Interpretation of ARB No. 51* (FIN 46). AES is not the primary beneficiary of either AES Trust III or AES Trust VII and accordingly, does not consolidate their results. AES s obligations under the Junior Subordinated Debentures and other relevant trust agreements, in aggregate, constitute a full and unconditional guarantee by AES of the TECON Trusts obligations under the trust securities issued by each respective trust.

9. DERIVATIVE INSTRUMENTS

AES utilizes derivative financial instruments to hedge interest rate risk, foreign exchange risk and commodity price risk. The Company utilizes interest rate swap, cap and floor agreements to hedge interest rate risk on floating rate debt. Most of AES s interest rate derivatives are designated and qualify as cash flow hedges. Currency forwards, options and swap agreements are utilized by the Company to hedge foreign exchange risk. The Company utilizes electric and fuel derivative instruments, including swaps, options, forwards and futures, to hedge the risk related to electricity sales and fuel purchases. Most of AES s electric and fuel derivatives are designated and qualify as cash flow hedges.

Certain derivatives are not designated as hedging instruments, primarily because they do not qualify for hedge accounting treatment as defined by SFAS No. 133. The purpose of these instruments is to economically hedge interest rate risk, foreign exchange risk or commodity price risk. However, certain features of these contracts, primarily the inclusion of written options, cause them to not qualify for hedge accounting.

Amounts recorded in accumulated other comprehensive loss, after income taxes, during the years ended December 31, 2006, 2005, and 2004, respectively are as follows:

December 31,	Balance, beginning of year (in millions)	Reclassification to earnings	Reclassification upon sale or disposal	Change in fair value	Balance, December 31
2006	$ (400)	$ (6)	$ (3)	$ 283	$ (126)
2005	(325)	153		(228)	(400)
2004	(291)	88	12	(134)	(325)

Approximately $29 million of the accumulated other comprehensive loss related to derivative instruments as of December 31, 2006 is expected to be recognized as an increase to income from continuing operations over the next twelve months. This estimate includes an estimated loss of $1 million, a gain of $38 million and a loss of $8 million related to foreign currency, commodity and interest rate instruments, respectively. The balance in accumulated other comprehensive loss related to derivative transactions will be reclassified into earnings as interest expense is recognized for hedges of interest rate risk, as depreciation is recorded for hedges of capitalized interest, as foreign currency transaction and translation gains and losses are recognized for hedges of foreign currency exposure, and as electric and gas sales and purchases are recognized for hedges of forecasted electric and fuel transactions.

The maximum length of time over which AES is hedging its exposure to variability in future cash flows for forecasted transactions, excluding forecasted transactions related to the payment of variable interest on existing financial instruments, is 24 years. For the years ended December 31, 2006, 2005, and 2004, gains (losses) of $3 million, $0, and $(7) million, respectively, were reclassified into earnings as a result of the discontinuance of a cash flow hedge because it was probable that the forecasted transaction would not occur. For the years ended December 31, 2006 and 2005 no fair value hedges were discontinued. The Company recognized after-tax gains of $18 million, $20 million, and $2 million related to the ineffective portion of derivatives qualifying as cash flow and fair value hedges for the years ended December 31, 2006, 2005, and 2004, respectively. The ineffective portion is recognized as interest income or expense for interest rate hedges, foreign currency gains or losses on foreign currency hedges, and non-regulated revenue or non-regulated cost of sales for commodity hedges.

After-tax losses related to the changes in fair value of derivatives that do not qualify for hedge accounting were $12 million, $69 million and $17 million for the years ended December 31, 2006, 2005 and 2004, respectively. The after-tax losses include embedded foreign currency derivatives, interest rate swaps and options, and embedded commodity derivatives. Gains or losses on derivatives that do not qualify for hedge accounting are recognized as interest income or expense for interest rate derivatives, foreign currency gains or losses on foreign currency derivatives, and revenue or cost of sales for commodity derivatives. As of December 31, 2006 and 2005, derivative liabilities included in other current liabilities on the Consolidated Balance Sheets were $68 million and $283 million, respectively.

10. COMMITMENTS

OPERATING LEASES As of December 31, 2006, the Company was obligated under long-term non-cancelable operating leases, primarily for office rental and site leases. Rental expense for lease commitments under these operating leases for the years ended December 31, 2006, 2005 and 2004 was $17 million, $12 million and $10 million, respectively.

The table below sets forth the future minimum lease commitments under these operating leases at December 31, 2006 for 2007 through 2011 and thereafter:

December 31,	**Future Commitments for Operating Leases (in millions)**
2007	$ 17
2008	16
2009	14
2010	11
2011	11
Thereafter	109
Total	$ 178

CAPITAL LEASES Several AES subsidiaries lease operating and office equipment and vehicles. These leases have been recorded as capital leases in Property, Plant and Equipment within Electric generation and distribution assets. The gross value of the leased assets for the years ended December 31, 2006 and 2005 was $13 million and $9 million, respectively.

The following table is a schedule by years of future minimum lease payments under capital leases together with the present value of the net minimum lease payments at December 31, 2006 for 2007 through 2011 and thereafter:

December 31,	**Future Minimum Lease Payments (in millions)**
2007	$ 4
2008	3
2009	2
2010	1
2011	
Thereafter	
Total	10
Less: Imputed interest	2
Present value of total minimum lease payments	$ 8

SALE/LEASEBACK In May 1999, a subsidiary of the Company acquired six electric generating stations from New York State Electric and Gas (NYSEG). Concurrently, the subsidiary sold two of the plants to an unrelated third party for $666 million and simultaneously entered into a leasing arrangement with the unrelated party. This transaction has been accounted for as a sale/leaseback with operating lease treatment. Rental expense was $54 million for each of the years ended December 31, 2006, 2005 and 2004.

The following table summarizes the future minimum lease commitments under sale/leaseback arrangements at December 31, 2006 for 2007 through 2011 and thereafter:

December 31,	Future Minimum Lease Commitments (in millions)
2007	$ 63
2008	63
2009	63
2010	65
2011	69
Thereafter	993
Total	$ 1,316

CONTRACTS **Operating** subsidiaries of the Company have entered into contracts for the purchase of electricity from third parties. Purchases in the years ended December 31, 2006, 2005 and 2004 were approximately $1.2 billion, $1.1 billion and $1.0 billion, respectively.

The table below sets forth the future commitments under these electricity purchase contracts at December 31, 2006 for 2007 through 2011 and thereafter.

December 31,	Commitments for Electricity Purchase Contracts (in millions)
2007	$ 1,430
2008	1,603
2009	1,601
2010	1,771
2011	1,797
Thereafter	15,187
Total	$23,389

Operating subsidiaries of the Company have entered into various long-term contracts for the purchase of fuel subject to termination only in certain limited circumstances. Purchases in the years ended December 31, 2006, 2005 and 2004 were $644 million, $577 million and $510 million, respectively. The table below sets forth the future commitments under these fuel contracts as of December 31, 2006 for 2007 through 2011 and thereafter.

December 31,	Future Commitments for Fuel Contracts (in millions)
2007	$ 1,020
2008	1,047
2009	855
2010	796
2011	758
Thereafter	6,033
Total	$10,509

The Company s subsidiaries entered into other various long-term contracts. These contracts are mainly for construction projects, service and maintenance, transmission of electricity and other operation services.

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The table below sets forth the future commitments under these other purchase contracts as of December 31, 2006 for 2007 through 2011 and thereafter.

December 31,	Future Commitments for Other Purchase Contracts (in millions)
2007	$ 1,234
2008	697
2009	361
2010	147
2011	116
Thereafter	819
Total	$ 3,374

11. CONTINGENCIES

ENVIRONMENTAL The Company reviews its obligations as they relate to compliance with environmental laws, including site restoration and remediation. As of December 31, 2006, the Company has recorded liabilities of $12.8 million for projected environmental remediation costs. Due to the uncertainties associated with environmental assessment and remediation activities, future costs of compliance or remediation could be higher or lower than the amount currently accrued. Based on currently available information and analysis, the Company believes that it is possible that costs associated with such liabilities or as yet unknown liabilities may exceed current reserves in amounts that could be material but cannot be estimated as of December 31, 2006.

