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PART I

The AES Corporation, including all its subsidiaries and affiliates are collectively referred to herein as AES , the Company , us or we .

ITEM 1. BUSINESS

Overview

The AES Corporation is a global power company with operations in 27 countries on five continents. A Delaware corporation formed in 1981, AES is a holding company that, through its subsidiaries, operates in two principal businesses, generation and utilities. The generation business is comprised of our contract generation and competitive supply segments and the utilities business is comprised of our large utilities and growth distribution segments. The Company s generating assets include interests in 120 facilities in 25 countries totaling approximately 44 gigawatts of capacity. AES s electricity distribution networks sell approximately 88,890 gigawatt hours per year.

We believe that the generation and distribution of electricity are essential services required in all industrialized societies. AES is committed to helping meet the world s need for electricity by supplying power from our existing portfolio, as well as by growing our portfolio through the development and construction of new power plants and through selective acquisitions. AES believes that being a large participant in the global power sector gives us the best chance to accomplish our goals. Some of the benefits of being a large organization are the ability to take advantage of scale and to have the resources to develop the best operating and management practices, which will increase overall Company efficiency and productivity. By maintaining a substantial geographic footprint, the Company is positioned to pursue opportunities in those markets with the most favorable characteristics for new investment, namely those having a large and growing need for power. We target specific countries or major geographic regions as areas of primary focus, and seek to build sufficient knowledge and experience in order to increase our ability to successfully compete, and ultimately grow our businesses, in those targeted markets. We believe that this approach also allows us to more efficiently identify and manage the risks inherent in our business.

AES Operates Two Principal Businesses: Generation and Utilities

We build, acquire, own and operate power generation and electricity distribution facilities worldwide. To enhance operational efficiencies across the company, we are organized along two principal lines of business: generation and utilities. The generation business unit encompasses our contract generation and competitive supply segments. These segments generate and sell electricity and related products to utilities or other wholesale or commercial buyers. Performance drivers for these businesses include plant reliability and fuel and fixed cost management. Growth is largely tied to securing new power purchase agreements and expanding capacity. The contract generation and competitive supply segments contributed 37% and 11% of revenues, respectively, for the year 2004.

The utilities business unit encompasses our large utilities and growth distribution segments. These segments sell electricity to residential, business and municipal customers, typically through integrated transmission and distribution systems. Performance drivers for these businesses include providing reliable service, managing working capital, obtaining tariff adjustments and appropriate regulatory treatment for new investments and, in developing countries, reduction of commercial and technical losses. The large utilities and growth distribution segments contributed 38% and 14% of revenues, respectively for the year 2004. The revenues and earnings growth of both our generation and utility businesses vary with changes in electricity demand.

Operating Segments

See Note 21 to the Consolidated Financial Statements included in Item 8 of this Form 10-K/A for additional financial information about our business segments as well as information about our foreign and domestic operations.

Contract Generation

We own and operate plants that sell electricity and related products to utilities or other wholesale customers under long-term contracts. Our contract generation line of business is comprised of generation facilities that have contractually limited their exposure to commodity price risks, primarily electricity price volatility and frequently volume risk, by entering into power sales agreements of five years or longer for 75% or more of their output capacity. The remaining terms of these agreements range from 1 to 26 years. These facilities also generally enter into long-term agreements for most of their fuel supply requirements, or they may enter into tolling or pass through arrangements in which the counter-party directly assumes the risks associated with providing the necessary fuel and then markets the generated power. Through these types of contractual agreements, our contract generation businesses generally produce more predictable cash flows and earnings. The degree of predictability varies from business to business based on the degree to which their exposure is limited by the contracts they have negotiated with their buyers.

Our contract generation segment is comprised of our interests in 70 power generating facilities totaling approximately 24 gigawatts of capacity located in 19 countries. This includes our minority interests in seven power generation facilities totaling over four gigawatts of capacity, and one under construction. Of the more than 22 gigawatts of current operating capacity, 51% is derived from gas-fired facilities, 28% from coal-fired facilities, 13% from hydro facilities, 7% from oil-fired facilities, and less than 1% from biomass facilities.

In most of our contract generating businesses, a single customer contracts for most or all of a particular facility s generated power. To reduce the resulting counter-party credit risk, we seek to contract with creditworthy customers. We also seek to obtain sovereign government guarantees of the customer s obligations. However, we do business in many countries with customers who are not investment grade rated. We believe that locating our plants in different geographic areas helps to mitigate the effects of regional economic downturns, thereby offsetting some of the risks associated with operating in less developed countries. Additionally, in countries in which we own distribution companies, we will seek to contract our generation businesses with the distribution companies that we control.

Certain of our subsidiaries and affiliates (domestic and non-U.S.) are in various stages of developing and constructing new power plants (known as Greenfield power plants or Greenfield). Some have signed long-term contracts or made similar arrangements for the sale of electricity. During 2004, we completed the construction of the second phase of Ras Laffan, in Qatar, a combined cycle facility for an additional 400 MW of installed capacity. We currently have one power generation facility under construction in Spain, totaling approximately 1,200 MW of capacity. As of December 31, 2004, capitalized costs for this project under construction were approximately $392 million. We currently believe that these costs are recoverable but can provide no assurance that we will complete this project and/or that this project will reach commercial operation.

In the contract generation segment, we face most of our competition prior to the execution of a power sales agreement during the development phase of a project. Our competitors in this business include other independent power producers, equipment manufacturers, as well as various utilities and their affiliates. During the operational phase, we traditionally have faced limited competition in this segment 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 will encounter increased competition in attracting new customers and maintaining our current customers as our existing contracts expire.

Competitive Supply

AES owns and operates plants that sell electricity to wholesale customers in competitive markets. These plants typically sell into our power pools under short-term (less than one year) contracts or into daily spot markets. Demand can be affected by weather, electricity transmission constraints, fuel prices and competition. This business segment offers more varied sales, earnings, and cash flow.

In contrast to the contract generation segment discussed above, these facilities generally sell less than 75% of their output under long-term contracts. The prices at which these facilities sell electricity under short-term contracts and in the spot electricity markets are unpredictable and can be volatile. In addition, our operational results in this segment are more sensitive to the impact of market fluctuations in the price of natural gas, coal, oil and other fuels. These businesses also have more significant needs for working capital or credit to support their operations than our businesses in the contract generation segment.

Our competitive supply segment is comprised of 29 power generation facilities totaling over 13 gigawatts of capacity located in 8 countries. Of the total 13 gigawatts of current operating capacity, 60% is derived from coal-fired facilities, 7% from gas-fired facilities, 29% from hydro facilities, 2% from oil facilities, 1% from petroleum coke facilities and less than 1% from biomass facilities. In 2004, we completed the refurbishment of the Bayano facility in Panama, which added an additional 12 MW of capacity.

The absence of long-term contracts makes future production volumes uncertain, which in turn makes it difficult to forecast the amount of fuel needed to support those volumes. As a result, competitive supply businesses are exposed to volume risk in connection with their purchases of natural gas, coal and other raw materials. Where appropriate, we have hedged a portion of our financial performance against the effects of fluctuations in energy commodity prices using such strategies as commodity forward contracts, futures, swaps and options.

Although we maintain credit policies with regard to our counterparties, there can be no assurance that ultimately they will be able to fulfill their contractual obligations. Volatility in electricity markets in the United States causes increases in credit risk, a decline in the number and quality of market participants with strong credit ratings, and considerably less liquidity in energy markets.

We compete in this segment with numerous other independent power producers, energy marketers and traders, energy merchants, transmission and distribution providers, and retail energy suppliers. Competitive factors in this segment include reliability, operational cost and third party credit requirements.

Large Utilities

Our large utility segment consists of electric utilities that are of significant size and maintain a monopoly franchise within a defined service area. In most cases our large utilities combine generation, transmission and distribution capabilities. We own and operate three large electric utilities: Indianapolis Power & Light Company (IPL) in the U.S.; Eletropaulo Metropolitana Electricidade de São Paulo SA (Eletropaulo) in Brazil; and CA La Electricidad de Caracas (EDC) in Venezuela. These utilities sell electricity under regulated tariff agreements and each have transmission and distribution capabilities; IPL and EDC also have generation plants. We have a 100% common equity interest in IPL through our ownership of IPALCO Enterprises, Inc. (IPALCO), a 32% economic ownership interest in Eletropaulo after the January 2004 restructuring and an 86% common equity interest in EDC. Our large utilities aggregate approximately 6 gigawatts of generation capacity and serve over 6.5 million customers, with annual sales of 59,505 gigawatt hours. Our large utilities are subject to extensive regulation at multiple governmental levels relating to ownership, marketing, delivery and pricing of electricity and gas, with a focus on protecting customers. Large utility revenues result primarily from retail electricity sales to customers under regulated tariff or concession agreements and, to a lesser extent, from contractual agreements of varying lengths and provisions.

IPALCO is a holding company and its principal subsidiary is Indianapolis Power & Light Company (IPL). IPL is engaged in generating, transmitting, distributing and selling electric energy to approximately 460,000 customers in the city of Indianapolis and neighboring areas within the state of Indiana. IPL 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 net generation winter capability is 3,370 MW and net summer capability is 3,252 MW. We acquired IPALCO in March 2001.

Eletropaulo has served the São Paulo, Brazil area for over 100 years and, with over five million customers, is the largest electricity distribution company in the Americas in terms of customers. Eletropaulo s concession contract with the Brazilian National Electric Energy Agency (ANEEL), the government agency responsible for regulating the Brazilian electric industry, entitles Eletropaulo to distribute electricity in its service area for 30 years from the date of our acquisition. 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, covering 5 million customers or 44% of the population in the State of São Paulo, Brazil.

EDC was founded in 1895 and is the largest private-sector electric utility in Venezuela serving approximately one million customers. EDC generates, transmits and distributes electricity to customers in metropolitan Caracas and its surrounding area. EDC s distribution area covers 5,176 square kilometers. EDC has an installed generating capacity of 2,616 MW.

Historically, energy utilities have operated within specific service territories where they were essentially the sole suppliers of electricity services. As a result, competition was limited to alternative means of energy such as gas and fuel. However, in certain locations, the large utilities business faces 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 our large utilities future operations, cash flows and financial condition.

Growth Distribution

Our growth distribution segment is comprised of smaller distribution facilities in developing countries where electricity demand is expected to grow faster than in more developed markets. These facilities serve smaller service areas and generally need substantial infrastructure investments. Electricity sales are made under regulated tariff agreements or under existing regulatory laws and provisions. The conditions of the business environment in a developing nation also provide for significant opportunities to implement operating improvements that may stimulate growth in earnings and cash flow performance. These growth rates may be greater than those typically achievable in our other business segments. Many of these businesses face challenges unique to developing countries including outdated equipment, significant electricity theft-related losses, cultural problems associated with customer safety and non-payment, emerging economies, and potentially less stable governments or regulatory regimes. Distribution facilities included in this segment may include generation, transmission, distribution or related services companies. The results of operations of our growth distribution business are sensitive to changes in economic growth and regulation, abnormal weather conditions affecting each local market, as well as the success of the operational changes that have been implemented.

We derive growth distribution revenues from the distribution and sale of electricity pursuant to the provisions of long-term electricity sale concessions granted by the appropriate governmental authorities, or in some locations, under existing regulatory laws and provisions. One of our distribution facilities, located in Cameroon, SONEL, is integrated, in that it also owns transmission lines and electric generation facilities. The facilities currently in this segment have approximately 935 gross MW of generation and serve more than 4.7 million customers with sales of 26,886 gigawatt hours in Argentina, Brazil, Cameroon, Dominican Republic, El Salvador and Ukraine.

The businesses in the growth distribution segment 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 growth distribution related businesses for periods longer than we have, and have accumulated more significant portfolios. Relevant competitive factors include financial resources, governmental assistance, and access to non-recourse financing and regulatory restrictions.

Facilities

The following tables present information with respect to the facilities in each of our four business segments. The amounts under Gross MW and Approximate Gigawatt Hours represent the gross amounts for each facility without regard to our percentage of ownership interest in the facility.

Contract Generation
(As of December 31, 2004)

Generation Facilities	Dominant Fuel	Year of Acquisition or Commencement of Commercial Operations	Geographic Location	Gross MW	AES Equity Interest (Percent, Rounded)
North America					
Beaver Valley	Coal	1987	USA	125	100
Central Valley Delano	Biomass	2001	USA	50	100
Central Valley Mendota	Biomass	2001	USA	25	100
Hawaii	Coal	1992	USA	203	100
Hemphill	Biomass	2001	USA	14	67
Ironwood	Gas	2001	USA	705	100
Kingston	Gas	1997	Canada	110	50
Placerita	Gas	1989	USA	120	100
Red Oak	Gas	2002	USA	832	100
Shady Point	Coal	1991	USA	320	100
Southland Alamitos	Gas	1998	USA	1,986	100
Southland Huntington Beach	Gas	1998	USA	904	100
Southland Redondo Beach	Gas	1998	USA	1,334	100
Thames	Coal	1990	USA	181	100
Warrior Run	Coal	2000	USA	180	100
Caribbean					
Andres	Gas	2003	Dominican Republic	304	100
Itabo (5 plants)(1)	Coal/Oil	2000	Dominican Republic	586	25
Los Mina	Gas	1997	Dominican Republic	210	100
Mérida III	Gas	2000	Mexico	495	55
Puerto Rico	Coal	2002	USA	454	100
South America					
Gener Centrogener (7 plants)(2)	Hydro/ Coal/Oil	2000	Chile	682	99
Gener Electrica de Santiago (2 plants)(3)	Gas/Oil	2000	Chile	479	89
Gener Energia Verde (3 plants)(4)	Biomass/ Diesel	2000	Chile	42	99
Gener Guacolda	Coal	2000	Chile	304	49
Gener Norgener	Coal	2000	Chile	277	99
Gener TermoAndes	Gas	2000	Argentina	643	99
Tietê (10 plants)(5)(6)	Hydro	1999	Brazil	2,650	24
Uruguaiana(6)	Gas	2000	Brazil	639	46
Europe/Africa					
Bohemia	Coal	2001	Czech Republic	140	100
Borsod	Biomass	1996	Hungary	96	100
Ebute	Gas	2001	Nigeria	306	95

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Elsta	Gas	1998	Netherlands	630	50
Kilroot	Coal/Oil	1992	UK	520	97
Tisza II	Oil/Gas	1996	Hungary	860	100
Asia					
Aixi	Coal	1998	China	51	71
Barka	Gas	2003	Oman	427	35
Chengdu	Gas	1997	China	48	35
Cili	Hydro	1994	China	26	51
Hefei	Oil	1997	China	115	70
Jiaozuo	Coal	1997	China	250	70
Kelanitissa	Diesel	2003	Sri Lanka	168	90
Lal Pir	Oil	1997	Pakistan	365	55
OPGC	Coal	1998	India	420	49
Pak Gen	Oil	1998	Pakistan	365	55
Ras Laffan	Gas	2004	Qatar	756	55
Wuhu	Coal	1996	China	250	25
Yangcheng	Coal	2001	China	2,100	25
			Total	22,747	

Under Construction

Generation Facilities	**Dominant Fuel**	**Commencement of Commercial Operations**	**Geographic Location**	**Gross MW**	**AES Equity Interest (Percent)**
Europe/Africa					
Cartagena	Gas	2006	Spain	1,200	71

(1) Itabo plants: Itabo, Santo Domingo, Timbeque, Los Mina, Higuamo

(2) Gener-Centrogener plants: Ventanas, Laguna Verde, Laguna Verde Turbogas, Alfalfal, Maitenes, Queltehues, Volcán

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

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

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

(6) As a result of the restructuring described above between some of our Brazilian holding companies and BNDES which was completed in January 2004, we have a 46% ownership interest in AES Uruguaiana and a 24% interest in AES Tietê. AES retains control of these entities through the holding company, Brasiliana Energia, S.A.