GUARANTEES, LETTERS OF CREDIT In connection with certain of its project financing, acquisition, and power purchase agreements, AES has expressly undertaken limited obligations and commitments, most of which will only be effective or will be terminated upon the occurrence of future events. In the normal course of business, AES and certain of its subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees, letters of credit and surety bonds. These agreements are entered into primarily to support or enhance the creditworthiness otherwise achieved by a subsidiary on a stand-alone basis, thereby facilitating the availability of sufficient credit to accomplish the subsidiaries intended business purposes.

The following table summarizes the company s contingent contractual obligations as of December 31, 2006.

Contingent contractual obligations	Amount (in millions)	Number of Agreements	Exposure Range for Each Agreement (in millions)
Guarantees	$ 533	32	<$1 - $100
Letters of credit under the Revolving Credit Facility	88	12	<$1 - $26
Letters of credit under the Senior Unsecured Credit Facility	373	8	<$1 - $333
Surety Bonds	1	1	$ 1
Total	$ 995	53	

Most of the contingent obligations primarily represent future performance commitments which the Company expects to fulfill within the normal course of business. Amounts presented in the above table represent the Company s current undiscounted exposure to guarantees and the range of maximum

undiscounted potential exposure to the Company as of December 31, 2006. Guarantee termination provisions vary from less than 1 year to greater than 20 years. Some result from the end of a contract period, assignment, asset sale, and change in credit rating or elapsed time. The amounts above include obligations made by the Company for the benefit of the lenders associated with the non-recourse debt of subsidiaries of $102 million.

The risks associated with these obligations include change of control, construction cost overruns, political risk, tax indemnities, spot market power prices, supplier support and liquidated damages under power purchase agreements for projects in development, under construction and operating. While the Company does not expect to be required to fund any material amounts under these contingent contractual obligations during 2007 or beyond that are not recorded on the balance sheet, many of the events which would give rise to such an obligation are beyond the Company s control. There can be no assurance that the Company would have adequate sources of liquidity to fund its obligations under these contingent contractual obligations if it were required to make substantial payments thereunder.

The Company pays letter of credit fees ranging from 1.63% to 2.64% per annum on the outstanding amounts.

In addition, several AES subsidiaries obtained letters of credit to guarantee certain requirements under debt or PPA agreements. As of December 31, 2006, $1.5 billion in letters of credit were outstanding.

LITIGATION The Company is involved in certain claims, suits and legal proceedings in the normal course of business. The Company has accrued for litigation and claims where it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. The Company believes, based upon information it currently possesses and taking into account established reserves for estimated liabilities and its insurance coverage, that the ultimate outcome of these proceedings and actions is unlikely to have a material adverse effect on the Company s financial statements. It is possible however, that some matters could be decided unfavorably to the Company, and could require the Company to pay damages or to make expenditures in amounts that could be material but cannot be estimated as of December 31, 2006.

In 1989, Centrais Elétricas Brasileiras S.A. (Eletrobrás) filed suit in the Fifth District Court in the State of Rio de Janeiro against Eletropaulo Eletricidade de São Paulo S.A. (EEDSP) relating to the methodology for calculating monetary adjustments under the parties financing agreement. In April 1999, the Fifth District Court found for Eletrobrás and, in September 2001, Eletrobrás initiated an execution suit in the Fifth District Court to collect approximately R$762 million (US$365 million) from Eletropaulo and a lesser amount from an unrelated company, Companhia de Transmissão de Energia Elétrica Paulista (CTEEP) (Eletropaulo and CTEEP were spun off of EEDSP pursuant to its privatization in 1998). Eletropaulo appealed and, in September 2003, the Appellate Court of the State of Rio de Janeiro ruled that Eletropaulo was not a proper party to the litigation because any alleged liability was transferred to CTEEP pursuant to the privatization. Subsequently, both Eletrobrás and CTEEP filed separate appeals to the Superior Court of Justice (SCJ). In June 2006, the SCJ reversed the Appellate Court s decision and remanded the case to the Fifth District Court for further proceedings, holding that Eletropaulo s liability, if any, should be determined by the Fifth District Court. Eletropaulo subsequently filed a motion for clarification of that decision, which was denied in February 2007. In April 2007 Eletropaulo filed appeals with the Special Court (the highest court within the SCJ) and the Supreme Court of Brazil. Eletrobras may resume the execution suit in the Fifth District Court at any time. If Eletrobras does so, Eletropaulo may be required to provide security in the amount of its alleged liability. Eletropaulo believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In September 1999, a state appellate court in Minas Gerais, Brazil, granted a temporary injunction suspending the effectiveness of a shareholders agreement between Southern Electric Brasil Participacoes, Ltda. (SEB) and the state of Minas Gerais concerning Companhia Energetica de Minas Gerais

(CEMIG), an integrated utility in Minas Gerais. The Company s investment in CEMIG is through SEB. This shareholders agreement granted SEB certain rights and powers in respect of CEMIG (Special Rights). In March 2000, a lower state court in Minas Gerais held the shareholders agreement invalid where it purported to grant SEB the Special Rights and enjoined the exercise of the Special Rights. In August 2001, the state appellate court denied an appeal of the decision and extended the injunction. In October 2001, SEB filed appeals against the state appellate court s decision with the Federal Superior Court and the Supreme Court of Justice. The state appellate court denied access of these appeals to the higher courts, and in August 2002 SEB filed interlocutory appeals against such denial with the Federal Superior Court and the Supreme Court of Justice. In December 2004, the Federal Superior Court declined to hear SEB s appeal. However, the Supreme Court of Justice is considering whether to hear SEB s appeal. SEB intends to vigorously pursue a restoration of the value of its investment in CEMIG by all legal means; however, there can be no assurances that it will be successful in its efforts. Failure to prevail in this matter may limit SEB s influence on the daily operation of CEMIG.

In August 2000, the Federal Energy Regulatory Commission (FERC) announced an investigation into the organized California wholesale power markets in order to determine whether rates were just and reasonable. Further investigations involved alleged market manipulation. FERC requested documents from each of the AES Southland, LLC plants and AES Placerita, Inc. AES Southland and AES Placerita have cooperated fully with the FERC investigation. AES Southland was not subject to refund liability because it did not sell into the organized spot markets due to the nature of its tolling agreement. AES Placerita is currently subject to refund liability of $588,000 plus interest for spot sales to the California Power Exchange from October 2, 2000 to June 20, 2001 (Refund Period). In September 2004, the U.S. Court of Appeals for the Ninth Circuit issued an order addressing FERC s decision not to impose refunds for the alleged failure to file rates, including transaction-specific data, for sales during 2000 and 2001 (September 2004 Decision). Although it did not order refunds, the Ninth Circuit remanded the case to FERC for a refund proceeding to consider remedial options. The Ninth Circuit has temporarily stayed the remand to FERC until June 13, 2007, so that settlement discussions may take place. AES Placerita and other parties are also seeking review of the September 2004 Decision in the U.S. Supreme Court. In addition, in August 2006 in a separate case, the Ninth Circuit confirmed the Refund Period, expanded the transactions subject to refunds to include multi-day transactions, expanded the potential liability of sellers to include any pre-Refund Period tariff violations, and remanded the matter to FERC (August 2006 Decision). The Ninth Circuit has temporarily stayed its August 2006 Decision until June 13, 2007, to facilitate settlement discussions. The August 2006 Decision may allow FERC to reopen closed investigations and order relief. Placerita made sales during the periods at issue in the September 2004 and August 2006 Decisions. Both appeals may be subject to further court review, and further FERC proceedings on remand would be required to determine potential liability, if any. Prior to the August 2006 Decision, AES Placerita s potential liability could have approximated $23 million plus interest. However, given the September 2004 and August 2006 Decisions, it is unclear whether AES Placerita s potential liability is less than or exceeds that amount. AES Placerita believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In November 2000, the Company was named in a purported class action along with six other defendants, alleging unlawful manipulation of the California wholesale electricity market, allegedly resulting in inflated wholesale electricity prices throughout California. The alleged causes of action include violation of the Cartwright Act, the California Unfair Trade Practices Act and the California Consumers Legal Remedies Act. In December 2000, the case was removed from the San Diego County Superior Court to the U.S. District Court for the Southern District of California. On July 30, 2001, the Court remanded the case to San Diego Superior Court. The case was consolidated with five other lawsuits alleging similar claims against other defendants. In March 2002, the plaintiffs filed a new master complaint in the consolidated action, which reasserted the claims raised in the earlier action and names the Company, AES Redondo Beach, LLC, AES Alamitos, LLC, and AES Huntington Beach, LLC as defendants. In May 2002, the case was removed by certain cross-defendants from the San Diego County Superior Court to the U.S. District Court for the Southern District of California. The plaintiffs filed a motion to remand the case to state court, which was granted on December 13, 2002. Certain defendants appealed aspects of that decision to the U.S. Court of Appeals for the Ninth Circuit. In December 2004, a panel of the Ninth Circuit issued an opinion affirming in part and reversing in part the decision of the District Court, and remanding the case to state court. In July 2005, defendants filed a demurrer in state court seeking dismissal of the case in its entirety. In October 2005, the court sustained the demurrer and entered an order of dismissal. In December 2005, plaintiffs filed a notice of appeal with the California Court of Appeal. In February 2007, the Court of Appeal affirmed the trial Court s judgment of dismissal. Plaintiffs did not appeal the Court of Appeal s decision.