Competitive Supply
(As of December 31, 2004)

Generation Facilities	Dominant Fuel	Year of Acquisition or Commencement of Commercial Operations	Geographic Location	Gross MW	AES Equity Interest (Percent, Rounded)
North America					
Cayuga	Coal	1999	USA	306	100
Deepwater	Pet Coke	1986	USA	160	100
Greenidge	Coal	1999	USA	161	100
Somerset	Coal	1999	USA	675	100
Westover	Coal	1999	USA	126	100
Caribbean					
Bayano	Hydro	1999	Panama	260	49
Chiriqui Esti	Hydro	2003	Panama	120	49
Chiriqui La Estrella	Hydro	1999	Panama	42	49
Chiriqui Los Valles	Hydro	1999	Panama	48	49
Chivor	Hydro	2000	Colombia	1,000	99
Panama	Oil	1999	Panama	43	49
South America					
Alicura	Hydro	2000	Argentina	1,040	96
Central Dique	Gas	1998	Argentina	68	51
Paraná-GT	Gas	2001	Argentina	845	100
Quebrada de Ullum(1)	Hydro	2004	Argentina	45	0
Rio Juramento Cabra Corral	Hydro	1995	Argentina	102	98
Rio Juramento El Tunal	Hydro	1995	Argentina	10	98
San Juan Sarmiento	Gas	1996	Argentina	33	98
San Juan Ullum	Hydro	1996	Argentina	45	98
San Nicolás	Coal	1993	Argentina	650	96
Europe/Africa					
Indian Queens	Oil	1996	UK	140	100
Ottana	Oil	2001	Italy	140	100
Tiszapalkonya	Biomass/Coal	1996	Hungary	125	100
Asia					
Ekibastuz	Coal	1996	Kazakhstan	4,000	100
Shulbinsk	Hydro	1997	Kazakhstan	702	100 Concession
Sogrinsk CHP	Coal	1997	Kazakhstan	301	100
Ust-Kamenogorsk	Hydro	1997	Kazakhstan	331	100 Concession
Ust-Kamenogorsk CHP	Coal	1997	Kazakhstan	1,356	100
Ust-Kamenogorsk Heat Nets(1)	Coal	1998	Kazakhstan	260	0
			Total	13,134	

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Distribution Facilities	Year of Acquisition or Commencement of Commercial Operations	Geographic Location	Approximate Number of Customers Served	Approximate Gigawatt Hours	AES Equity Interest (Percent, Rounded)
Asia					
Eastern Kazakhstan REC(1)	1999	Kazakhstan	280,000	1,411	0
Semipalatinsk REC(1)	1999	Kazakhstan	180,000	1,088	0
			Total	2,499	

(1) Although our equity interest in these businesses is zero, we operate these businesses through a management agreement. We previously owned Quebrada de Ullum from 1998 to 2004.

Large Utilities
(As of December 31, 2004)

Generation Facilities	Dominant Fuel	Year of Acquisition or Commencement of Commercial Operations	Geographic Location	Gross MW	AES Equity Interest (Percent, Rounded)
North America					
IPL (4 plants)(1)	Coal/Gas/Oil	2001	USA	3,252	100
Caribbean					
EDC (5 plants)(2)	Oil/Gas	2000	Venezuela	2,616	86
			Total	5,868	

Distribution Facilities	Year of Acquisition	Geographic Location	Approximate Number of Customers Served	Approximate Gigawatt Hours	AES Equity Interest (Percent, Rounded)
North America					
IPL	2001	USA	460,000	16,205	100
Caribbean					
EDC	2000	Venezuela	1,000,000	10,500	86
South America					
Eletropaulo(3)	1998	Brazil	5,050,000	32,800	32
			Total	59,505	

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

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

(3) As a result of the restructuring described above between some of our Brazilian holding companies and BNDES which was completed in January 2004, our ownership interest in Eletropaulo is 32%. AES retains control through the holding company, Brasiliana Energia, S.A.

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Growth Distribution
(As of December 31, 2004)

Generation Facilities	Dominant Fuel	Year of Acquisition or Commencement of Commercial Operations	Geographic Location	Gross MW	AES Equity Interest (Percent, Rounded)
Europe/Africa					
SONEL (12 plants)(1)	Hydro/Diesel/Heavy Fuel Oil	2001	Cameroon	935	56
			Total	935	

Distribution Facilities	Year of Acquisition or Commencement of Commercial Operations	Geographic Location	Approximate Number of Customers Served	Approximate Gigawatt Hours	AES Equity Interest (Percent, Rounded)
Caribbean					
CAESS	2000	El Salvador	477,700	1,765	75
CLESA	1998	El Salvador	261,000	685	64
DEUSEM	2000	El Salvador	52,000	92	74
EDE Este(2)	2004	Dominican Republic	293,000	1,900	0
EEO	2000	El Salvador	194,000	392	89
South America					
Edelap	1998	Argentina	289,150	2,200	90
Eden	1997	Argentina	291,200	1,960	90
Edes	1997	Argentina	151,200	670	90
Sul(3)	1997	Brazil	1,021,900	8,022	100
Europe/Africa					
Kievoblenergo	2001	Ukraine	811,000	3,800	90
Rivneenergo	2001	Ukraine	403,000	1,700	79
SONEL	2001	Cameroon	505,300	3,700	56
			Total	26,886	

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(1) SONEL plants: Edéa, Song Loulou, Limbé, Bassa, Bafoussam, Logbaba, Logbaba II, Oyomabang I, Oyomabang II, Mefou, Lagdo, Djamboutou

(2) Although our equity interest in this business is zero, we operate it through a management agreement. AES previously had a controlling interest in EDE Este from 1999 to 2004.

(3) As a result of the restructuring described above between some of our Brazilian holding companies and BNDES which was completed in January 2004, AES Sul may be contributed at the option of BNDES to Brasiliana Energia after AES Sul has completed its own debt restructuring.

Growth Opportunities

AES continuously considers options for growth opportunities to expand our business. In addition to expanding our two primary lines of business, power generation and distribution, we believe we can leverage the skills and experience necessary to be successful in our primary businesses into other businesses that have similar characteristics. We believe the transferable skills include our knowledge and skill in dealing with complex deal structuring and project financing for large capital intensive projects and dynamic local

political and regulatory environments. We believe we have an additional advantage in situations where we can find a direct link to our existing businesses. Our existing presence in certain countries can provide the relationships and insight into local rules, regulations, politics, and business practices needed to be successful in both power and related non-power sectors. For example, we have already begun to implement this strategy in Kazakhstan where we own and operate coal mines, the Middle East, where we own and operate water desalination plants, and the Dominican Republic, where we own and operate an LNG regasification terminal, each ancillary to our existing power businesses.

Customers

We sell to a wide variety of customers. No individual customer accounted for more than 10% of our 2004 total revenues.

Employees

As of December 31, 2004, we employed approximately 30,000 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 web 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 at *http://www.aes.com*. After the reports are filed with the Securities and Exchange Commission, they are available from the Company free of charge. Material contained on our website is not part of and is not incorporated by reference in this report on Form 10-K/A.

Executive Officers of the Registrant

The following individuals listed below are AES s present executive officers:

Paul T. Hanrahan, 47 years old, is the President and Chief Executive Officer of the Company. Prior to assuming his current position, Mr. Hanrahan was the Chief Operating Officer and Executive Vice President of the Company. 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.

Joseph C. Brandt, 40 years old, is Executive Vice President, Chief Operating Officer of Integrated Utilities of the Company. From January 2002 to February 2003, Mr. Brandt was President and Group Manager for AES Andes, covering AES business interests in Argentina. From 1998 to 2002, Mr. Brandt held various corporate and development positions with the Company. Prior to joining the Company, Mr. Brandt was an Investment Analyst & Portfolio Manager at McGinnis Advisors in San Antonio, Texas. Mr. Brandt also held positions at the law firm, Latham & Watkins, and at the University of Santa Clara, California. The Company announced on March 30, 2005 that Mr. Brandt is leaving the Company.

Robert F. Hemphill, Jr., 61 years old, was appointed Executive Vice President, Global Development on February 5, 2004. Mr. Hemphill served as a director of AES 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 the Company in 1982. Mr. Hemphill also serves on the Boards of Reactive Nanotechnologies, Inc., Trophogen Inc. and Chameleon Technologies.

William R. Luraschi, 41 years old, was appointed Executive Vice President in July 2003 and has been Vice President of the Company since January 1998, and General Counsel of the Company since January 1994. Mr. Luraschi also was Secretary from February 1996 until June 2002. Prior to that, Mr. Luraschi was an attorney with the law firm of Chadbourne & Parke L.L.P.

John Ruggirello, 54 years old, was appointed Chief Operating Officer for Generation in February 2003. Mr. Ruggirello was appointed Executive Vice President of the Company in February 2000, was Senior Vice President until February 2000 and was appointed Vice President in January 1997. Mr. Ruggirello previously led the AES Enterprise Group, with responsibility for project development, construction and plant operations in the United States. Prior to joining the Company in 1987, Mr. Ruggirello was Operations Manager for a division of the Diamond Shamrock Corporation.

Barry J. Sharp, 45 years old, was appointed Chief Financial Officer in 1987. Mr. Sharp was appointed Executive Vice President in February 2001, Senior Vice President in January 1998 and had been a Vice President since 1987. He also served as Secretary of the Company until February 1996. From 1986 to 1987, Mr. Sharp served as the Company s Director of Finance and Administration. Mr. Sharp is a certified public accountant.

Regulatory Matters

United States. The Federal Energy Regulatory Commission (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 of 1938. The Securities and Exchange Commission (SEC) has regulatory powers with respect to owners of electric and natural gas utilities under the Public Utility Holding Company Act of 1935 (PUHCA). Holding companies that are registered with the SEC under PUHCA are subject to extensive regulation with respect to corporate structure and financial transactions. The enactment of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the FERC s adoption of regulations under it provided incentives for the development of cogeneration facilities and small power production facilities utilizing alternative or renewable fuels by establishing certain exemptions from the FPA and PUHCA for the owners of qualifying facilities. The passage of Section 32 of PUHCA in 1992 further encouraged independent power production by providing exemptions from PUHCA for exempt wholesale generators. Exempt wholesale generators are entities determined by the FERC to be exclusively engaged, directly or indirectly in the business of owning and/or operating specified eligible facilities and selling electric energy exclusively at wholesale or, if located in a foreign country, at wholesale or retail. Section 33 of PUHCA, also passed in 1992, encouraged investment in foreign utilities by exempting such investments from regulation under PUHCA.

Over the past decade, a series of regulatory policies have been partially implemented in the United States that encourage competition in wholesale and retail electricity markets. These policies have been implemented at the federal level and in many states, reflecting the federal structure of the U.S. system. 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. 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 jurisdiction was required to file an Open Access Transmission Tariff. In 2000, the FERC issued Order 2000, that 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. The RTO would assume functions traditionally handled by utilities, such as security coordination and planning.

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 a 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 re-examination has not occurred in a uniform manner, but rather has differed from state to state and has differed 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, while the FERC has continued its efforts to enhance open access electric transmission and enhance competition in bulk power 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. We believe 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 has shifted toward non-utility entities, referred to as Independent Power Producers (IPPs) or Electric Wholesale Generators (EWGs), 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 rates. The FERC is in the process of issuing a rulemaking concerning the four criteria examined in granting market based rate authority and the resulting regulations may result in a more stringent analysis and therefore the denial of market based rate authority to a number of entities. Recently there has also been a shift back to utilities supplying their own generation, through affiliate contracts, acquisition of distressed assets, and traditional utility construction. These assets are included in ratebase and represent a move back to traditional cost of service ratemaking regulation.

The FERC proposed new regulations several years ago to implement a standard market design (SMD) for wholesale electric markets. This proposed rule generally is intended by the FERC to further promote non-discriminatory, open access wholesale transmission and workably competitive wholesale generation markets. Some states and members of Congress have expressed concerns regarding the affect of the SMD proposal on their jurisdiction over retail related services and price levels within their jurisdictions and have included language in proposed energy legislation restricting the FERC s authority and prohibiting the implementation of SMD. Given the strong opposition from state legislators, governors and regulators, the FERC has abandoned attempts at implementing the SMD proposals as written and has begun using individual case law to establish precedents supporting components of SMD.