In August 2001, the Grid Corporation of Orissa, India (Gridco), filed a petition against the Central Electricity Supply Company of Orissa Ltd. (CESCO), an affiliate of the Company, with the Orissa Electricity Regulatory Commission (OERC), alleging that CESCO had defaulted on its obligations as an OERC-licensed distribution company, that CESCO management abandoned the management of CESCO, and asking for interim measures of protection, including the appointment of an administrator to manage CESCO. Gridco, a state-owned entity, is the sole wholesale energy provider to CESCO. Pursuant to the OERC s August 2001 order, the management of CESCO was replaced with a government administrator who was appointed by the OERC. The OERC later held that the Company and other CESCO shareholders were not necessary or proper parties to the OERC proceeding. In August 2004, the OERC issued a notice to CESCO, the Company and others giving the recipients of the notice until November 2004 to show cause why CESCO s distribution license should not be revoked. In response, CESCO submitted a business plan to the OERC. In February 2005, the OERC issued an order rejecting the proposed business plan. The order also stated that the CESCO distribution license would be revoked if an acceptable business plan for CESCO was not submitted to, and approved by, the OERC prior to March 31, 2005. In its April 2, 2005 order, the OERC revoked the CESCO distribution license. CESCO has filed an appeal against the April 2, 2005 OERC order and that appeal remains pending in the Indian courts. In addition, Gridco asserted that a comfort letter issued by the Company in connection with the Company s indirect investment in CESCO obligates the Company to provide additional financial support to cover all of CESCO s financial obligations to Gridco. In December 2001, Gridco served a notice to arbitrate pursuant to the Indian Arbitration and Conciliation Act of 1996 on the Company, AES Orissa Distribution Private Limited (AES ODPL), and Jyoti Structures (Jyoti) pursuant to the terms of the CESCO Shareholders Agreement between Gridco, the Company, AES ODPL, Jyoti and CESCO (the CESCO arbitration). In the arbitration, Gridco appears to seek approximately $188.5 million in damages plus undisclosed penalties and interest, but a detailed alleged damages analysis has yet to be filed by Gridco. The Company has counterclaimed against Gridco for damages. An arbitration hearing with respect to liability was conducted on August 3 9, 2005 in India. Final written arguments regarding liability were submitted by the parties to the arbitral tribunal in late October 2005. A decision on liability has not yet been issued. Moreover, a petition remains pending before the Indian Supreme Court concerning fees of the third neutral arbitrator and the venue of future hearings with respect to the CESCO arbitration. The Company believes that it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In December 2001, a petition was filed by Gridco in the local India courts seeking an injunction to prohibit the Company and its subsidiaries from selling their shares in Orissa Power Generation Company Pvt. Ltd. (OPGC), an affiliate of the Company, pending the outcome of the above-mentioned CESCO arbitration. OPGC, located in Orissa, is a 420 MW coal-based electricity generation business from which Gridco is the sole off-taker of electricity. Gridco obtained a temporary injunction, but the District Court eventually dismissed Gridco s petition for an injunction in March 2002. Gridco appealed to the Orissa High Court, which in January 2005 allowed the appeal and granted the injunction. The Company has appealed the High Court s decision to the Supreme Court of India. In May 2005, the Supreme Court adjourned this matter until August 2005. In August 2005, the Supreme Court adjourned the matter again to await the award of the arbitral tribunal in the CESCO arbitration. The Company believes that it has meritorious claims and defenses and will assert them vigorously in these proceedings; however there can be no assurances that it will be successful in its efforts.

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

In April 2002, IPALCO Enterprises, Inc. (IPALCO), the pension committee for the Indianapolis Power & Light Company thrift plan (Pension Committee), and certain former officers and directors of IPALCO were named as defendants in a purported class action filed in the U.S. District Court for the Southern District of Indiana. In May 2002, an amended complaint was filed in the lawsuit. The amended complaint asserts that IPALCO and former members of the Pension Committee breached their fiduciary duties to the plaintiffs under the Employees Retirement Income Security Act by investing assets of the thrift plan in the common stock of IPALCO prior to the acquisition of IPALCO by the Company. In September 2003 the Court granted plaintiffs motion for class certification. In October 2003 the parties filed cross-motions for summary judgment on liability. In August 2005, the Court issued an order denying the summary judgment motions, but striking one defense asserted by defendants. A trial addressing only the allegations of breach of fiduciary duty began on February 21, 2006 and concluded on February 28, 2006. In March 2007, the Court issued a decision in favor of defendants and dismissed the lawsuit with prejudice. In April 2007, plaintiffs appealed the Court s decision to the U.S. Court of Appeals for the Seventh Circuit as to the former officers and directors of IPALCO, but not as to IPALCO or the Pension Committee.

In March 2003, the office of the Federal Public Prosecutor for the State of Sao Paulo, Brazil (MPF) notified AES Eletropaulo that it had commenced an inquiry related to the Brazilian National Development Bank (BNDES) financings provided to AES Elpa and AES Transgás and the rationing loan provided to Eletropaulo, changes in the control of Eletropaulo, sales of assets by Eletropaulo and the quality of service provided by Eletropaulo to its customers, and requested various documents from Eletropaulo relating to these matters. In July 2004, the MPF filed a public civil lawsuit in federal court alleging that BNDES violated Law 8429/92 (the Administrative Misconduct Act) and BNDES s internal rules by: (1) approving the AES Elpa and AES Transgás loans; (2) extending the payment terms on the AES Elpa and AES Transgás loans; (3) authorizing the sale of Eletropaulo s preferred shares at a stock-market auction; (4) accepting Eletropaulo s preferred shares to secure the loan provided to Eletropaulo; and (5) allowing the restructurings of Light Serviços de Eletricidade S.A. (Light) and Eletropaulo. The MPF also named AES Elpa and AES Transgás as defendants in the lawsuit because they allegedly benefited from BNDES s alleged violations. In June 2005, AES Elpa and AES Transgás presented their preliminary answers to the charges. In May 2006, the federal court ruled that the MPF could pursue its claims based on the first, second, and fourth alleged violations noted above. The MPF subsequently filed an interlocutory appeal seeking to require the federal court to consider all five alleged violations. Also, in July 2006, AES Elpa and AES Transgás filed an interlocutory appeal seeking to enjoin the federal court from considering any of the alleged violations. The MPF s lawsuit before the federal court has been stayed pending those interlocutory appeals. AES Elpa and AES Transgás believe they have meritorious defenses to the allegations asserted against them and will defend themselves vigorously in these proceedings; however, there can be no assurances that they will be successful in their efforts.

In May 2003, there were press reports of allegations that Light colluded with Enron in April 1998 in connection with the auction of Eletropaulo. Enron and Light were among three potential bidders for Eletropaulo. At the time of the transaction in 1998, AES owned less than 15% of Light s stock and shared representation in Light s management and Board with three other shareholders. In June 2003, the Secretariat of Economic Law of the Ministry of Justice of Brazil (SDE) issued a notice of preliminary investigation seeking information from a number of entities, including AES Brasil Energia, with respect to the allegations in the press reports. As AES Brasil Energia was incorrectly cited in the original complaint, in August 2003, AES Elpa responded on behalf of AES-affiliated companies and denied knowledge of these allegations. SDE began a follow-up administrative proceeding as reported in a notice published in October 2003. In response to SDE s official letters requesting explanations on the accusations, AES Elpa filed its defense in January 2004. In April 2005, AES Elpa responded to an SDE request for additional information. In June 2005, SDE dismissed the case because the statute of limitations had expired and its investigation had found no evidence supporting the allegations. Subsequently, the case was sent to the Administrative Council for Economic Defense (CADE), the Brazilian antitrust authority, for final review of the decision. Furthermore, the São Paulo s State Public Attorney's Office and the Federal Public Attorney s Office issued separate opinions concluding that the case should be dismissed because the statute of limitations had expired. The São Paulo s State Public Attorney s Office further found that there was no evidence of any wrongdoing. These opinions were ratified by the relevant state and federal courts. In January 2007, CADE decided by unanimous vote of its Counselors to close the case.

AES Florestal, Ltd. (Florestal), had been operating a pole factory and had other assets, including a wooded area known as Horto Renner , in the State of Rio Grande do Sul, Brazil (collectively, Property). AES Florestal had been under the control of AES Sul since October 1997, when AES Sul was created pursuant to a privatization by the Government of the State of Rio Grande do Sul. After it came under the control of AES Sul, AES Florestal performed an environmental audit of the entire operational cycle at the pole factory. The audit discovered 200 barrels of solid creosote waste and other contaminants at the pole factory. The audit concluded that the prior operator of the pole factory, Companhia Estadual de Energia Elétrica (CEEE), had been using those contaminants to treat the poles that were manufactured at the factory. AES Sul and AES Florestal subsequently took the initiative of communicating with Brazilian authorities, as well as CEEE, about the adoption of containment and remediation measures. The Public Attorney s Office has initiated a civil inquiry (Civil Inquiry n. 24/05) to investigate potential civil liability and has requested that the police station of Triunfo institute a Police Investigation (IP number 1041/05) to investigate potential criminal liability regarding the contamination at the pole factory. The environmental agency (FEPAM) has also started a procedure (Procedure n. 088200567/05 9) to analyze the measures that shall be taken to contain and remediate the contamination. The measures that must be taken by AES Sul and CEEE are still under discussion. Also, in March 2000, AES Sul filed suit against CEEE in the 2nd Court of Public Treasure of Porto Alegre seeking to register in AES Sul s name the Property that it acquired through the privatization but that remained registered in CEEE s name. During those proceedings, a court-appointed expert acknowledged that AES Sul had paid for the Property but opined that the Property could not be re-registered in AES Sul s name because CEEE did not have authority to transfer the Property through the privatization. Therefore, AES waived its claim to re-register the Property and asserted a claim to recover the amounts paid for the Property. That claim is pending. Moreover, in February 2001, CEEE and the State of Rio Grande do Sul brought suit in the 7th Court of Public Treasure of Porto Alegre against AES Sul, AES Florestal, and certain public agents that participated in the privatization. The plaintiffs alleged that the public agents unlawfully transferred assets and created debts during the privatization. In 2005, the control of AES Florestal was transferred from AES Sul to AES Guaíba II in accordance with Federal Law n. 10848/04. AES Florestal subsequently became a non-operative company. In November 2005, the Court ruled that the Property must be returned to CEEE. Subsequently, AES Sul and CEEE jointly possessed the Property for a time, but CEEE has had sole possession of Horto Renner since September 2006 and of the rest of the Property since April 2006.

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

In April 2004, BNDES filed a collection suit against SEB to obtain the payment of R$3.3 billion (US$1.6 billion) under the loan agreement between BNDES and SEB, the proceeds of which were used by SEB to acquire shares of CEMIG. In May 2004, the 15th Federal Circuit Court ordered the attachment of SEB's CEMIG shares, which were given as collateral for the loan, as well as dividends paid by CEMIG to SEB. At the time of the attachment, the shares were worth approximately R$762 million (US$247 million). In March 2007, the dividends were determined to be worth approximately R$423 million (US$198 million). SEB s defense was ruled groundless by the Circuit Court in December 2006. In January 2007, SEB filed an appeal to the relevant Federal Court of Appeals. BNDES may attempt to seize the attached CEMIG shares and withdraw the dividends at any time. SEB believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

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

In October 2004, Raytheon Company (Raytheon) filed a lawsuit against AES Red Oak LLC (Red Oak) in the Supreme Court of the State of New York, County of New York. The complaint purports to allege claims for breach of contract, fraud, interference with contractual rights and equitable relief relating to the construction and/or performance of the Red Oak project, an 800 MW combined cycle power plant in Sayreville, New Jersey. The complaint seeks the return of approximately $30 million that was drawn by Red Oak under a letter of credit that was posted by Raytheon for the construction and/or performance of the Red Oak project. Raytheon also seeks $110 million in purported additional expenses allegedly incurred by Raytheon in connection with the guaranty and construction agreements entered with Red Oak. In December 2004, Red Oak answered the complaint and filed breach of contract and fraud counterclaims against Raytheon. The Court subsequently ordered Red Oak to pay Raytheon approximately $16.3 million plus interest, which sum allegedly represented the amount of the letter of credit draw that had yet to be utilized for performance/construction issues. The Court also dismissed Red Oak s fraud claims, which decision was upheld on appeal. The parties have stipulated that Red Oak may assert claims for performance/construction issues if it has incurred costs on such claims. In May 2005, Raytheon filed a related action against Red Oak in the Superior Court of Middlesex County, New Jersey, seeking to foreclose on a construction lien in the amount of approximately $31 million on property allegedly owned by Red Oak. Red Oak filed its answer and counterclaim in October 2005. Red Oak believes it has meritorious claims and defenses and will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In January 2005, the City of Redondo Beach (City) of California issued an assessment against Williams Power Co., Inc., (Williams) and AES Redondo Beach, LLC (AES Redondo), an indirect subsidiary of the Company, for approximately $71.7 million in allegedly overdue utility users tax (UUT), interest, and penalties relating to the natural gas used at AES Redondo s power plant from May 1998 through September 2004 to generate electricity. In September 2005, the City Tax Administrator held AES Redondo and Williams jointly and severally liable for approximately $56.7 million in UUT, interest, and penalties. In October 2005, AES Redondo and Williams filed respective appeals with the City Manager, who appointed a Hearing Officer to decide the appeal. In December 2006, the Hearing Officer overturned the City s assessment against AES Redondo (but not Williams). In December 2006, Williams filed a petition for writ of mandate with Los Angeles Superior Court concerning the Hearing Officer s decision. Williams later prepaid $56.7 million to the City in order to continue litigating its petition, pursuant to a court order, and filed an amended petition. In March 2007, the City filed a petition for writ of mandate with the Superior Court concerning the Hearing Officer s decision as to AES Redondo. In addition, in July 2005, AES Redondo filed a lawsuit in Superior Court seeking a refund of UUT paid since February 2005, and an order that the City cannot charge AES Redondo UUT going forward. Williams later filed a similar complaint that was related to AES Redondo s lawsuit. After authorizing limited discovery on disputed jurisdictional and other issues, including whether AES Redondo and Williams must prepay to the City any allegedly owed UUT prior to judicially challenging the merits of the UUT, the Court stayed the case in

December 2006. Furthermore, since December 2005, the Tax Administrator has periodically issued UUT assessments against AES Redondo and Williams for allegedly overdue UUT on the gas used at the power plant since October 2004 (New UUT Assessments). AES Redondo has objected to those and any future UUT assessments. The Tax Administrator has stated that AES Redondo s objections are moot in light of his September 2005 decision. The Tax Administrator has not scheduled a hearing on the New UUT assessments, but has indicated that if there is one he will only address the amount of those assessments, not the merits of them. AES Redondo believes that it has meritorious claims and defenses, and it will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In February 2006, the local Kazakhstan tax commission imposed an environmental fine on Maikuben West mine, for alleged unauthorized disposal of overburden in the mine during 2003 and 2004. On November 23, 2006, Maikuben West paid a fine of approximately $2.8 million in connection with this matter.