The U.S. Congress over the past few years has considered various legislative proposals to restructure the electric industry that, among other things, would repeal PUHCA, provide for mandatory reliability standards and provide for prospective, partial repeal of PURPA. In addition, proposals have been introduced in Congress that incorporate provisions related to restructuring electricity markets. Different versions of such legislation passed both houses of Congress late in the last session and included provisions related to PUHCA repeal. Such legislation would have provided the FERC with new authority related to imposing reliability standards, but would have delayed the FERC implementation of the SMD rule for several years. A joint Conference Committee produced a report that was acceptable to the House, but that was unable to obtain sufficient votes in the Senate to limit extended debate by opponents seeking to delay, or filibuster final adoption of the bill. As a result, the 108th Congress adjourned and was unable to pass comprehensive energy regulatory legislation. No energy regulatory legislation has been put to a vote in the 109th Congress at this time. Both the House and Senate are set to debate versions of the Energy Bill that are similar to what was presented during the last session. At this point, it is uncertain whether any of this legislation will be enacted and if so, what its effect will be on our business. There is a high probability that legislation addressing reliability will be passed either as part of the comprehensive Energy Bill or as stand alone legislation. Reliability legislation would provide the FERC with authority to certify an Electric

Reliability Organization (ERO) that will set mandatory standards. The North American Electric Reliability Council (NERC) will most likely fill this role and will have enforcement authority. NERC recently adopted a set of formalized reliability standards, that consist of existing operating and planning standards. Although NERC does not currently have authority to mandate compliance with these standards utilities generally choose to voluntarily comply with the standards. Legislation would give NERC the ability to make standards mandatory and would grant them the authority to enforce these standards through the issuance of financial penalties.

There are currently major changes pending in the structure and rules governing the California wholesale energy market. The outcome of any significant market or regulatory changes will affect market conditions for all market participants, including AES. As a result of price volatility during 2000 and 2001, a number of parties, including the State of California and the California Independent System Operator, are seeking refunds from certain entities that supplied power within the state during 2000 and 2001, although our overall exposure to this risk is largely mitigated as a result of our tolling agreement related to the Southland plants. However, a recent Ninth Circuit Court of Appeals Opinion found that the FERC had abused its administrative discretion by declining to order refunds for violations of its reporting requirements and remanded the issue to the FERC. AES Placerita made sales to the California Independent System Operator during this period. Depending on the method of calculating refunds and the time period to which this method is applied, AES Placerita s exposure could be $23 million. There are no performance bonds or corporate guarantees supporting AES Placerita and no liability from the refund proceedings for other AES entities. In addition, we have been named in a number of lawsuits covering this period and are not certain of their outcome. See Item 3 Legal Proceedings.

We are an exempt public utility holding company under Section 3(a)(5) of PUHCA, which exempts us from most regulation under PUHCA, and also allows us to own 100 percent interests in qualifying facilities under PURPA. IPALCO is an exempt public utility holding company under Section 3(a)(1) of PUHCA, which exempts it from most regulation under PUHCA.

Argentina. In January and February 2002, the Argentine government adopted many new economic measures as a result of the continuing political, social and economic crisis. These economic measures included the abandonment of the country s fixed dollar-to-peso exchange rate, the conversion of U.S. dollar-denominated loans into pesos and the placement of restrictions on the convertibility of the Argentine peso. In 2003 and 2004, the political and social situation in Argentina showed signs of stabilization, the Argentine peso appreciated against the U.S. dollar, and the economy and electricity demand started to recover. Presidential elections and the establishment of a new government occurred in May 2003.

The regulations adopted in 2002 and 2003 in the energy sector effectively overturned the U.S. dollar based nature of the electricity sector. Formerly, both the wholesale generation market and the distribution sector received payments that were linked to the U.S. dollar, not only because of the Convertibility Law that pegged the peso at a 1:1 exchange rate with the U.S. dollar, but also because the price paid for wholesale generation reflected the U.S. dollar-linked nature of the fuels used by the country s generating facilities. All prices to consumers are now fixed in pesos.

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 (pesofied), following the pesofication of the price of natural gas. However, the authorities permitted the production 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 will be set considering only production costs declared with natural gas. Therefore, while generators received remuneration for the use of alternative fuel, this cost is not considered when setting at the spot price.

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Because of this, generation prices still reflect an artificially low fuel price and, as a result, the real price received for wholesale generation has been reduced by nearly 50% from 2001. In addition, during 2003 new regulations have fixed a cap to the wholesale power market prices and have changed the collections conditions for the energy and capacity sales to the wholesale power market.

During 2004, the Energy Secretariat reached agreements with natural gas and electricity producers, to reform the energy markets. The agreement with natural gas producers establishes a recovery path that increases wellhead prices to 80% of the U.S. dollar price. 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), which will fund new capacity to be installed by 2007. In exchange, the Government committed to reform the market rules to match the pre-crisis rules, setting the capacity payment with a U.S. dollar reference and eliminating all regulations fixing an artificially low price in the wholesale market. The Government of Argentina reached an agreement on this with 70% of the generators by December 2004. There can be no assurance, however, that the Government of Argentina 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 have been converted to pesos and are frozen at the peso notional rate as of December 31, 2001. In October 2003, the Argentine Congress enacted Law No. 25,790 that established the procedure for renegotiations of the public utilities concessions and extended the period for that process until December 31, 2004. Law No. 25,972 dated December 17, 2004, extended the term once again until December 31, 2005. In combination, these circumstances create significant uncertainty surrounding the performance of the electricity industry in Argentina, including the Argentine subsidiaries of AES.

EDEN and EDES, two AES distribution facilities in Argentina, are in the process of re-negotiating their concession contracts regulated by the Ministry of Infrastructure and Public Services of the Province of Buenos Aires. In September, 2004 the Ministry of Infrastructure of the Province of Buenos Aires issued a resolution asking for an economic costs model representative of the operation and maintenance costs of an efficient company, and the valuation of the assets dedicated to the service. EDEN-EDES presented to the Ministry of Infrastructure of the Province of Buenos Aires the economic costs model and an assets valuation, audited by Technologic Institute of Buenos Aires.

On November 12, 2004, EDELAP, an AES distribution facility, signed a Letter of Understanding with the Government in order to renegotiate its concession contract and to start a tariff reform process for completion by June 2005. As a first step during this process, and subject to Congressional approval and ratification by the Executive Branch, a Distribution Value Added (DVA) increase of over 20% since February 1, 2005 has been granted. This Letter of Understanding is the first of its kind signed with UNIREN (Unit for the Renegotiation and Analysis of Public Services Contracts) in the Argentine electricity sector. AES will postpone any action until the tariff reset is finalized (not later than December 2005). The Letter of Understanding provides that in case the government does not fulfill its commitments, AES may re-start the international claim process.

Brazil. Under the present regulatory structure, the power industry in Brazil is regulated by the Federal 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

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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.

Rationing Agreement. The electricity industry in Brazil reached a critical point in 2001, as the result of a series of regulatory, meteorological and market-driven problems. The Brazilian Wholesale Energy Market, or MAE, had a poor performance record due to an inability to resolve commercial disputes. In addition, the combined effects of growth in demand, decreased rainfall on the country s heavily hydro-electric dependent generating capacity and delays by the Brazilian energy regulatory authorities in developing an attractive regulatory structure (necessary to encourage new generation in the country) led to shortages of electricity compared to demand in certain regions of Brazil. As a result in June 2001, the Brazilian government implemented a program for the rationing of electricity consumption.

Pursuant to the rationing program, consumers in the Northeast, Southeast and Midwest regions of Brazil were required to reduce their consumption by varied percentages, depending on the type of customer. The objective of the rationing program was to reduce aggregate consumption by 20% in those regions in which it was in force (including the AES Eletropaulo s service area). As a result of the mandatory consumption reduction in AES Eletropaulo s service area, the company experienced a 13% decrease in energy distributed in 2001, as compared to 2000. After the 2001-2002 rain season produced rainfall sufficient to replenish reservoir levels to an adequate level (as determined by the Federal Government), the rationing program was terminated in at the end of February 2002.

On December 21, 2001, in order to compensate electricity distributors and generators for losses incurred during the rationing program, the President of Brazil issued a provisional measure. The provisional measure provided general authorization for: (i) the pass-through to consumers of costs incurred by generators for the purchase of energy at spot prices during the rationing program, (ii) the recovery in future years of revenue losses sustained by distributors during the rationing period, through an Extraordinary Tariff Adjustment (RTE), (iii) the institution, by the Brazilian National Bank for Economic and Social Development (BNDES), of an emergency support program in order to compensate distributors, generators and independent power producers for the rationing impacts, which contemplates the disbursement of some loans to these companies.

In addition, the Federal Government provided a solution to a long-standing regulatory issue related to Parcel A costs (non-manageable costs relating to energy purchase and sector charges that each distribution company is permitted to pass through to customers). In the past, the Brazilian regulator had granted tariff increases that proved to be insufficient to fully recover Parcel A costs incurred by distribution companies. A tracking account mechanism (CVA) was established in order to mitigate risks relating to Parcel A costs not being passed-through to tariffs, and, as part of the agreement, distribution companies would be allowed to recover Parcel A costs related to the period between January 1, 2001 and October 25, 2001. Parcel A costs incurred prior to January 1, 2001 were not allowed to be recovered under the Rationing Agreement and, as a result, the Company wrote-off approximately $160 million of Parcel A costs incurred prior to 2001.

Generators and distributors losses are recovered by the RTE, as calculated pursuant to Resolution #31 issued by ANEEL on January 24, 2002 and Resolution #91 issued by the Crisis Committee on December 21, 2001. As of January 2002, the Company was permitted to charge consumers the RTE over a 65-month period. However, as the market did not perform as expected after the rationing and the interest rate applied in order to adjust such regulatory asset (Selic the Brazilian interbank interest rate) was higher than predicted, there was a need to review the figures previously determined by ANEEL. The Regulator reviewed the time over which RTE would be in place in order to allow the full recovery of the Rationing Agreement values and ANEEL s Normative Resolution # 001, issued on January 12, 2004, established the extension of AES Eletropaulo s RTE recovery period (from the 65 to 70 months), and that Parcel A recovery will happen only after the RTE recovery, and along the period that is deemed necessary.

Under the Rationing Agreement, AES Sul was permitted to record additional revenue and a corresponding receivable from the spot market during 2001 and the first quarter of 2002. However, ANEEL promulgated Order 288 in May 2002, which retroactively changed certain previously communicated methodologies, and resulted in a change in the calculation methods for electricity pricing in the MAE. We recorded a pretax provision of approximately $160 million, including the amounts for AES Sul against revenues during May 2002, to reflect the negative impacts of this retroactive regulatory decision.

AES Sul filed a motion for an administrative appeal with ANEEL challenging the legality of Order 288 and requested a preliminary injunction in the Brazilian federal courts to suspend the effect of Order 288 pending the determination of the administrative appeal. Both appeals were denied. In August 2002, AES Sul appealed and in October 2002, the court confirmed the preliminary injunction s validity. Its effect, however, was subsequently suspended pending an appeal by ANEEL and an appeal by AES Sul.

In December 2002, prior to any settlement of the MAE, AES Sul filed an incidental claim requesting, by way of a preliminary injunction, the suspension of our debts registered in the MAE. A Brazilian federal judge granted the injunction and ordered that an amount equal to one-half of the amount claimed by AES Sul from inter-market trading of energy purchased from Itaipu in 2001 be set aside by the MAE in an escrow account. The injunction was subsequently overturned. Sul has appealed that decision and requested the judge to reinstate the injunction and the escrow account.

The MAE partially settled its registered transactions between late December 2002 and early 2003. If a settlement occurs with the effect of Order 288 in place, AES Sul will owe approximately a net amount of $30 million, based upon the December 31, 2004 exchange rate. AES Sul does not believe it will have sufficient funds to make this payment and several creditors have filed lawsuits in an effort to collect amounts they claim are overdue. AES Sul is petitioning the courts to aggregate the individual lawsuits with payments until the matter is resolved. If AES Sul prevails and the MAE settlement occurs absent the effect of Order 288, AES Sul will receive approximately $132 million, based upon the December 31, 2004 exchange rate. If AES Sul is unsuccessful and unable to pay any amount that may be due to MAE, penalties and fines could be imposed up to and including the termination of the concession contract by ANEEL. AES Sul is current on all MAE charges and costs incurred subsequent to the period in question in the order 288 matter. All amounts, including the debt in case the company loses the case, are provisioned in AES Sul s books.

We do not believe that the terms of the industry-wide Rationing Agreement, as currently being implemented, restored the economic equilibrium of all of the concession contracts because the agreement covered only the Rationing Period. The consumption never returned to the previous levels and previously communicated methodologies for implementing the terms of the Rationing Agreement were retroactively changed.

Parcel A tracking account (CVA). The CVA is a tracking account that records non-manageable costs monthly price variations (positive and negative) over the course of the year. At each tariff adjustment date, distribution companies would be allowed an additional tariff increase, for the following 12 months, in order to compensate for the accumulated value of the CVA plus interest. Prior to the implementation of the tracking account mechanism (effective as of January, 2001), distribution companies were facing massive losses relating to these costs variations. In accordance with the regulation, the costs currently allowed to be recorded in the tracking account relate to energy purchase and some system charges.

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On April 4, 2003, the Ministry of Mines and Energy (MME) issued a decree postponing, for a 1-year period, the tracking account tariff increase. According to this decree, the pass-through to tariffs of the amounts accumulated in the tracking account for the distribution concessionaires that had been scheduled to occur from April 8, 2003 to April 7, 2004 were postponed to the subsequent year s tariff adjustment. As a result, in the case of AES Sul and Eletropaulo, the pass-through of the tracking account balance for 2003, that should originally have happened on April 19, 2003 and July 4, 2003 amounted to approximately $12 million and $173 million, respectively. These amounts accumulated over the ensuing twelve months and are to be recovered over a 24-month period rather than the usual 12-month period. Eletropaulo and AES Sul received in their respective 2004 tariff adjustments, 50% of the deferred CVA recoverable over a 12-month period. Management expects to receive the additional 50% as part of the 2005 tariff adjustments, which will be recoverable over the ensuing 12-month period.

In order to compensate for the deferral of the increase relating to the tracking account, BNDES provided distribution companies with loans, which will be repaid during the recovery period. On December 23, 2004, AES Sul received a BNDES loan equivalent to $16.5 million and on June 3, 2004, Eletropaulo received a BNDES loan equivalent to $166 million, both to be repaid within the recovery period.

Rate Making. 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
- Extraordinary Revisions, in the event of significant changes in concessionaires cost structure

Annual Tariff Adjustment (IRT). The primary purpose of the 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 the inflation. An X-Factor is applied to capture the sharing of efficiency gains, effectively reducing the inflation index that is applied to Parcel B costs.

ANEEL authorized an average adjustment of 18.62% for Eletropaulo tariffs on July 4, 2004. However, because of a default by Companhia Energética de São Paulo (CESP), one of the generation companies that sells electric energy to Eletropaulo, a rate of 17.91% was applied until the default was cured on September 21, 2004. ANEEL authorized an average adjustment of 13.27% for AES Sul on April 19, 2004.

Tariff Reset. In 2003, Brazil entered a major round of tariff revisions. On April 19, 2003, AES Sul was granted a rate increase by ANEEL of 16.14%. On July 4, 2003, ANEEL granted a tariff revision for AES Eletropaulo of 10.95% plus 0.4% to be included in the tariff adjustment for the ensuing 12-month period, resulting in an 11.35% revision. These tariff revisions were meant to re-establish a tariff level that would cover (i) costs for the energy purchased and other non-manageable costs, (ii) operations/maintenance costs of a Reference Company, and (iii) capital remuneration on the Company s asset base using a replacement cost methodology. Each of these items is evaluated based on a Test-Year, as defined by ANEEL, which encompasses the following 12 months after the tariff increase.

There remain a number of critical issues that were either not adequately considered in the tariff reset process or remain unresolved. The operations and maintenance costs considered in the tariff are based on the concept of a Reference Company, not the actual costs of the Company. In many cases, the Reference Company may not be reflective of distribution companies operating in Brazil and thus, underestimate true operating costs. These costs which include certain taxes and other issues are being discussed under administrative appeal with ANEEL. In addition, the distribution companies are challenging certain methodologies used for the tariff revision. For example, the rate base calculation used for the tariff reset, defined by ANEEL Resolution 493, takes into account the replacement value of the concessionaire s assets. Private investors are pursuing a claim in the Brazilian courts, arguing that the minimum bid price established during the privatization process should be used as the asset base for these calculations. There is no assurance that these arguments will be successful. Although ANEEL has approved the asset base calculation used by the regulators for many distribution companies, it has not reached a final determination for Eletropaulo, so a provisional asset base number, based on 90% of the fixed assets adjusted for inflation until June 2003 (approximately R$5.2 billion), was used. ANEEL has stated that once the final rate base is established pursuant to Resolution 493, tariffs will be retroactively calculated and adjusted in the 2005 tariff adjustment. There is no assurance at this point on what the final rate base amounts will be for AES Eletropaulo. In the case of AES Sul, the final rate base was established by ANEEL as R$671 million and its effects were considered in the 2004 tariff adjustment process. Finally, in 2003, ANEEL released a technical note with changes to the original Resolution 493. In August 2003, AES Eletropaulo and AES Sul filed an administrative appeal against the technical note, contesting the changes in the resolution as well as inconsistencies noted in the original version of Resolution 493 that was not accepted by ANEEL.

New Power Sector Model. The Federal Government has been carrying out a wide reform in the Brazilian power sector and on December 11, 2003, announced a proposed new model for the Brazilian power sector and enacted Provisional Measures #144 and #145, which set forth the basic rules that will govern the new 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:

- Creates two energy commercialization environments: the regulated contractual environment (ACR), intended for the distribution companies and 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 PROINFA Brazilian Renewable Energy Incentive Program); pre-existing purchases made before Law #10848/04; and purchases from Itaipu.

- Distribution utilities can pass through the amounts contracted, up to 103% of their load, conditioned upon the amendment of the concession contracts: ANEEL will adopt a new pass-through methodology in the annual tariff adjustment; and variations of the energy purchase costs will be contemplated in the tracking account (CVA).

The Electric Energy Commercialization Chamber (CCEE) successor of the Wholesale Energy Market (MAE) carried out, on December 7, 2004, the largest auction in the country s history, in which power distribution utilities bought energy to serve 100% of their markets projected for 2005, 2006 and 2007. The energy traded in this auction will be the object of contracts lasting eight years starting from 2005, 2006 and 2007.

Several aspects of the New Power Sector Model depend on legal regulation (decrees, orders, or resolutions) and the Brazilian government is associating the rights for the CVA of energy purchased from the auction to the signature of amendments to concession contracts. This can represent risk relating to certain aspects of the current IRT methodology.

Challenges to the Constitutionality of the New Industry Model Law. The New Industry Model Law is currently being challenged on constitutional grounds before the Brazilian Supreme Court. The Federal Government moved to dismiss the actions arguing that the constitutional challenges were moot because they related to a provisional measure that had already been converted into law. However, on August 4, 2004, the Brazilian Supreme Court denied the government s motion and decided to hear the actions and rule on their merits. In addition, one Justice held that a relevant portion of the New Industry Model Law was unconstitutional and another asked to review the trial records, thus suspending the hearing. A final decision on this matter is subject to majority vote of the 11 Justices, provided that a quorum of at least eight Justices must be present. To date, the Brazilian Supreme Court has not reached a final decision and we do not know when such a decision may be reached. Therefore, the New Industry Model Law is currently in force. Regardless of the Supreme Court s final decision, certain portions of the New Industry Model Law relating to restrictions on distributors performing activities unrelated to the distribution of electricity, including sales of energy by distributors to free consumers and the elimination of contracts between related parties are expected to remain in full force and effect.

If all or a portion of the New Industry Model Law is determined unconstitutional by the Brazilian Supreme Court, the regulatory scheme introduced by the New Industry Model Law may not come into effect, generating uncertainty as to how and when the Federal Government will be able to introduce changes to the electric energy sector. We have already purchased a significant portion of our electricity needs through 2016, and the pass-through to tariffs of such electricity is expected to continue to be governed by the regulation in effect on the date of the purchase. As such, irrespective of the outcome of the Supreme Court s decision, we believe that in the short term, the effects of any such decision on our activities will be limited. Nevertheless, the exact effect of an unfavorable outcome of the legal proceedings on us is difficult to predict and it could have an adverse impact on our business and results of operations.

Cameroon. The law governing the electricity sector was passed and promulgated in December 1998, which defines the new institutional organization of 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 and exportation as well as electricity sales activities.

The mission of the Electricity Sector Regulatory Board (ARSEL) involves regulating and ensuring the proper functioning of the electricity sector, maintaining its economic and financial balance and safeguarding 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 Ministry 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 constitute a grace period to permit resolution of issues existing at the time of the privatization, and all penalties are waived. In 2004, AES SONEL and the Cameroonian Government started renegotiating the concession contract. The issues included in this renegotiation process are: the quality of services requirements, the connection targets, the tariff formulation, the obligation of developing new generation capacity and the penalties regime.

Chile. In Chile, the regulation of production schedules for electricity generation facilities is based on the marginal cost of production, which is the cost of the most expensive unit required by the system at the time. The spot price among generation companies for both electrical capacity (the amount of electricity available at any point in time) and electrical energy (the amount of electricity produced or consumed over a period of time) is also the marginal cost of production. Chile has four electricity systems. The major two interconnected electricity systems are the SIC and the SING, which cover almost 97% of the population of the country.

In order to meet demand for electricity at any point in time, the lowest marginal cost generating plant in an interconnected system is used before the next lowest marginal cost plant is dispatched. As a result, at any specific level of demand, the appropriate supply will be provided at the lowest possible marginal cost of production available in the system. 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 production in the system, if the contracting generation company s marginal cost is above that of the last generator required to meet demand at the time.

According to existing law, during periods when production cannot meet system demands, regardless of whether the government has enacted a rationing decree, the price of energy exchanges among generation companies is valued at the unserved energy cost or shortage cost which is the cost to consumers for not having energy available. This law remained untested until November 1998 when generators in the SIC were unable to agree on the implementation of the shortage cost during the supply deficit and associated mandated rationing periods. The matter was referred to the Ministry of Economy, which in March 1999 ruled the application of the shortage cost. Based on this decision, generators with energy deficits at the time were required to pay companies with energy surpluses the shortage cost or corresponding spot price equal to the cost of unserved energy for energy purchases during that period. The prices paid to generation companies by distribution companies for capacity and energy to be resold to their retail customers are based on the expected average marginal cost of capacity or energy. In order to ensure price stability, however, the regulatory authorities in Chile establish prices, known as node prices every six months to be paid by distribution companies for the energy and capacity requirements of regulated consumers. 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 5%, node prices are adjusted upward or downward, as the case may be, so that the difference between such prices equals 5%. In contrast, the spot price paid by one generation company to another for energy is referred to as the system marginal cost, which is based on the actual marginal cost of the highest cost generator producing electricity in the system during the relevant period, as determined on an hourly basis.

Since the system marginal cost for energy is set weekly (but may in certain circumstances be changed on a daily basis) based on variables that can change on an instantaneous basis, and the node price for energy is set every six months based on projections of these variables over the next 24 to 48 months, in the case of the SIC and SING, the system marginal cost for energy of a system tends to be more volatile than the node price for energy of that system. In periods of low water conditions that require greater generation of energy by more costly thermoelectric plants, the system marginal cost typically exceeds the node price. In periods of high water conditions when lower cost hydroelectric facilities can meet the majority of demand, the system marginal cost is typically below the node price and may in fact decline to zero at some hours.

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 our position with regard to both our 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 called for restrictions on natural gas exports to Chile in order to conserve gas reserves for domestic use. Between April and June 2004, daily restrictions on exports to Chile fluctuated between 20% and 47% of contracted volumes, depending on domestic demand. In June 2004, after weeks of negotiations, Argentina agreed to reduce the peak restriction level to 61.4 million cubic feet per day (Mmcf/d), down from 423 Mmcf/d in May 2004. Our subsidiary Electrica Santiago 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. TGN is currently experiencing financial difficulties. 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.

Dominican Republic. The electric sector in the Dominican Republic has evolved from a state owned system, to a reform period from 1997 through 1999 which was regulated by the Ministry of Industry and Commerce without an overall plan, and finally, with the passage of the General Electricity Law No. 125-01 on July 26, 2001, into a system with more concise rules, governed by 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, the Dominican Republic was shaken by a severe economic, financial and political crisis, caused mainly by the status of the public finances and the bankruptcy of the three main commercial banks. Although the electrical sector has been vulnerable for years, it was this economic downturn and an increase in fuel prices that essentially 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. There are no assurances that these issues will be resolved in favor of the Company.

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 that requires multilateral lending to reconstitute the sector.

Venezuela. The Electric Service Law enacted on September 17, 1999, contemplates the restructuring of the entire regulatory system for the electric sector in Venezuela by defining separation of activities, the functions of some of the current entities that regulate the sector, introduces new entities and eliminates

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others that had regulatory authority over the electric sector. The introduction of this new regulatory regime is expected to be gradual. Certain elements of the old regulatory regime will remain, particularly the tariff regime, while the new entities and regulations to be created under the Electric Service Law are adopted.

On December 14, 2000, the Government issued regulations which provide the mechanism for the implementation of the Electric Service Law and establish the general regulatory framework for Venezuela s electricity sector relating to, among other things, the free market for generation, the segregation of generation, transmission, distribution and commercialization activities, concessions for existing distribution companies and public auctions for new distribution concessions. The Ministerio de Energia y Minas (MEM) is the principal regulatory authority of the electric sector in Venezuela. The MEM is responsible for, among other things: coordinating the activities of the government bodies responsible for administering the regulatory system, planning the development of the electric sector, granting concessions for distribution and transmission activities and executing the respective contracts and, in conjunction with the Ministerio de Production y Comercio (MPC), adopting tariff rates for distribution activities. The Electric Service Law also contemplates the creation of the Comisión Nacional de Energía Electrica (CNEE) to regulate the electricity sector in Venezuela. The CNEE is expected to be an agency under the MEM with functional, administrative and financial autonomy. Once established, it is expected that the CNEE will gradually take over the functions now being conducted by the Fundación para el Desarrollo del Servicio Eléctrico (FUNDELEC). The Electric Service Law also contemplates the creation of a centralized, state-owned company, the Centro Nacional de Gestión del Servicio Eléctrico (CNGSE), to administer the dispatch of electricity nation-wide. The CNGSE will replace the functions that have been historically assumed by the electricity companies through the Interconnection Contract and administrated by the Oficina de Planificación del Sistema Interconectado (OPSIS). While the CNGSE is being organized, OPSIS will continue to operate and control the dispatch of electricity under the terms of the Interconnection Agreement.

The Electric Service Law introduces a complete revision of the manner in which electric services are to be remunerated. Distribution and transmission activities will be regulated and their remuneration will be governed by a tariff regime to be implemented by the MEM in conjunction with the MPC. The Electric Service Law provides that, until a new tariff regime is put in place by the MEM, the current tariff regime, set forth in Decree 368 and the 1999 Resolution, will continue to be in effect. These basic tariff rates are subject to semi-annual and monthly adjustments to reflect changes in the inflation and currency exchange rates and the prices of energy and combustible fuels, respectively. However, since price controls were established in the country in 2004, the Government has not permitted EDC to adjust its tariff rates to reflect inflation.

The failure by the Government in future periods to allow EDC to adjust its tariff rates could have a material adverse effect on its financial condition, results of operations, business prospects and, ultimately, its ability to satisfy its obligations. In addition, the tariff review and setting process in Venezuela is subject to political and regulatory uncertainty, and no assurance can be given as to the outcome of the process or whether it will result in an acceptable rate of return for EDC.

Ukraine. Restructuring of the Ukrainian electrical energy sector and improvement of its functioning and development of a market began in 1995. Until that time the electrical energy sector was functioning as a single vertically integrated system operated by the Ministry of Energy and Electrification. In April 1995, the President of Ukraine issued Decree No. 282/95 On the Restructuring in Electrical Energy Complex of Ukraine, by which the vertically integrated system was separated into generation, local distribution and high voltage transmission. The local distribution and supply services were placed into 27 regionally defined operating companies (called oblenergos). The Ministry of Energy and Electrification remained as a policy agency, and also controlled shares (assets) of state joint stock companies.

In March 1995, the President of Ukraine created the National Regulatory Energy Commission (NREC), the main purpose of which was to ensure the effective functioning of the electric energy sector and the formation of an electric energy market. In 1997, the Law On the Energy Sector defined the NREC as a regulatory body in the energy sector and specified principles of such regulation, including: licensing of activities in the energy sector; tariff policy formation; development of a competitive framework; and customers rights protection.

In 1996, NREC approved the Wholesale Electricity Market (WEM) Members Agreement. As a result, transactions for power and energy sales from the generating companies to the supply companies were structured through a wholesale electricity market modeled on the early version of the British power pool.

The Law of Ukraine On the Energy Sector adopted in 1997 became the first legislative act, regulating relationships relating to electricity generation, transmission, supply and consumption, competition in the sector, customers rights protection and ensuring energy safety of Ukraine. In June 2000, amendments to the Law of Ukraine On the Energy Sector were passed, which obligated customers to make cash payments for consumed electricity into special bank accounts. Allocations of funds from the special bank accounts to sector entities are made based on a fund allocation procedure issued by the NREC. By the end of 2004, cash collections had recovered to a level in the 97% range from 27% in 2000.