In March 2006, the Government of the Dominican Republic and Secretariat of State of the Environment and Natural Resources of the Dominican Republic (collectively, Plaintiffs) filed a complaint in the U.S. District Court for the Eastern District of Virginia against The AES Corporation, AES Aggregate Services, Ltd., AES Atlantis, Inc., and AES Puerto Rico, LP (collectively, AES Defendants), and unrelated parties, Silver Spot Enterprises and Roger Charles Fina. In June 2006, the Plaintiffs filed a substantially similar amended complaint against the defendants, alleging that the defendants improperly disposed of coal ash waste in the Dominican Republic, and that the alleged waste was generated at AES Puerto Rico s power plant in Guayama, Puerto Rico. Based on these allegations, the amended complaint asserts seven claims against the defendants: violation of 18 U.S.C. §§ 1961 68, the Racketeer Influenced and Corrupt Organizations Act (RICO Act); conspiracy to violate section 1962(c) of the RICO Act; civil conspiracy to violate the Foreign Corrupt Practices Act (FCPA) and other unspecified laws concerning bribery and waste disposal; aiding and abetting the violation of the FCPA and other unspecified laws concerning bribery and waste disposal; violation of unspecified nuisance law; violation of unspecified product liability law; and violation of 28 U.S.C. § 1350, the Alien Tort Statute (which the Plaintiffs later voluntarily dismissed without prejudice). While the Plaintiffs did not quantify their alleged damages in their amended complaint, in their discovery responses they claimed to be seeking at least $28 million in alleged compensatory damages and $196 million in alleged punitive damages from the defendants. In February 2007 the Plaintiffs and the AES Defendants settled their dispute. The Court has entered a joint stipulation dismissing the Plaintiffs claims against the AES Defendants with prejudice.

AES Eastern Energy voluntarily disclosed to the New York State Department of Environmental Conservation (NYSDEC) and the U.S. Environmental Protection Agency (EPA) on November 27, 2002 that nitrogen oxide (NOx) exceedances appear to have occurred on October 30 and 31, and November 18 and 10 of 2002. The exceedances were discovered through an audit by plant personnel of the Plant s NOx Reasonably Available Control Technology (RACT) tracking system. Immediately upon the discovery of the exceedances, the selective catalytic reduction (SCR) at the Somerset plant was activated to reduce NOx emissions. AES Eastern Energy learned of a notice of violation (the NOV) issued by the NYSDEC for the NOx RACT exceedances through a review of the November 2004 release of the EPA s Enforcement and Compliance History (ECHO) database. However, AES Eastern Energy has not yet seen the NOV from the NYSDEC. AES Eastern Energy is currently negotiating with NYSDEC concerning this matter. On November 13, 2006 AES Eastern Energy paid a fine of $263,200 and entered into a consent decree with NYSDEC, addressing these matters.

In June 2006, AES Ekibastuz was found to have breached a local tax law by failing to obtain a license for use of local water for the period of January 1, 2005 through October 3, 2005, in a timely manner. As a result, an additional permit fee was imposed, brining the total permit fee to approximately $135,000. The company has appealed this decision to the Supreme Court.

In October 2006, the Constitutional Chamber of the Venezuelan Supreme Court decided that it would review a lawsuit filed in 2000 by certain Venezuelan citizens alleging that the Company s acquisition of a controlling stake in C.A. La Electricidad de Caracas (EDC) in 2000 was void because the acquisition had not been approved by the Venezuelan National Assembly. AES has been notified of the Supreme Court s decision to review the lawsuit. AES believes that it complied with all existing laws with respect to the acquisition and that there are meritorious defenses to the allegations in this lawsuit; however, there can be no assurance that it will prevail in this lawsuit.

In October 2006, CDEEE began making public statements that it intends to seek to compel the renegotiation and/or rescission of long-term power purchase agreements with certain power-generation companies in the Dominican Republic. Although the details concerning CDEEE s statements are unclear and no formal government action has been taken, AES owns certain interests in three power-generation companies in the country (AES Andres, Itabo, and Dominican Power Partners) that could be adversely impacted by any actions taken by or at the direction of CDEEE.

In February 2007, the Competition Committee of the Ministry of Industry and Trading of the Republic of Kazakhstan initiated administrative proceedings against two hydro plants under AES concession, Ust-Kamenogorsk HPP and Shulbinsk HPP (collectively, Hydros), for allegedly using Nurenergoservice LLP to increase power prices for customers in alleged violation of Kazakhstan s antimonopoly laws. The Competition Committee subsequently issued orders directing the Hydros to pay approximately 4.3 billion KZT (US$35 million) in damages and fines. In April 2007 the Hydros appealed those orders to the local courts. In addition, Nurenergoservice has been informed that it will be ordered by the Competition Committee to pay approximately 2 billion KZT (US$15 million) for alleged antimonopoly violations. In related proceedings, in March 2007 the local financial police initiated criminal proceedings against the General Director and the Finance Director of the Hydros. Those proceedings were later terminated pursuant to a settlement. The Hydros and Nurenergoservice believe they have meritorious defenses and will assert them vigorously; however, there can be no assurances that they will be successful in their efforts.

12. BENEFIT PLANS

DEFINED CONTRIBUTION PLAN The Company sponsors one defined contribution plan, qualified under section 401 of the Internal Revenue Code, which is available to eligible AES employees. The plan provides for Company matching contributions in Company stock, other Company contributions at the discretion of the Compensation Committee of the Board of Directors in Company stock, and discretionary tax deferred contributions from the participants. Participants are fully vested in their own contributions and the Company s matching contributions. Participants vest in other Company contributions ratably over a five-year period ending on the 5th anniversary of their hire date. Company contributions to the plans were approximately $21 million, $17 million, and $16 million for the years ended December 31, 2006, 2005, and 2004, respectively.

DEFINED BENEFIT PLANS Certain of the Company s subsidiaries have defined benefit pension plans covering substantially all of their respective employees. Pension benefits are based on years of credited service, age of the participant and average earnings. Of the twenty-seven defined benefit plans, three are at U.S. subsidiaries and the remaining plans are at foreign subsidiaries.

The Company adopted SFAS 158, effective December 31, 2006, which requires recognition of an asset or liability in the balance sheet reflecting the funded status of pension and other postretirement benefits plans with current-year changes in the funded status recognized in stockholders equity. The Company recorded a cumulative adjustment, as described in the table below, to adopt the recognition provisions of SFAS No. 158 as of December 31, 2006. AES will adopt the measurement date provisions of the standard for the fiscal year ending December 31, 2008.

	Before Adoption of SFAS 158 12/31/06	Effect of FAS 158 Adoption	After Adoption 12/31/06
Assets			
Pension assets	$ 25	$ 8	$ 33
Regulatory assets		146	146
Liabilities			
Pension obligations	911	(70)	841
Stockholders' Equity			
Accumulated other comprehensive income	319	(145)	174

The following table summarizes the Company s change in benefit obligation, both domestic and foreign, as of December 31, 2006 and 2005.