In 2002, the Cabinet of Ministers of Ukraine approved the Concept of WEM Development, laying out foundations for further market development in three stages over several years, leading to replacement of the current single buyer market model with bilateral contracts between suppliers and generators, and between end-users and generators, as well as a balancing market. The Concept also addresses current power sector problems such as administrative interference in market operations and cash flows, cross-subsidization through retail and wholesale tariff structures, non-payment, and debt accumulation, in order to improve the overall investment climate. In June 2004, a special commission created by the government approved a plan of measures for the WEM Concept Implementation. The plan sets out a list of legislative acts, which have to be drafted or amended, and responsible agencies for that work.

Hungary. In 2004, in connection with the accession of Hungary as a member state of the European Union, the Hungarian government (the Government) provided notification to the European Commission (the Commission) under the Commission state aid rules of certain arrangements entered into between the Government and the state owned electricity wholesaler, MVM. The Commission is conducting a preliminary investigation of the identified arrangements to determine whether or not any alleged Government aid provided pursuant to arrangements satisfied the conditions for a finding of compatibility with the common market. If the Commission determines to open a formal investigation, AES Tisza would not be a named party to such an investigation, but could be adversely affected in the event that the Commission was to conclude that AES Tisza was the beneficiary of unlawful state aid. While we believe there is a likelihood of a formal investigation, it is too early to predict the outcome.

Environmental and Land Use Regulations

Overview. We have ownership interests in generation and distribution assets in the U.S. and many other countries and we are therefore subject to various international, U.S., national, federal, 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 we do business has separate laws and regulations governing operation of power generation and distribution assets, including laws relating to the siting, construction, permitting, ownership, operation, modification, repair and decommissioning of, and power sales from, such assets. In addition to such laws and regulations, international projects funded by the

World Bank are subject to World Bank environmental standards, which tend to be more stringent than local country standards. Whenever feasible, AES attempts to use advanced environmental technologies (such as CFB coal technologies or advanced gas turbines) in our non-U.S. businesses in order to minimize environmental impacts.

Environmental laws and regulations affecting power generation and distribution are complex, change frequently and have tended to become more stringent over time. We have incurred and will continue to incur capital costs and other expenditures in order to comply with environmental laws and regulations, in particular, with respect to the laws and regulations described below. See Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Resources and Liquidity for more detail. If environmental and land use regulations change in the future, we may be required to make significant capital or other expenditures. There can be no assurance that we would be able to recover from our customers some or all costs to comply with such environmental or land use regulations or 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 we have 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.

Air Emissions. The U.S. Clean Air Act and various state laws and regulations regulate emissions of major air pollutants, including sulfur dioxide (SO_2), nitrogen oxides (NO_x) and particulate matter (PM) in the U.S. The Environmental Protection Agency s (EPA) NO_x state implementation plan (NO_x SIP Call) required operators of coal-fired electric generating facilities in 22 U.S. states and the District of Columbia either (i) to reduce their NO_x emissions to levels allocated under the plan or (ii) to purchase NO_x emissions allowances from other operators in order to meet allocated emissions levels by May 31, 2004. We are in the process or have completed installing selective catalytic reduction (SCR) and other NO_x control technologies at three facilities of our subsidiary, Indianapolis Power and Light (IPL) in response to NO_x 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, named the Clean Air Interstate Rule (CAIR), was issued on March 10, 2005 and requires significant reductions of SO_2 and NO_x emissions from existing power plants located in 28 eastern states and the District of Columbia. The required emission reductions will be in two phases with the first phase beginning in 2009 and 2010 for NO_x and SO_2, respectively, and a second phase with increased required reductions in both air pollutant emissions beginning in 2015. The second rule, called the Clean Air Mercury Rule , was issued on March 15, 2005 and requires reductions of mercury emissions from coal-fired power plants. This rule requires mercury emission reductions from most U.S. 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. The Clean Air Mercury Rule also establishes stringent mercury emission performance standards for new coal-fired power plants.

For these two new rules, the states will be establishing emission allowance-based NO_x, SO_2 and mercury emission cap-and-trade programs to implement the required emission reductions. While the exact impact and cost of these two new rules cannot be established until the states complete assigning emission allowances to our affected facilities, there can be no assurance that our business, financial conditions or results of operations would not be materially and adversely affected by these new rules.

IPL has made and will incur substantial environmental capital expense as part of the efforts to comply with these anticipated SO_2, NO_x, and mercury rules. SCR systems for NOx controls have already been installed on certain units and one additional SCR will be installed at another IPL unit in 2005. On November 30, 2004, the Indiana Utility Regulatory Commission approved rate-based construction of additional clean coal technology equipment up to $182 million. These capital expenditures will be directed at SO_2, NO_x and mercury emissions reductions from IPL s power plants and at reductions of fine PM pollution in the atmosphere. IPL currently estimates total additional capital expenditures related to emissions reductions in 2005, 2006 and 2007 of $55 million, $86 million and $92 million, respectively.

The New York State Department of Environmental Conservation (NYSDEC) recently adopted 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 NO_x reduction requirements year-round, rather than just during the summertime ozone season. As a result, in order to operate our four generation facilities located in New York, installation of pollution control technology will likely be required. See Item 3 Legal Proceedings, for a description of a recent Consent Decree that includes provisions related to emissions at these facilities.

Poor ozone air quality in the Houston-Galveston, Texas area has resulted in the creation of a regional NO_x cap-and-trade program. This program would impact the AES Deepwater petroleum coke-fired power plant by allocating it insufficient NOx allowances which would make it impossible economically for the plant to operate past 2006. In response to the implementation of this program, AES has planned a $30 million environmental capital project at AES Deepwater, which includes adding an SCR NO_x control system by May 2007, thereby enabling AES Deepwater to economically operate past 2006.

In July 1999, EPA published (the Regional Haze Rule) to reduce haze and protect visibility in designated federal areas. On April 15, 2004, EPA proposed amendments to the Regional Haze Rule that would, among other things, set guidelines for determining when to require the installation of best available retrofit technology, 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 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 between 2004 and 2008, depending on whether and when the EPA determines that state is in attainment or non-attainment of PM air quality standards.

Various members of Congress have proposed new legislation that, if passed into law, could require reductions in power plant air emissions beyond the requirements described above. President Bush supports Clear Skies legislation that would cap emissions of three pollutants (NOx, SO_2 and mercury), with voluntary reductions of CO_2. In January 2005, Senators Inhofe and Voinovich introduced a version of the Clear Skies Act that included caps on NO_x, SO_2 and mercury emissions but did not include a cap (voluntary or otherwise) on CO_2. On March 9, 2005, the Senate Environmental Committee rejected the proposed Clear Skies legislation. Several Committee members have requested future analysis and information, which is likely to significantly delay any reconsideration of the proposed legislation this year.

In Europe we are, and will continue to be, required to reduce air emissions from our facilities to comply with applicable European Union (EU) Directives, including the Large Combustion Plant Directive (the LCPD), which sets emissions standards for NO_x, SO_2, and PM for large-scale industrial combustion facilities for all member states. As of June 2004, coal plants were required to opt-in or opt-out of the LCPD emissions standards. Those facilities that opted out must cease all operations by 2015, and may not operate for more than 20,000 hours after 2008. Those that opt-in, like our AES Kilroot facility, in the United Kingdom must invest in abatement technology to achieve specific SO_2 reductions. AES Kilroot plans to incur costs of $21 million during 2005, and total cumulative costs of approximately

$88 million. AES s other coal plants in Europe have also opted-in but will not need to implement any additional abatement technology.

In July 2003, the EU Directive on Greenhouse Gas (GHG) Emission Allowance Trading (the Directive) was adopted. Pursuant to the Directive, a CO_2 emissions cap-and-trade program known as the EU Emissions Trading Scheme (EU-ETS) was created, which requires member states to limit emissions of CO_2 within their countries. To do so, member states will be required to implement EU approved National Allocation Plans (NAPs). Under the NAPs, member states will be responsible for allocating limited CO_2 allowances within their borders. The EU-ETS does not dictate how these allocations are to be made and NAPs that have been submitted thus far have varied their approaches to sector allocation and allocation methodologies. For these and other reasons, there remain significant uncertainties regarding the application of the EU-ETS. Based on our current analyses, we expect that certain AES businesses will be under-allocated and others will be over-allocated. At present, we cannot predict whether compliance with the EU-ETS 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 (Kyoto) became effective. Kyoto requires countries that have ratified it to substantially reduce their GHG emissions including CO_2. AES has generation operations in seven countries that have ratified Kyoto; however, we do not expect Kyoto implementation to have a material impact on our revenues or projected earnings during the 2008-2012 period. Over the course of the next several years, as decisions surrounding implementation of Kyoto become more detailed, we will have a better understanding of the impact of Kyoto on the Company. At present, we cannot predict whether compliance with Kyoto will have a material impact on our operations or results.

Water Emissions. Our facilities are subject to a variety of rules governing water discharges. In particular, we are evaluating the impact of the U.S. Clean Water Act Section 316(b) rule regarding cooling water intake. To protect fish and other aquatic organisms, the rule requires existing steam electric generating facilities to utilize the best technology available for cooling water intake structures. We believe that many of our facilities will be affected by this rule. To comply, we must first prepare a Comprehensive Demonstration Study to assess each facility s effect on the local aquatic environment. Because 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. At present, however, we cannot predict whether compliance with the 316(b) rule will have a material impact on our operations or results.

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/A, 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 September 1999, a judge in the Brazilian appellate state court of Minas Gerais 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 CEMIG. AES 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

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agreement invalid where it purported to grant SEB the Special Rights and enjoined the exercise of Special Rights. In August 2001, the state appellate court denied an appeal of the merits decision, and extended the injunction. In October 2001, SEB filed two appeals against the decision on the merits of the state appellate court, one to the Federal Superior Court and the other to the Supreme Court of Justice. The state appellate court denied access of these two appeals to the higher courts, and in August 2002, SEB filed two interlocutory appeals against such decision, one directed to the Federal Superior Court and the other to the Supreme Court of Justice. These appeals continue to be pending. SEB intends to vigorously pursue by all legal means a restoration of the value of its investment in CEMIG; however, there can be no assurances that it will be successful in its efforts. Failure to prevail in this matter may limit the SEB s influence on the daily operation of CEMIG.

In November 2000, the Company was named in a purported class action suit along with six other defendants, alleging unlawful manipulation of the California wholesale electricity market, 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 back 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 asserted the claims asserted in the earlier action and names AES, AES Redondo Beach, L.L.C., AES Alamitos, L.L.C., and AES Huntington Beach, L.L.C. as defendants. In May 2002, the case was removed by certain cross-defendants from the San Diego County Superior Court to the United States 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 United States Court of Appeals for the Ninth Circuit. On December 8, 2004, a panel of the Ninth Circuit issued an opinion affirming in part and reversing in part the decision of the District Court, and permitting the remand of the case to state court. The Company believes that it has meritorious defenses to any actions asserted against us and expects that we will defend ourselves vigorously against the allegations.

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 have involved alleged market manipulation. The FERC has requested documents from each of the AES Southland plants and AES Placerita. AES Southland and AES Placerita have cooperated fully with the FERC investigation. AES Southland is not subject to refund liability because it did not sell into the organized spot markets due to the nature of its tolling agreement. The Ninth Circuit Court of Appeals however also addressed the appeal of the FERC s decision not to impose refunds for the alleged failure to file rates including transaction specific data for sales to the California Independent System Operator (ISO) for 2000 and 2001. See *State of California ex rel. Bill Lockye.* In its order issued September 9, 2004, the Ninth Circuit did not order refunds, but remanded the case to the FERC for a refund proceeding to consider remedial options. Placerita made sales during the referenced time period. Depending on the method of calculating refunds and the time period to which the method is applied, the alleged refunds sought from AES Placerita could approximate $23 million.

In November 2002, the Company was served with a grand jury subpoena issued on application of the United States Attorney for the Northern District of California. The subpoena sought, inter alia, certain categories of documents related to the generation and sale of electricity in California from January 1998 to the date of the subpoena. The Company cooperated in providing documents in response to the subpoena.

In July 2001, a petition was filed against CESCO, an affiliate of the Company, by the Grid Corporation of Orissa, India (Gridco), with the Orissa Electricity Regulatory Commission (OERC), alleging that CESCO had defaulted on its obligations as a government licensed distribution company, that

CESCO management abandoned the management of CESCO, and asking for interim measures of protection, including the appointment of a government regulator to manage CESCO. Gridco, a state owned entity, is the sole energy wholesaler to CESCO. In August 2001, the management of CESCO was handed over by the OERC to a government administrator that was appointed by the OERC. By its order of August 2001, the OERC held that the Company and other CESCO shareholders were not proper parties to the OERC proceeding and terminated the proceedings against the Company and other CESCO shareholders. 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 as to why CESCO s distribution license should not be revoked. In response, CESCO submitted a business plan to the OERC. On February 26, 2005, the OERC issued an order rejecting the proposed business plan. The order also stated 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. Gridco also has asserted that a Letter of Comfort issued by the Company in connection with the Company s investment in CESCO obligates the Company to provide additional financial support to cover CESCO s financial obligations. In December 2001, a notice to arbitrate pursuant to the Indian Arbitration and Conciliation Act of 1996 was served on the Company by Gridco pursuant to the terms of the CESCO Shareholder s Agreement (SHA), between Gridco, the Company, AES ODPL, and Jyoti Structures. The parties have filed their respective statement of claims, counter claims, defenses and answers. 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. A hearing on the merits has been scheduled for August 2005. Other matters that had been pending before the Indian courts were resolved with the exception of a petition before the Indian Supreme Court concerning fees of the third neutral arbitrator and the venue of future hearings. Although Gridco appears to allege damages of approximately $190 million plus undisclosed penalties and interest, Gridco has failed to provide explanations for such damages. The Company believes that it has meritorious defenses to any actions asserted against it and expects that it will defend itself vigorously against the allegations.

In April 2002, IPALCO and certain former officers and directors of IPALCO were named as defendants in a purported class action lawsuit filed in the United States District Court for the Southern District of Indiana. On May 28, 2002, an amended complaint was filed in the lawsuit. The amended complaint asserts that IPALCO and former members of the pension committee for the Indianapolis Power & Light Company thrift plan 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 December 2002, plaintiffs moved to certify this case as a class action. The Court granted the motion for class certification on September 30, 2003. On October 31, 2003, the parties filed cross-motions for summary judgment on liability. Those motions currently are pending before the Court. IPALCO believes it has meritorious defenses to the claims asserted against it and intends to defend this lawsuit vigorously.

In July 2002, the Company, Dennis W. Bakke, Roger W. Sant, and Barry J. Sharp were named as defendants in a purported class action filed in the United States District Court for the Southern District of Indiana. In September 2002, two virtually identical complaints were filed against the same defendants in the same court. All three lawsuits purport to be filed on behalf of a class of all persons who exchanged their shares of IPALCO common stock for shares of AES common stock issued pursuant to a registration statement dated and filed with the SEC on August 16, 2000. The complaints purport to allege violations of Sections 11, 12(a)(2) and 15 of the Securities Act of 1933 based on statements in or omissions from the registration statement concerning certain secured equity-linked loans by AES subsidiaries; the supposedly volatile nature of AES stock, as well as AES s allegedly unhedged operations in the United Kingdom at that time, and the alleged effect of the New Electrical Trading Agreements (NETA) on AES s United Kingdom operations. On April 14, 2003, lead plaintiffs filed an amended and consolidated complaint, which added former IPALCO directors and officers John R. Hodowal, Ramon L. Humke and John R. Brehm as defendants and, in addition to the purported claims in the original complaint, purports to allege

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against the newly added defendants violations of Sections 10(b) and 14(a) of the Securities Exchange Act of 1934 and Rules 10b-5 and 14a-9 promulgated thereunder. The amended complaint also purports to add a claim based on alleged misstatements or omissions concerning an alleged breach by AES of alleged obligations AES owed to Williams Energy Services Co. (Williams) under an agreement between the two companies in connection with the California energy market. On September 26, 2003, defendants filed a motion to dismiss the amended and consolidated complaint. By Order dated November 17, 2004, the Court dismissed all of the claims asserted in the amended and consolidated complaint against all defendants with one exception. The exception consists of claims against Bakke, Sant, Sharp and AES (the AES Defendants), under Sections 11, 12 and 15 of the Securities Act of 1933 (the Securities Act), 15 U.S.C. §§ 77k, 77l and 77o, based on the alleged failure of the Registration Statement and Prospectus disseminated to the IPALCO stockholders for purposes of the Share Exchange to disclose AES s purported temporary default on its contract with Williams. On December 15, 2004, the AES Defendants filed a motion for judgment on the pleadings dismissing the remaining claims. The Company and the individual defendants believe that they have meritorious defenses to the claims asserted against them and intend to defend these lawsuits vigorously.

In October 2002, the Company, Dennis W. Bakke, Roger W. Sant and Barry J. Sharp were named as defendants in purported class actions filed in the United States District Court for the Eastern District of Virginia. Between October 29, 2002 and December 11, 2002, seven virtually identical lawsuits were filed against the same defendants in the same court. The lawsuits purport to be filed on behalf of a class of all persons who purchased the Company s common stock and certain of its bonds between April 26, 2001 and February 14, 2002. The complaints purport to allege violations of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, and Rule 10b-5 promulgated thereunder based on statements or omissions concerning the Company s United Kingdom operations and the alleged effect of the NETA on those operations. On January 16, 2003, the Court granted defendants motion to transfer the actions to the United States District Court for the Southern District of Indiana. On September 26, 2003, plaintiffs filed a single consolidated amended class action complaint on behalf of a purported class of all persons who purchased the Company s common stock and certain of its bonds between July 27, 2000 and November 8, 2002 (the Imler Action). The consolidated amended class action complaint, in addition to asserting the same claims asserted in the original complaints, also purports to allege that AES and the individual defendants failed to disclose information concerning AES s role in purported manipulation of the California electricity market, the effect thereof on AES s reported revenues, and AES s purported contingent legal liabilities as a result thereof, in violation of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 and Rule 10b-5 promulgated thereunder. Defendants filed a motion to dismiss on November 17, 2003. On October 1, 2004, the parties filed a Stipulation and Agreement of Settlement pursuant to which defendants caused to be paid a total of $5 million into a settlement fund to settle, as defined in the stipulation, all claims arising out of this action and a related action captioned *Moskal v. The AES Corporation, et al.*, 1:03-CV-0284. Defendants settled the lawsuits without any admission or concession of any liability or wrongdoing or lack of merit in their defenses. On January 28, 2005, the Court entered an order granting final settlement.

Commencing on May 2, 2003, the Indiana Securities Commissioner of Indiana s Office of the Secretary of State, Securities Division, pursuant to Indiana Code 23-2-1, served subpoenas on 30 former officers and directors of IPALCO Enterprises, Inc. (IPALCO), AES, and others, requesting the production of documents in connection with the March 27, 2001 share exchange between the Company and IPALCO pursuant to which stockholders exchanged shares of IPALCO common stock for shares of the Company s common stock and IPALCO became a wholly-owned subsidiary of the Company. IPALCO and the Company have produced documents pursuant to the subpoenas served on them. In addition, the Indiana Securities Commissioner s office has taken testimony from various individuals. On January 27, 2004, Indiana s Secretary of State issued a statement which provided that the investigative staff had determined that there did not appear to be a justifiable reason to focus further specific attention upon six

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non-employee former members of IPALCO s board of directors. The investigation otherwise remains pending. In addition, although the press release characterized the investigation as criminal, the Company and IPALCO do not believe that the Indiana Securities Commissioner has criminal jurisdiction, and the Company and IPALCO are unaware at this time of any participation by any government office or agency with such jurisdiction.

In November 2002, a lawsuit was filed against AES Wolf Hollow, L.P. (AESWH) and AES Frontier, L.P. (AESF), two of our indirect subsidiaries, in the District Court of Hood County, Texas by Stone & Webster, Inc. (S&W). At the time of filing, AESWH and AESF were two indirect subsidiaries of the Company. In December 2004, the Company finalized agreements to transfer the ownership of AESWH and AESF. S&W contracted to perform the engineering, procurement and construction of the Wolf Hollow project, a gas-fired combined cycle power plant in Hood County, Texas. In its initial complaint, S&W requested a declaratory judgment that a fire that took place at the project on June 16, 2002 constituted a force majeure event and that S&W was not required to pay rebates assessed for associated delays. As part of the initial complaint, S&W also sought to enjoin AESWH and AESF from drawing down on letters of credit provided by S&W. The Court refused to issue the injunction. S&W has since amended its complaint four times and joined additional parties, including the Company and Parsons Energy & Chemicals Group, Inc. In addition to the claims already mentioned, the current claims by S&W include claims for breach of contract, breach of warranty, wrongful liquidated damages, foreclosure of lien, fraud and negligent misrepresentation. In January 2004, the Company filed a counterclaim against S&W and its parent, the Shaw Group, Inc. (Shaw). Although S&W has yet to provide a detailed damage claim, it has filed a lien against AESWH and AESF, with each lien allegedly valued at approximately $70 million. In March 2004, S&W and Shaw each filed an answer to the counterclaim. The counterclaim and answers subsequently were amended. In March 2005, the Court rescheduled the trial date for October 24, 2005. The Company and subsidiaries believe that the allegations in S&W s complaint are meritless, and that each defendant has meritorious defenses to the claims asserted by S&W. They each intend to defend the lawsuit vigorously.

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 BNDES financings provided to AES Elpa and AES Transgas and the rationing loan provided to AES Eletropaulo, changes in the control of AES Eletropaulo, sales of assets by AES Eletropaulo and the quality of service provided by AES Eletropaulo to its customers and requested various documents from AES Eletropaulo relating to these matters. In October 2003 this inquiry was sent to the MPF for continuing investigation. Also in March 2003, the Commission for Public Works and Services of the Sao Paulo Congress requested AES Eletropaulo to appear at a hearing concerning the default by AES Elpa and AES Transgas on the BNDES financings and the quality of service rendered by AES Eletropaulo. This hearing was postponed indefinitely. In addition, in April 2003, the office of the MPF notified AES Eletropaulo that it is conducting an inquiry into possible errors related to the collection by AES Eletropaulo of customers unpaid past-due debt and requesting the company to justify its procedures. In December 2003, ANEEL answered, as requested by the MPF, that the issue regarding the past-due debts are to be included in the analysis to the revision of the General Conditions for the Electric Energy Supply.

In May 2003, there were press reports of allegations that in April 1998 Light Serviços de Eletricidade S.A. (Light) colluded with Enron in connection with the auction of AES Eletropaulo. Enron and Light were among three potential bidders for AES Eletropaulo. At the time of the transaction in 1998, AES owned less than 15% of the stock of Light and shared representation in Light s management and Board with three other shareholders. In June 2003, the Secretariat of Economic Law for the Brazilian Department of Economic Protection and Defense (SDE) issued a notice of preliminary investigation seeking information from a number of entities, including AES Brasil Energia, with respect to certain allegations arising out of the privatization of AES Eletropaulo. On August 1, 2003, AES Elpa responded on behalf of AES-affiliated companies and denied knowledge of these allegations. The SDE began a follow-up administrative proceeding as reported in a notice published on October 31, 2003. In response to the Secretary of Economic Law s official letters requesting explanations on such accusation, AES Eletropaulo filed its defense on January 19, 2004. In June 2004, a request for further information was received by AES Eletropaulo.

AES Florestal, Ltd., (Florestal) a wholly-owned subsidiary of AES Sul, is a wooden utility pole factory located in Triunfo, in the state of Rio Grande do Sul, Brazil. In October 1997, AES Sul acquired Florestal as part of the original privatization transaction by the Government of the State of Rio Grande do Sul, Brazil, that created AES Sul. From 1997 to the present, the chemical compound chromated copper arsenate has been used by Florestal to chemically treat the poles under an operating license issued by the Brazilian government. Prior to the acquisition of Florestal by AES Sul, another chemical, creosote, was used to treat the poles. After acquiring Florestal, AES Sul discovered approximately 200 barrels of solid creosote waste on the Florestal property. In 2002 a civil inquiry (Civil Inquiry No. 02/02) was initiated and a criminal lawsuit was filed in the city of Triunfo s Judiciary both by the Public Prosecutors office of the city of Triunfo. The civil lawsuit was settled in 2003. The criminal lawsuit has been suspended for a period of two years pending a certification of environmental compliance for Florestal and the occurrence of no further violations of environmental regulations. Florestal has hired an independent environmental assessment company to perform an environmental audit of the entire operational cycle at Florestal. Florestal submitted a preliminary action plan that the environmental authority is reviewing. Florestal continues to review and evaluate the site and to determine if any additional remedial actions are necessary.

On January 27, 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., 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. On February 10, 2004, the Company filed in the First Instance Court of the National District of the Dominican Republic (Court) an action seeking injunctive relief based on several constitutional due process violations contained in the Formulation of Charges (Constitutional Injunction). On or about February 24, 2004, the Court granted the Constitutional Injunction and ordered the immediate cease 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. On March 1, 2004, the Superintendence of Electricity appealed the Court s decision. The appeal is pending.

In late July 2004, the Corporación Dominicana de Empresas Eléctricas Estatales (CDEEE), which is the government entity that currently owns 50% of Empressa Generadora de Electricidad Itabo, S.A. (Itabo), filed separate lawsuits in the Dominican Republic against Ede Este, a former subsidiary of AES, and Itabo S.A, an AES affiliate, with the lawsuit against Itabo also naming as a defendant the president of Itabo. In the action against Itabo, CDEEE requests a rendering of accountability for the accounts of Itabo with regard to all transactions between Itabo and related parties. On September 29, 2004, the Court rejected CDEEE s request. CDEEE also requests that the court order Itabo to deliver its accounting books and records for the period from September 1999 to July 2004 to CDEEE, and that an independent expert audit the accounting records and present a report to CDEEE and the court. In the Ede Este lawsuit, CDEEE requests a rendering of accountability of the accounts of Itabo of all Ede Este´s commercial and financial operations with affiliate companies since August 5, 1999. On February 9, 2005, Itabo filed a lawsuit against CDEEE and the Fondo Patrimonial para el Desarrollo (FONPER) seeking among other relief, to enforce the arbitration/dispute resolution processes set forth in the contracts among the parties.

On February 18, 2004, AES Gener S.A. (Gener SA), a subsidiary of the Company, filed a lawsuit in the Federal District Court for the Southern District of New York (Lawsuit). Gener SA is co-venturer

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with Coastal Itabo, Ltd. (Coastal) in Empressa Generadora de Electricidad Itabo, S.A. (Itabo), a Dominican Republic electric generation Company. The lawsuit sought to enjoin the efforts initiated by Coastal to hire an alleged independent expert, purportedly pursuant to the Shareholder Agreement between the parties, to perform a valuation of Gener SA s aggregate interests in Itabo. Coastal asserts that Gener SA has committed a material breach under the parties Shareholder Agreement. Therefore, Gener is required if requested by Coastal to sell its aggregate interests in Itabo to Coastal at a price equal to 75% of the independent expert s valuation. Coastal claims a breach occurred based on alleged violations by Gener SA of purported antitrust laws of the Dominican Republic. Gener SA disputes that any default has occurred. On March 11, 2004, upon motion by Gener SA, the court in the Lawsuit enjoined the evaluation being performed by the expert and ordered the parties to arbitration. On March 11, 2004, Gener SA commenced arbitration proceedings. The arbitration is ongoing.

Pursuant to the pesification established by the Public Emergency Law and related decrees in Argentina, since the beginning of 2002, the Company s subsidiary TermoAndes has converted its obligations under its gas supply and gas transportation contracts into pesos. In accordance with the Argentine regulations, payments must be made in Argentine pesos at a 1:1 exchange rate. Some gas suppliers (Tecpetrol, Mobil and Compañía General de Combustibles S.A.) have objected to the payment in pesos. On January 30, 2004, such gas suppliers presented a demand for arbitration at the ICC (International Chamber of Commerce) requesting the re-dollarization of the gas price. TermoAndes replied on March 10, 2004 with a counter-lawsuit related to (i) the default of suppliers regarding the most favored nation clause, (ii) the unilateral modification of the point of gas injection by the suppliers, (iii) the obligations to supply the contracted quantities and (iv) the ability of TermoAndes to resell the gas not consumed. On May 12, 2004, the plaintiffs responded to TermoAndes counterclaim. In October 2004, the case was submitted to a court of arbitration for determination of the Terms of Reference. The arbitration seeks approximately $10 million for past gas supplies. The parties are in the process of submitting evidence to the arbitrator.