	December 31, 2006 U.S. (in millions)	Foreign	2005 U.S.	Foreign
CHANGE IN BENEFIT OBLIGATION:				
Benefit obligation at beginning of year	$ 524	$ 2,794	$ 475	$ 2,410
Service cost	6	7	5	5
Interest cost	30	356	28	297
Employee Contributions		17		15
Plan amendments	5		7	3
Plan curtailments				(1)
Benefits paid	(30)	(287)	(30)	(251)
Net transfer in/(out)		5		
Effect of plan combinations				20
Actuarial loss	20	53	39	20
Effect of foreign currency exchange rate change		268		276
Benefit obligation as of December 31	$ 555	$ 3,213	$ 524	$ 2,794

The following table summarizes the company s change in plan assets, both domestic and foreign, as of December 31, 2006 and 2005.

	December 31, 2006 U.S. (in millions)	Foreign	2005 U.S.	Foreign
CHANGE IN PLAN ASSETS:				
Fair value of plan assets at beginning of year	$ 372	$ 1,958	$ 354	$ 1,541
Actual return on plan assets	40	440	27	261
Employer contributions	40	212	21	209
Employee contributions		17		16
Benefits paid	(30)	(286)	(30)	(251)
Adjustments				
Effect of foreign currency exchange rate change		197		182
Fair value of plan assets as of December 31	$ 422	$ 2,538	$ 372	$ 1,958

The following table summarizes the company s reconciliation of funded status, both domestic and foreign, as of December 31, 2006 and 2005.

	December 31, 2006 U.S. (in millions)	Foreign	2005 U.S.	Foreign
RECONCILIATION OF FUNDED STATUS				
Fair value of plan assets	$ 422	$ 2,538	$ 372	$ 1,958
Benefits obligations	555	3,213	524	2,794
Funded status	(133)	(675)	(152)	(836)
Unrecognized transition asset				(11)
Unrecognized prior service cost			22	6
Unrecognized net actuarial loss			118	286
Net amount recognized at end of year	$ (133)	$ (675)	$ (12)	$ (555)

The following table summarizes the amounts recognized on the consolidated balance sheets, both domestic and foreign, as of December 31, 2006 and 2005.

	December 31, 2006 U.S. (in millions)	Foreign	2005 U.S.	Foreign
AMOUNTS RECOGNIZED ON THE CONSOLIDATED BALANCE SHEETS				
Intangible asset	$	$	$ 22	$ 1
Accrued benefit liability			(152)	(861)
Accumulated other comprehensive income			118	257
Non-current assets		33		
Accrued benefit liability current		(4)		
Accrued benefit liability long-term	(133)	(704)		
Equity of minority shareholders				48
Net amount recognized at end of year	$ (133)	$ (675)	$ (12)	$ (555)

The following table summarizes the company s accumulated benefit obligation, both domestic and foreign, as of December 31, 2006 and 2005.

	December 31, 2006 U.S.	Foreign	2005 U.S.	Foreign
	(in millions)			
Accumulated Benefit Obligation	$ 551	$ 3,172	$ 520	$ 2,757
Information for pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	$ 555	$ 3,044	$ 524	$ 2,698
Accumulated benefit obligation	551	3,024	520	2,663
Fair value of plan assets	422	2,343	372	1,839
Information for pension plans with a projected benefit obligation in excess of plan assets:				
Projected benefit obligation	$ 555	$ 3,087	$ 524	$ 2,698
Fair value of plan assets	422	2,379	372	1,839

All but six of the Company s subsidiaries use a December 31 measurement date. The remaining six subsidiaries use either a November 30, October 31 or September 30 measurement date.

The table below demonstrates the significant weighted average assumptions used in the calculation of benefit obligation and net periodic benefit cost, both domestic and foreign, as of December 31, 2006 and 2005.

	December 31, 2006 U.S.	Foreign	2005 U.S.	Foreign
Benefit Obligation:				
Discount rates	5.64 %	11.73 %	5.82 %	12.43 %
Rates of compensation increase	4.75 %	6.98 %	4.75 %	6.96 %
Periodic Benefit Cost:				
Discount rate	5.82 %	12.43 %	5.98 %	11.98 %
Expected long-term rate of return on plan assets	8.00 %	12.27 %	8.00 %	11.81 %
Rate of compensation increase	4.75 %	6.96 %	4.75 %	6.97 %

A subsidiary of the Company has a defined benefit obligation of $523 million and $494 million at December 31, 2006 and 2005, respectively, and uses salary bands to determine future benefit costs rather than a rate of compensation increases. Rates of compensation increases in the table above do not include amounts related to this specific defined benefit plan.

The Company establishes its estimated long-term return on plan assets considering various factors, which include the targeted asset allocation percentages, historic returns, and expected future returns.

The following table summarizes the components of the net periodic benefit cost, both domestic and foreign, for the years ended December 31, 2004 through 2006.

Components of Net Periodic Benefit Cost:	December 31, 2006 U.S. (in millions)	2006 Foreign	2005 U.S.	2005 Foreign	2004 U.S.	2004 Foreign
Service cost	$ 6	$ 7	$ 5	$ 5	$ 4	$ 4
Interest cost	30	356	28	297	27	232
Expected return on plan assets	(29)	(255)	(29)	(194)	(28)	(133)
Amortization of initial net asset		(3)	(1)	(3)	(1)	(3)
Amortization of prior service cost	2		2		2	
Amortization of net loss	5	2	3	5	4	8
Total pension cost	$ 14	$ 107	$ 8	$ 110	$ 8	$ 108

For the years ended December 31, 2006, 2005, and 2004, $(102) million (prior to the adjustment for the adoption of SFAS No. 158), $(6) million, and $18 million, respectively, were included in other comprehensive income arising from a change in the additional minimum pension liability.

The following table summarizes the amounts reflected in Accumulated Other Comprehensive Income on the Consolidated Balance Sheet as of December 31, 2006 that have not yet been recognized as components of net periodic benefit cost.

	December 31, 2006 Accumluated Other Comprehensive Income U.S. (in millions)	Foreign	Amounts expected to be reclassified to earnings in next fiscal year U.S.	Foreign
Initial net transition asset	$	$ 10	$	$ 3
Prior service cost		(6)		
Unrecognized net actuarial loss		(178)		(2)
Total	$	$ (174)	$	$ 1

The following table summarizes the company s target allocation for 2007 and pension plan asset allocation, both domestic and foreign, as of December 31, 2006 and 2005.

Asset Category	Target Allocations U.S.	Foreign	Percentage of Plan Assets as of December 31, 2006 U.S.	2006 Foreign	2005 U.S.	2005 Foreign
Equity Securities	58% - 68%	23% - 33%	67.40 %	28.97 %	62.79 %	23.68 %
Debt Securities	28% - 38%	60% - 69%	25.04 %	64.11 %	33.45 %	71.75 %
Real Estate	0% - 5%	0% - 5%	2.89 %	2.18 %	3.76 %	2.95 %
Other	0% - 0%	3% - 8%	4.67 %	4.75 %	0.00 %	1.62 %
Total pension cost			100.00 %	100.00 %	100.00 %	100.00 %

The U.S. Plans seek to achieve the following long-term investment objectives:

- Maintenance of sufficient income and liquidity to pay retirement benefits and other lump sum payments;
- Long-term rate of return in excess of the annualized inflation rate;
- Long-term rate of return (net of relevant fees that meet or exceed the assumed actuarial rate);

- Long-term competitive rate of return on investments, net of expenses, that is equal to or exceeds various benchmark rates.

Consistent with the above, the allocation is reviewed intermittently to determine a suitable asset allocation which seeks to control risk through portfolio diversification and takes into account, among possible other factors, the above-stated objectives, in conjunction with current funding levels, cash flow conditions and economic and industry trends.