On or about October 27, 2004, AES Red Oak LLC (Red Oak) was named as a defendant in a lawsuit filed by Raytheon Company (Raytheon) 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 concerning alleged issues related to the construction and/or performance of the Red Oak project. The complaint seeks the return from Red Oak of approximately $30 million that was drawn by Red Oak under a letter of credit that was posted by Raytheon related to the construction and/or performance of the Red Oak project. Raytheon also seeks $110 million in purported additional expense 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 counterclaims against Raytheon. In January 2005, Raytheon moved for dismissal of Red Oak s counterclaims. In March 2005, the motion to dismiss was withdrawn and a partial motion for summary judgment was filed by Raytheon. Red Oak expects to defend itself vigorously in the action.

On or about January 26, 2005, the City of Redondo Beach, California, provided AES Redondo Beach LLC (Redondo Beach), a subsidiary of the Company, a notice of assessment for utility user s tax (UUT) for the period of May 1998 through September 2004. The assessment includes alleged amounts owing of $32.8 million for gas usage and $38.9 million for interest and penalties. Redondo Beach has objected to the assessment and an administrative hearing is currently scheduled before the City s Tax Administrator for March 29, 2005.

On April 26, 2003 approximately 4,000 gallons of oil spilled as a result of incorrect loading and storage tank value settings at the Company s gas turbine plant at Condado del Rey, Panama. Remediation efforts were promptly conducted and completed. AES Panama also agreed with Autoridad Nacional del Ambiente (ANAM), the Panamaninan National Environmental Authority, to improve auditing and environmental management plans at the plant. In addition, AES Panama is in discussions with ANAM to improve adjacent watershed conditions. As part of these recent discussions and in response to a letter received by AES Panama the business agreed to pay a fine of $250,000. The Company does not expect that the anticipated fine or the costs to institute new auditing and management plans or efforts to improve watershed conditions will be material to our operations or results.

In May 2000, the New York State Department of Environmental Conservation (NYSDEC) issued a Notice of Violation (an NOV) to New York State Electric and Gas (NYSEG) for violations of the Federal Clean Air Act and the New York Environmental Conservation Law at the Greenidge and Westover plants, related to NYSEG s alleged failure to undergo an air permitting review prior to making repairs and improvements during the 1980s and 1990s. Subsequent to the original NOV, the State of New York added two additional NYSEG plants, Jennison and Hickling, to the enforcement action. Pursuant to the agreement relating to the acquisition of the plants from NYSEG, AES Eastern Energy (AEE) agreed with NYSEG that AEE would assume responsibility for the NOV, subject to a reservation of AEE s right to assert any applicable exception to its contractual undertaking to assume pre-existing environmental liabilities. On January 11, 2005, the State of New York announced that it and AEE had executed a Consent Decree settling all environmental noncompliance issues alleged by the NOV for the Greenidge, Westover, Jennison, and Hickling plants. Under the Consent Decree, AEE has agreed to pay a $0.7 million civil penalty for the violations assessed to NYSEG and will deposit $1 million in an AES Environmental Mitigation Project Account that will be used to carry out one or more projects pertaining to energy efficiency, renewable energy and/or clean air projects that are approved by the NYSDEC and the Office of the Attorney General. In addition, AEE has agreed to install emission control equipment, the total cost of which is estimated to be $44 million. AEE has projected that its share of the capital costs to install the MCP Project at Greenidge Unit 4 will be approximately $30 million.

The Company is also 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, 2004.

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 2004.

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 following tables set forth the high and low sale prices for our common stock as reported by the NYSE for the periods indicated.

Price Range of Common Stock

2004	**High**	**Low**
First Quarter	$ 10.71	$ 8.02
Second Quarter	10.15	7.69
Third Quarter	10.65	9.20
Fourth Quarter	13.67	10.15

2003	**High**	**Low**
First Quarter	$ 4.04	$ 2.72
Second Quarter	8.37	3.75
Third Quarter	7.70	5.91
Fourth Quarter	9.50	7.57

Holders

As of March 3, 2005, there were 10,270 record holders of our common stock, par value $0.01 per share.

Dividends

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 senior subordinated notes and 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/A for information regarding Securities Authorized for Issuance under Equity Compensation Plans.

ITEM 6. *SELECTED FINANCIAL DATA*

The selected financial data set forth in this Item 6 has been restated to correct errors that were contained in our consolidated financial statements and other financial information included in our Annual Report on Form 10-K for the year ended December 31, 2004, filed with the U.S. Securities and Exchange Commission on March 30, 2005. The following selected financial data should be read in conjunction with our restated consolidated financial statements and the related notes to the consolidated financial statements.

Our 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/A for further explanation of the effect of such activities. Please refer to Item 7 and Note 22 to the Consolidated Financial Statements included in Item 8 of this Form 10-K/A 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.

	Years Ended December 31, 2004 (Restated)(1)	2003 (Restated)(1)	2002 (Restated)(1)	2001 (Restated)(2)	2000 (Restated)(2)
	(in millions, except per share data)				
Statement of Operations Data:					
Revenues	$ 9,463	$ 8,413	$ 7,377	$ 6,299	$ 4,958
Income (loss) from continuing operations	258	311	(2,064)	323	605
Discontinued operations, net of tax	34	(787)	(1,561)	(130)	68
Cumulative effect of change in accounting principle, net of tax		41	(376)		
Net income (loss)	$ 292	$ (435)	$ (4,001)	$ 193	$ 673
Basic income (loss) earnings per share:					
Income (loss) from continuing operations	$ 0.40	$ 0.52	$ (3.83)	$ 0.61	$ 1.37
Discontinued operations	0.06	(1.32)	(2.89)	(0.25)	0.15
Cumulative effect of change in accounting principle		0.07	(0.70)		
Basic income (loss) earnings per share	$ 0.46	$ (0.73)	$ (7.42)	$ 0.36	$ 1.52
Diluted income (loss) earnings per share:					
Income (loss) from continuing operations	$ 0.40	$ 0.52	$ (3.83)	$ 0.60	$ 1.28
Discontinued operations	0.05	(1.32)	(2.89)	(0.24)	0.14
Cumulative effect of change in accounting principle		0.07	(0.70)		
Diluted income (loss) earnings per share	$ 0.45	$ (0.73)	$ (7.42)	$ 0.36	$ 1.42

	December 31, 2004 (Restated)(1)	2003 (Restated)(1)	2002 (Restated)(1)	2001 (Restated)(2)	2000 (Restated)(3)
	(in millions)				
Balance Sheet Data:					
Total assets	$ 28,923	$ 29,137	$ 34,550	$ 36,636	$ 32,476
Non-recourse debt (long-term)	11,817	10,930	10,044	10,787	9,306
Non-recourse debt (long-term) Discontinued operations		56	4,126	4,037	3,557
Recourse debt (long-term)	5,010	5,862	6,755	5,891	4,686
Stockholders equity (deficit)	972	(68)	(855)	5,154	5,261

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

(2) See Note 1 to the Consolidated Financial Statements for the nature of the errors in 2001 and 2000.

(3) The cumulative effect of the errors, as described in Note 1 to the Consolidated Financial Statements was a reduction to stockholders equity of $172 million at December 31, 1999.

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 our consolidated financial statements and other financial information for the years ended December 31, 2004, 2003 and 2002 as discussed below and in Note 1 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 to the consolidated financial statements.

RESTATEMENT OF CONSOLIDATED FINANCIAL STATEMENTS

Background

In our previously filed Form 10-K, for the year ended December 31, 2004, management reported that a material weakness existed in our internal controls over financial reporting related to accounting for income taxes. Specifically, the Company lacked effective controls for the proper reconciliation of the components of its foreign subsidiaries income tax assets and liabilities to related consolidated balance sheet accounts.

The Company s initial remediation plan included the following actions:

- adopt a more rigorous approach to communicate, document and reconcile the detailed components of subsidiary income tax assets and liabilities, and to more fully integrate the income tax accounting process with the financial reporting process;

- expand the resources in the income tax accounting function and provide additional training to the Company s foreign subsidiaries; and

- conduct a comprehensive evaluation of the Company s current income tax accounting and reporting processes, to identify and implement additional best practice solutions regarding efficient data collection, integration and controls.

Given the complex nature of the foreign subsidiary income tax reconciliation process, the previous lack of comprehensive U.S. GAAP income tax accounting expertise within certain of the Company s foreign businesses and the number of locations to be reviewed, the Company engaged an international public accounting firm to assist in the reconciliation and evaluation process.

After examining certain historical purchase transactions from 1999 2002 and reviewing the reconciliations of detailed historical income tax return records to reported book/income tax differences, various accounting errors were identified. As a result of these intial findings, on July 27, 2005 the Company announced that it would restate its previously filed financial statements. At the same time, management also expanded the scope of the review to include the composition of other material current and deferred income tax related balances including those recorded by or, on behalf of, our domestic subsidiaries and the parent company. As a result of this expanded review, additional non-tax items also were identified and corrected.

Throughout this restatement review process, management with the support of the Audit Committee and the Board of Directors of AES, committed significant internal and external resources to ensure that we properly identified and resolved outstanding issues, even though this caused a delay in the filing of our June 30, 2005 and September 30, 2005 quarterly financial statements. The most significant adjustments recorded as part of the restatement involved complex areas of accounting and in certain cases, required a significant degree of judgement associated with U.S. GAAP and its technical interpretation relative to foreign income tax rules and regulations. Our findings throughout this process continue to support our initial conclusion that all errors identified were inadvertent and unintentional.

Our business structure has historically been decentralized and currently encompasses over 27 countries, many with unique local statutory reporting requirements and different degrees of expertise within AES internally and through locally accessible accounting and tax organizations. We have recognized the complexity of our business and have taken many steps to improve corporate involvement and oversight through increased commitment to improving our people, processes and financial systems. In conjunction with the Board of Directors, restructuring efforts towards this end began in 2002 and continued with our corporate preparation and readiness to be in compliance with the requirements of Sarbanes-Oxley. We have continued to hire additional accounting, financial reporting, income tax, internal control, internal audit and compliance staff and have created several new senior corporate leadership positions related to these functions. The Corporate finance function is also providing more oversight to ensure that we have the appropriate accounting, tax and finance people employed at our subsidiaries. To this end, in 2005, we hired new chief financial officers for our utility and generation companies in Brazil and at our utility company in Cameroon, two of our most complex businesses. Additional processes and controls have been initiated regarding the communication and documentation of the accounting and deferred income tax consequences of transactions. The Company implemented a new consolidation system in early 2004 which increased the consistency and dependability of the data collection process, and we also have begun to evaluate the implementation of enterprise-wide systems solutions to further improve the quality and integration of our financial and operational systems across our businesses. We recognize that additional steps need to be taken to continue to strengthen the effectiveness of our controls and are committed to further improve our processes and systems and to leverage the capabilities of our people into the future.

In the short term and as a result of our tax findings, we also reinforced our commitment to provide accurate and transparent financial information by engaging additional experienced external tax professionals to assist us in the remediation of our tax material weakness and to provide training, assistance and support as we continue to strengthen our global processes related to accounting for income taxes. For the past eight months, we have utilized the assistance of a significant number of external tax professionals together with our accounting and tax professionals from within our businesses and at corporate to ensure a rigorous review of major acquisitions and other transactions dating back more than five years in certain cases.

The following table quantifies the net impact of the restatement corrections by income statement line item for the three years ended December 31, 2004, 2003 and 2002 respectively and includes the resulting impact on diluted earnings per share from continuing operations. The major line items affected include depreciation expense, interest expense, goodwill impairment expense, gain (loss) on foreign currency translation, income tax expense and the related impacts on minority interest calculations.

	Year Ended December 31,		
	2004	**2003**	**2002**
	($ in millions, except per share amounts)		
Income (loss) from continuing operations as previously reported	**$ 366**	**$ 332**	**$ (1,646)**
Changes in income (loss) from continuing operations from restatement due to:			
Increase in gross margin	$ 10	$ 23	$ 18
(Increase) in interest expense	$ (31)	$	$ (48)
(Increase) in goodwill impairment expense	$	$	$ (97)
(Increase) in foreign currency transaction losses	$ (29)	$ (31)	$ (185)
(Increase) in income tax expense	$ (126)	$ (7)	$ (168)
Decrease (increase) in minority interest and other	$ 68	$ (6)	$ 62
	$ (108)	**$ (21)**	**$ (418)**
Income (loss) from continuing operations as restated	**$ 258**	**$ 311**	**$ (2,064)**
Diluted earnings (loss) per share from continuing operations as previously reported	**$ 0.57**	**$ 0.56**	**$ (3.06)**
Changes due to restatement effects	(0.17)	(0.04)	(0.77)
Diluted earnings (loss) per share from continuing operations as restated	**$ 0.40**	**$ 0.52**	**$ (3.83)**
Diluted shares outstanding	648.1	598.3	538.9

The Company has concluded that the reasons for these errors primarily related to the lack of sufficient internal resources with comprehensive U.S. GAAP knowledge pertaining to the computation of complex deferred income tax impacts arising from foreign acquisitions and restructurings. Secondly, the Company lacked adequate procedures for the reconciliation between income tax returns to financial statement balance sheet accounts. This lack of adequate procedures allowed income tax journal entries to be recorded in consolidation but not subsequently provided to our subsidiary companies for recording, updating and proper translation from local currency to U.S. dollars.

Income Tax Adjustments

The errors identified from the income tax review can be categorized into three types of deferred tax issues. Details regarding material findings associated with each issue are provided below:

1. Deferred income tax adjustments associated with foreign acquisitions and restructurings

La Electricidad de Caracas (EDC)

The most significant deferred income tax restatement adjustment related to the purchase of a majority interest in EDC, a private integrated utility in Venezuela in June, 2000. At that time, a deferred income tax liability was recorded representing the difference between the non-inflation indexed income tax basis and the resulting adjusted purchase basis (assigned carrying value) of fixed assets. However, Venezuelan income tax provisions allow for the indexing of EDC s non-monetary assets and equity, as a result of inflation. This indexing created an additional layer of tax basis that should have been included as part of the acquisition income tax basis at the time of the acquisition.

The impact of correcting the income tax basis used to calculate the original temporary difference was an increase of $668 million in the original deferred income tax asset. In addition, several other purchase accounting adjustments were recorded to correctly account for the treatment of deferred charges and the fair value applied to an equity investment held by EDC at the time of acquisition. The recording of the deferred income tax asset related to indexation and the other noted adjustments affected the allocation of the excess fair value over cost (commonly referred to as negative goodwill) to non-monetary assets.