The investment strategy of the foreign plans seeks to maximize return on investment while minimizing risk. Our assumed asset allocation uses a lower exposure to equities to closely match market conditions and near term forecasts.

The following table summarizes the scheduled cash flows for U.S. and foreign expected employer contributions and expected future benefit payments, both domestic and foreign.

	U.S.	**Foreign**
	(in millions)	
Expected employer contribution in 2007	$ 3	$ 123
Expected benefit payments for fiscal year ending:		
2007	30	289
2008	31	298
2009	31	309
2010	32	460
2011	33	331
2012 - 2016	183	1,839

13. FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value of current financial assets, current financial liabilities, and debt service reserves and other deposits are estimated to be equal to their reported carrying amounts. The fair value of non-recourse debt, excluding capital leases, is estimated differently based upon the type of loan. For variable rate loans, carrying value approximates fair value. For fixed rate loans, the fair value is estimated using quoted market prices or discounted cash flow analyses. The fair value of interest rate swap, cap and floor agreements, foreign currency forwards and swaps, and energy derivatives is the estimated net amount that the Company would receive or pay to terminate the agreements as of the balance sheet date.

The estimated fair values of the Company s assets and liabilities have been determined using available market information. The estimates are not necessarily indicative of the amounts the Company could realize in a current market exchange. The use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts.

The following table summarizes the estimated fair values of the Company s short-term investments, debt and derivative financial instruments, as of December 31, 2006 and 2005.

	December 31, 2006 Current Carrying Amount	Noncurrent Carrying Amount	Fair Value	2005 Current Carrying Amount	Noncurrent Carrying Amount	Fair Value
			(in millions)			
Assets:						
Investments	$ 640	$ 47	$ 687	$ 199	$	$ 199
Energy derivatives	111	212	323	29	154	183
Foreign currency forwards and swaps	20	9	29			
Interest rate swaps	2	2	4	2	3	5
Stock warrants		5	5			
Liabilities:						
Non-recourse debt	$ 1,453	$ 10,102	$ 11,987	$ 1,447	$ 10,638	$ 12,925
Recourse debt		4,790	5,050	200	4,682	5,139
Energy derivatives	14	56	70	204	123	327
Foreign currency forwards and swaps	34	16	50	48	57	105
Interest rate swaps	19	82	101	27	101	128
Interest rate caps and floors	1	10	11	3	14	17

Amounts in the table above include the carrying amount and fair value of financial instruments of discontinued operations and assets held for sale.

The fair value estimates presented herein are based on pertinent information as of December 31, 2006 and 2005. The Company is not aware of any factors that would significantly affect the estimated fair value amounts since December 31, 2006.

14. STOCKHOLDERS EQUITY

SHARES ISSUED FOR DEBT

During 2004, the Company issued 19.7 million shares of common stock at an average price of $8.52 per share in exchange for approximately $165 million in Senior Subordinated Notes. This resulted in a gain on retirement of debt of approximately $5 million for the year ended December 31, 2004.

SALE OF SUBSIDIARY STOCK AND BRASILIANA RESTRUCTURING

On December 22, 2003, the Company concluded negotiations with the Brazilian National Development Bank (BNDES) and its wholly owned subsidiary, BNDES Participações S.A. (BNDESPAR), to restructure the outstanding indebtedness of the Company s Brazilian subsidiaries AES Transgas and AES Elpa, the holding companies of AES Eletropaulo (BNDES Debt Restructuring). On January 19, 2004 and on January 23, 2004, approvals were received on the BNDES Debt Restructuring from ANEEL and the Brazilian Central Bank, respectively. The transaction became effective on January 30, 2004 after the required approvals were obtained and a payment of $90 million was made by AES to BNDES.

Under the BNDES Debt Restructuring, all of the Company s equity interests in AES Eletropaulo, AES Uruguaiana Empreendimentos Ltda. (AES Uruguaiana) and AES Tietê S.A. (AES Tietê) were transferred to Brasiliana Energia, S.A. (Brasiliana), a holding company created for the debt restructuring. The debt at AES Elpa and AES Transgas was also transferred to Brasiliana.

In exchange for the termination of $863 million of outstanding Brasiliana debt and accrued interest during 2004, the Brazilian National Development Bank (BNDES) received $90 million in cash, 53.85% ownership of Brasiliana and a one-year call option (Sul Option) to acquire a 53.85% ownership interest of Sul. The Sul Option, which would require the Company to contribute its equity interest in Sul to Brasiliana, became exercisable on December 22, 2005. The debt refinancing was accounted for as a modification of a debt instrument; therefore, the $20 million of face value of remaining debt due in excess of carrying value will be amortized using the effective interest rate method over the life of the debt.

To effect the new ownership structure, Brasiliana issued 50.01% of its common shares to AES and the remainder to BNDES. It also issued a majority of its non-voting preferred shares to BNDES. As a result, BNDES effectively owns 53.85% of the total capital of Brasiliana. Pursuant to the shareholders agreement, AES controls Brasiliana through its ownership of a majority of the voting shares of the company.

As a result of the stock issuance, AES recorded minority interest of $181 million for BNDES s share of Brasiliana. In addition, the estimated fair value of the Sul Option of $37 million was recorded as a liability and was marked-to-market to reflect the changes in the underlying value of AES Sul, prior to BNDES s exercise or the expiration of its call option.

AES treated the issuance of new shares in Brasiliana to BNDES as a capital transaction in accordance with SAB 51. The net gain of $482 million has been reported as an adjustment to AES s additional paid-in capital on the accompanying consolidated balance sheet.

In June 2006, BNDES and AES reached an agreement to terminate the Sul Option in exchange for the transfer of another wholly owned AES subsidiary, AES Infoenergy Ltda. to Brasiliana and $15 million in cash. The agreement closed on August 15, 2006 resulting in a gain on sale of investment of $9 million, net of income taxes of $1 million, including the extinguishment of the Sul Option.

Starting in late September 2006, a consolidated AES subsidiary, Brasiliana, entered into a series of transactions to repay debt issued by Brasiliana which was held by BNDES, a Brazilian governmental agency, and to refinance certain other debts in the ownership chain of Brasiliana.

In September 2006, Brasiliana s wholly owned subsidiary, Transgás, sold 13.76 billion preferred class-B shares, representing 33% economic ownership, in Eletropaulo, a regulated electric utility in Brazil. The preferred class-B shares hold no voting rights. As a result, there was no change in Brasiliana s voting interest in Eletropaulo, and Brasiliana continues to control Eletropaulo. Brasiliana received approximately $522 million in net proceeds on the sale of its shares on the open market, at a price per share of Brazilian real $.0085 (approximately $.04/share). On October 5, 2006, the over-allotment option (2.064 billion shares, or 5% ownership in Eletropaulo) associated with the secondary offering was exercised, at a price per share of Brazilian real $.0085 (approximately $.04/share). Proceeds from the over-allotment option totaled $80 million.

As a result of these transactions, Brasiliana s economic ownership in Eletropaulo was reduced from 73% to 35% and therefore AES s economic ownership in Eletropaulo was reduced from 34% to 16%. AES continues to control and consolidate Eletropaulo as a result of its 50.01% voting interest in Brasiliana s successor company, which continues to own a 74% voting interest in Eletropaulo, in the form of common shares and preferred class-A shares.

Brasiliana entered into the following debt restructuring transactions to reduce leverage, eliminate U.S. dollar denominated debt and eliminate restrictive covenants (including an existing cash sweep) that prevented the payment of dividends from Brasiliana to its shareholders:

- On October 2, 2006, Brasiliana repaid in full $608 million in principal and accrued interest on debt held by BNDES;

- On October 30, 2006, the successor to Brasiliana, Companhia Brasiliana de Energia, repaid in full $94 million of principal and accrued interest in addition to a prepayment premium of $2 million, and;

- On November 3, 2006, AES IHB Ltd., a wholly owned subsidiary in the Brasiliana ownership chain, repaid in full $280 million of principal and accrued interest in addition to a prepayment premium of $42 million.

These debts were repaid prior to the scheduled maturity date and were funded primarily by the sale of the Eletropaulo preferred class-B shares held by Transgás and the issuance of $373 million of Brazilian real denominated debt on October 30, 2006. The debt issuance on October 30, 2006 was an interim financing until the necessary local regulatory approvals were received on December 28, 2006 when the final debt was issued. The debt bears interest at the Brazilian interbank rate plus 2.25% and matures May 20, 2016.

For the year ended 2006, AES recognized a $539 million loss on the sale of Eletropaulo shares and debt restructuring that was comprised of several components, the largest of which resulted from the recognition of previously deferred currency translation losses. In addition, a $22 million loss was included in derivative foreign currency transaction losses. Also recognized on the transaction were an income tax benefit of $175 million, loss on extinguishment of debt of $73 million and minority interest expense of $53 million. The net after-tax loss on the sale and debt restructuring was $512 million.

ACCUMULATED OTHER COMPREHENSIVE LOSS

The following table summarizes the balances comprising accumulated other comprehensive loss, as of December 31, 2006 and 2005.

	December 31, 2006	2005 (Restated)(1)
	(in millions)	
Foreign currency translation adjustment	$ 2,336	$ 3,027
Unrealized derivative losses	126	400
Effect of SFAS No. 158	(94)	
Minimum pension liability	229	229
Securities available for sale	3	
Total	$ 2,600	$ 3,656

(1) See Note 1 related to the restated consolidated financial statements

15. SHARE-BASED COMPENSATION

STOCK OPTIONS AES grants options to purchase shares of common stock under stock option plans. Under the terms of the plans, the Company may issue options to purchase shares of the Company s common stock at a price equal to 100% of the market price at the date the option is granted. Stock options are generally granted based upon a percentage of an employee s base salary. Stock options issued under these plans in 2004, 2005 and 2006 have a three-year vesting schedule and vest in one-third increments over the three-year period. The stock options have a contractual term of 10 years. At December 31, 2006, approximately 11 million shares were remaining for award under the plans. In all circumstances, stock options granted by AES do not entitle the holder the right, or obligate AES, to settle the stock option in cash or other assets of AES.

The weighted average fair value of each option grant has been estimated, as of the grant date, using the Black-Scholes option-pricing model with the following weighted average assumptions:

	December 31, 2006		2005		2004	
Expected volatility	30	%	68	%	68	%
Expected annual dividend yield	0	%	0	%	0	%
Expected option term (years)	6		10		10	
Risk Free interest rate	4.63	%	4.35	%	3.81	%

Prior to January 1, 2006, the Company used the historic volatility of the daily closing price of its stock over the same term as the expected option term, as its expected volatility to determine the fair value using the Black-Scholes option-pricing model. Beginning January 1, 2006, the Company exclusively relies on implied volatility as the expected volatility to determine the fair value using the Black-Scholes option-pricing model. The implied volatility may be exclusively relied upon due to the following factors:

- The Company utilizes a valuation model that is based on a constant volatility assumption to value its employee share options;
- The implied volatility is derived from options to purchase AES stock that are actively traded;
- The market prices of both the traded options and the underlying share are measured at a similar point in time to each other and on a date reasonably close to the grant date of the employee share options;
- The traded options have exercise prices that are both near-the-money and close to the exercise price of the employee share options; and
- The remaining maturities of the traded options on which the estimate is based are at least one year.

Prior to January 1, 2006, the Company used a 10-year expected term to determine the fair value using the Black-Scholes option-pricing model. This term also equals the contractual term of its stock options. Pursuant to SEC Staff Accounting Bulletin (SAB) No. 107, the Company now uses a simplified method to determine the expected term based on the average of the original contractual term and the pro-rata vesting term. Pursuant to SAB No. 107, this simplified method may be used for stock options granted during the years ended December 31, 2006 and 2007, as the Company refines its estimate of the expected term of its stock options. This simplified method may be used as the Company s stock options have the following characteristics:

- The stock options are granted at-the-money;
- Exercisability is conditional only on performing service through the vesting date;
- If an employee terminates service prior to vesting, the employee forfeits the stock options;
- If an employee terminates service after vesting, the employee has a limited time to exercise the stock option; and
- The stock option is not transferable and nonhedgeable.

The Company does not discount the grant date fair values determined to estimate post-vesting restrictions. Post-vesting restrictions include black-out periods when the employee is not able to exercise stock options based on their potential knowledge of information prior to the release of that information to the public.

Using the above assumptions, the weighted average fair value of each stock option granted was $6.82, $13.18, and $6.66, for the years ended December 31, 2006, 2005, and 2004, respectively.

The following table summarizes the components of the Company s stock-based compensation related to its employee stock options recognized in the Company s financial statements:

	December 31, 2006 (in millions)	2005	2004
Pre-tax compensation expense	$ 17	$ 15	$ 17
Tax benefit	$ (5)	$ (4)	$ (4)
Stock Options expense, net of tax	$ 12	$ 11	$ 13
Total intrinsic value of options exercised	$ 78	$ 48	$ 20
Total fair value of options vested	$ 12	$ 15	$ 12
Cash Received from the exercise of stock options	$ 78	$ 27	$ 15
Windfall tax benefits realized from the exercised stock options	$	$ 14	$ 5
Cash used to settle stock options	$	$	$
Total compensation cost capitalized as part of the cost of an asset	$	$	$

As of December 31, 2006, $16 million of total unrecognized compensation cost related to stock options is expected to be recognized over a weighted average period of approximately 1.6 years. There were no modifications to stock option awards during the year ended December 31, 2006.

A summary of the option activity for year ended December 31, 2006 follows (number of options in thousands, $ in millions except per option amounts):

	Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value
Outstanding at December 31, 2005	35,057	$ 15.53		
Exercised	(8,008)	9.70		
Forfeited and expired	(466)	24.39		
Granted	2,428	17.58		
Outstanding at December 31, 2006	29,011	$ 17.19		
Vested and expected to vest at December 31, 2006	28,741	$ 17.20	5.1	$ 234
Eligible for exercise at December 31, 2006	24,956	$ 17.45	4.6	$ 209

The aggregate intrinsic value in the table above represents the total pre-tax intrinsic value (the difference between the Company s closing stock price on the last trading day of the fourth quarter of 2006 and the exercise price, multiplied by the number of in-the-money options) that would have been received by the option holders had all option holders exercised their options on December 31, 2006. The amount of the aggregate intrinsic value will change based on the fair market value of the Company s stock.

The Company initially recognizes compensation cost on the estimated number of instruments for which the requisite service is expected to be rendered. As such, AES has estimated a forfeiture rate of 8.55% and 0% for stock options granted to non-officer employees and officer employees of AES, respectively. Those estimates shall be revised if subsequent information indicates that the actual number of instruments forfeited is likely to differ from previous estimates. Based on the estimated forfeiture rates, the Company expects to expense $16 million on a straight-line basis over a three year period (approximately $5 million per year) related to stock options granted during the year ended December 31, 2006.

The assumptions that the Company has made in determining the grant date fair value of its stock options and the estimated forfeiture rates represent its best estimate. The following table illustrates the effect on the grant date fair value and the annual expected expense for the stock options granted during the year ended December, 2006, using assumptions different from AES s assumptions. The sensitivities are calculated by changing only the noted assumption and keeping all other assumptions used in our calculation constant. As such, the sensitivities may not be additive, so the impact of changing multiple factors simultaneously cannot be calculated by combining the individual sensitivities shown.

	Change in Total Grant date Fair Values (in millions)	**Change in Expected Annual Expense**
Increase of expected volatility to 79%(*)	$ 14	$ 5
Increase of expected option term by 3 years	$ 4	$ 1
Decrease of expected option term by 3 years	$ (5)	$ (2)
Increase of expected forfeiture rates by 50%		