The net result of these adjustments decreased fixed assets in 2000 by $572 million and decreased other assets by $85 million. The reduction in depreciation and amortization expense was $24 million for the year ended December 31, 2002, $24 million for the year ended December 31, 2003 and $23 million for the year ended December 31, 2004.

Eletropaulo Metropolitana Electricidade de Sao Paulo S.A. (Eletropaulo)

At the time of the acquisition of Eletropaulo, a regulated utility located in Brazil, the Company did not record certain deferred income taxes on the difference between the tax basis of land and the related book basis which was adjusted to fair value under acquisition accounting guidelines. The correction of this error resulted in the recording of additional deferred income tax liabilities of $101 million at the initial date of consolidation in February 2002. This increase in deferred income tax liability increased the original goodwill calculated as the excess purchase price over the fair value of assets and liabilities. As a further result, this adjustment also increased goodwill impairment expense subsequently recognized in 2002 by $71 million.

Brasiliana Energia, S.A. (Brasiliana)

In January, 2004 the Company entered into a debt restructuring transaction with the Brazilian National Bank for Economic and Social Development (BNDES), whereby BNDES received a 54% economic interest in our Brazil distribution business and two generating facilities in exchange for the cancellation of $863 million of debt and accrued interest owed by AES Elpa and AES Transgas, holding companies for the Brazilian operations. After the Company made a cash payment of $90 million, the remaining indebtedness of $510 million was re-profiled at a 9% stated interest rate with extended maturities. This exchange was accounted for as a modification of debt. The terms of the agreement state that penalty interest as of December 31, 2004 of $194 million would be cancelled in the future ratably as the principal of the new $510 million debentures are paid within the stated timeframes. This treatment gave rise to a deferred income tax liability. As a result of the income tax review, it was determined that a deferred income tax liability should have been recorded for $194 million of penalty interest anticipated to be forgiven in the future. To correct this error, the additional deferred income tax liability was recorded as part of the stock issued for debt restructuring transaction, with the following impacts:

- A deferred income tax liability of $73 million at Brasiliana (the new parent company of the restructured entities) was recorded as of January, 2004. This deferred liability is also subject to foreign currency remeasurement in each subsequent reporting period.

- Debt modification calculations were adjusted to include the fair value of the increased income tax expense due to the forgiveness of debt compared to the book value of debt remaining. The resulting impact reduced the debt discount from $26 million to $20 million and decreased the effective interest rate from the originally calculated amount of 9.67% to 9.32%. This adjustment did not change our conclusion regarding the accounting treatment of the transaction as a modification of debt.

These adjustments also impacted the amounts recorded to reflect the BNDES debt restructuring described above. This impact is described below in the Other Non Income Tax Adjustments section.

Other Acquisition Related Income Tax Adjustments

As a result of the comprehensive review of income tax accounting, certain other adjustments were made to correct errors identified at other subsidiaries, primarily related to recording of deferred income taxes arising from the step up of acquired assets to fair value and/or from other purchase accounting items. These adjustments increased or decreased fixed assets or concession assets and as a result impacted depreciation or amortization charges recorded within the Company s statements of operations. The impact on depreciation expense from these adjustments was an increase of $3 million for the year ended December 31, 2002, an increase of $3 million for the year ended December 31, 2003 and a decrease of $5 million for the year ended December 31, 2004. The impact on amortization expense was a decrease of $1 million for the year ended December 31, 2002, a decrease of $1 million for the year ended December 31, 2003 and a decrease of $5 million for the year ended December 31, 2004.

2. Foreign currency remeasurement of deferred income tax balances where the U.S. dollar is the functional currency at certain subsidiaries

The functional currency for certain of the Company s foreign subsidiaries is the U.S. dollar. After reviewing the income tax balances for certain of the Company s U.S. dollar entities in Venezuela, Brazil, Chile, Colombia, Dominican Republic, Argentina and Mexico, the Company discovered that deferred income taxes were remeasured from local currency to the U.S. dollar using the historical exchange rate versus the current exchange rate as prescribed by Statement of Financial Accounting Standard (SFAS) No. 52, Foreign Currency Translation and SFAS No. 109, Accounting for Income Taxes, starting in the year of acquisition or formation. In addition, as noted above, certain additional deferred tax amounts were recorded in these entities, which also required remeasurement the largest of which was the additional deferred tax asset related to the EDC purchase accounting indexation adjustment of $668 million described above.

The additional foreign currency transaction losses related to deferred taxes was $187 million for the year ended December 31, 2002, $34 million for the year ended December 31, 2003 and $38 million for the year ended December 31, 2004.

3. Reconciliation of income tax returns to U.S. GAAP income tax balances

The remediation plan involved a detailed review of current and temporary differences identified through an analysis of local income tax return filings. The completion of this review also required the Company to fully evaluate adjustments which had been previously recorded in consolidation, but which should have been recorded at a subsidiary level where the appropriate analysis of the tax jurisdiction could be made. This process led to the identification of errors that accounted for additional income tax expense, the major components of which are described below:

Establishment of Deferred Tax Liability for Brazilian Unrealized Foreign Currency Gains

Certain of the Company s Brazilian subsidiaries have designated the U.S. dollar as the functional currency for accounting purposes. For Brazilian tax purposes, these companies have elected to treat these exchange gains or losses as taxable or deductible only when cash payments are made. The Company did not record deferred assets or liabilities related to the unrealized gains and losses that occur on an interim basis related to its U.S. dollar denominated debt. Under U.S. GAAP, these increases/decreases in deferred liabilities/assets are permanent differences that are recorded as an adjustment to tax expense. The impact of recording these changes in deferred taxes increased income tax expense by approximately $32 million in 2004 and $4 million in 2003.

Establishment of a U.S. Liability Related to Brazilian Deferred Tax Assets

One of the Company s Brazilian subsidiaries, Sul, which has designated its functional currency as the Brazilian real, has generated deferred tax assets mainly related to net operating losses, unrealized tax losses on foreign currency transactions and certain other taxable temporary differences. A restructuring transaction was undertaken in relation to this subsidiary in July 2002. At the time of this restructuring, the Company should have recorded a reduction to the deferred tax assets for the U.S. income tax liability associated with the future projected Brazilian taxable income. This reduction, along with other deferred tax impacts related to Sul being part of the Company s consolidated tax group resulted in additional tax expense of $32 million in 2004, $28 million in 2003 and $66 million in 2002.

Establishment of Other Valuation Allowances

The Company determined that certain valuation allowances should have been provided at various subsidiaries in Chile, Colombia, Brazil and Argentina related to deferred tax assets recorded primarily related to net operating loss carryforwards. Under U.S. GAAP, the Company is required to assess its ability to utilize deferred tax assets under a more likely than not standard and provide a valuation allowance to the extent the asset or any part of it does not meet this test. As part of the deferred tax review, the Company determined that these deferred tax assets were unlikely to be utilized in full or in part, based on information available in these historical periods and consequently did not meet the more likely than not standard. As a result, the Company recorded valuation allowances which resulted in additional tax expense of $18 million in 2004, a reduction of tax expense of $38 million in 2003 and additional tax expense of $79 million in 2002.

Other Tax Expense Items

The Company undertook a detailed comparison of the tax returns filed to accounting records in a majority of the countries in which we operate and identified certain other adjustments related to this reconciliation. Most significantly, these adjustments included the following:

- non-deductibility of certain holding company interest and goodwill;
- capitalized interest on tax holiday projects;
- treatment of certain foreign investment tax credits;
- reconciliation of other deferred tax balances; and
- changes in pre-tax book income related to other non-tax restatement adjustments.

The net impact of these other tax expense items resulted in additional tax expense of $23 million in 2002, $13 million in 2003 and $44 million in 2004. The cumulative impact on income tax expense, as a result of the restatement adjustments, was an increase of $168 million for the year ended December 31, 2002, an increase of $7 million for the year ended December 31, 2003 and an increase of $126 million for the year ended December 31, 2004.

Other Non-Income Tax Adjustments

Other non-income tax accounting errors were also identified as part of the Company s review of certain other historical transactions. The Company has concluded that the reasons for these errors primarily related to the lack of sufficient control and documentation procedures in 2002 and prior years related to certain consolidation and foreign currency translation processes. Significant non-income tax errors are described below:

AES SONEL

AES acquired 56% of SONEL located in Cameroon in July, 2001. Since that time, AES SONEL experienced a high degree of turnover of its senior accounting personnel. SONEL s accounting systems required a significant degree of manual intervention including the conversion of local GAAP financial statements into U.S. GAAP.

During the Company s 2004 year-end process, the Company discovered errors in minority interest calculations that were corrected in the Company s restated financial statements as of and for the years ended December 31, 2003 and 2002 as filed with the Securities and Exchange Commission on Form 10-K

on March 30, 2005. Subsequently, as part of the Corporate process to ensure the correct communication and documentation of the correction of the initial error at the subsidiary level, a comprehensive additional review of the preparation of the U.S. GAAP financial statements was performed and the following errors were identified:

- translation errors from local currency to U.S. dollar financial statements;
- the omission of certain purchase accounting adjustments related to the final valuation of our concession assets and recording of severance provision from the U.S. GAAP financial statements; and
- incorrect treatment related to the accounting for dividends.

The net impact of the adjustments as of December 31, 2004 resulted primarily in a reduction of intangible assets of $39 million and an increase in accumulated other comprehensive loss related to foreign currency translation of $39 million.

AES Elpa

As a result of the income tax review performed at AES Elpa, one of the Company s Brazilian holding companies, the Company identified a long-term liability which had been recorded for Brazilian GAAP but which had been omitted from U.S. GAAP financial statements at the acquisition date. The proper recording of this liability at the acquisition date would have increased the opening balance of goodwill, which was subsequently impaired and thereby written off as of the end of December, 2002. The impact of this adjustment as of December 31, 2002, increased long term liabilities by $34 million and increased goodwill impairment expense and prior retained earnings by the same combined amount. This long-term liability is accreted by an interest expense component on a monthly basis. The increase in interest expense was $5 million for the year ended December 31, 2002, $6 million for the year ended December 31, 2003 and $5 million for the year ended December 31, 2004.

AES Tiete

The Company determined that an error had been made in the initial accounting for a debt instrument which had been assumed at the date of purchase of Tiete, a generation company in Brazil in 1999. The debt requires an annual adjustment to principal based on changes in the local rate of inflation. The Company accounted for this by using estimates of future inflation over the life of the debt and amortizing these adjustments as a component of interest expense over the term of the loan. These future inflation estimates were recorded on the balance sheet as a deferred financing cost within long-term assets. Periodically, adjustments were made to these estimates when the actual annual inflation calculations were charged to the principal balance. Subsequently, it was determined that inflation changes should be calculated and adjusted on a monthly basis through interest expense based on the rate of inflation in that month, regardless of how the actual cash payment would finally be determined. The impact on interest expense was an increase of $41 million for the year ended December 31, 2002, a decrease of $7 million for the year ended December 31, 2003 and an increase of $28 million for the year ended December 31, 2004. The long term asset account was corrected to remove the estimated inflation component and resulted in a decrease in assets of $6 million as of December 31, 2002, a decrease of $21 million as of December 31, 2003 and a decrease of $42 million as of December 31, 2004.

SUL and Eletropaulo

The Company determined that an error had been made regarding the timing of the recognition of certain revenues recorded by its Brazilian utilities Eletropaulo and Sul. The tariff rates, as set by the Brazilian regulatory authority (ANEEL) provide that a percentage of a distributor s revenue is added to the consumer tariff rate in return for the Company s future spending of these amounts on capital or operating expense projects approved by ANEEL for the express purpose of improving the efficiency of the electrical system. Eletropaulo and Sul had previously recognized the revenue related to this portion of the tariff when billed, and recorded the future operating expense and capital project expenditures when incurred, since the expenditures were not considered pass through costs for purpose of a future tariff reset. However, under the guidance of SFAS 71 Accounting for the Effects of Certain Types of Regulation , Eletropaulo and Sul should have deferred this portion of revenue until such time that the related expenditures were incurred. The correction of this error resulted in a decrease in revenues of $11 million, $8 million and $8 million for the years ended December 31, 2004, 2003 and 2002, respectively. The proper recording of this liability as of the date of acquisition of Eletropaulo would have also increased the opening balance of goodwill, which was subsequently impaired and written off in December, 2002. The correction of this error, therefore, also increased goodwill impairment expense by $6 million in 2002.

Brasiliana Energia

The correction of the error related to AES Elpa described above and other adjustments prior to January 2004 which impacted the net assets of Eletropaulo, Tiete and Uruguaiana, also impacted the recording of the Brazilian debt restructuring transaction with our lender, BNDES, as described earlier. The impact on the 2004 restated financials decreased the minority interest share allocated to BNDES by $79 million and increased additional paid-in capital, a component of stockholders equity, by $79 million. The adjustment to additional paid-in capital was recorded in accordance with the Company s previously established accounting policy pertaining to gains or losses resulting from subsidiary sales of stock as permitted under SEC Staff Accounting Bulletin No. 51, Accounting for Sales of Stock by a Subsidiary.

Corporate Consolidation Accounting

During the restatement period, the Company undertook additional reviews of the consolidation process, including a review of consolidation journal entries to ascertain that appropriate supporting documentation existed and that current personnel who were performing the consolidation understood the basis for these entries. Several historical consolidation elimination adjustments were identified as errors which primarily affected deferred income taxes and other accumulated comprehensive income balances. The errors originated in years prior to 2002 and generally resulted from an inadequately controlled consolidation process including the elimination of investment accounts against subsidiary equity balances, general balancing controls related to the income statements and balance sheets submitted by our subsidiaries, and inadequate balance sheet reconciliations of consolidated deferred income tax accounts. The correcting entries resulted primarily in a decrease in deferred income tax liabilities and an increase in foreign currency translation, a component of other comprehensive income, of $294 million.

Cash Classifications

As part of an ongoing balance sheet review process, it came to the Company s attention that several of its subsidiaries incorrectly included certain short-term investments as cash and cash equivalents in the balance sheet. The restatement impact was a decrease in cash and cash equivalents and an increase in short-term investments of $127 million and $74 million as of December 31, 2004 and 2003, respectively.

Cash Flow Reclassification

The Company includes components of the cash flows for its discontinued operations within the Consolidated Statements of Cash Flows (Cash Flow Statement) in operating, investing and financing activities. A separate line entitled Decrease in cash and cash equivalents of discontinued operations and businesses held for sale was previously presented on the face of Cash Flow Statement to reconcile back to the Company s cash balance on the face of the Consolidated Balance Sheets, which excludes cash from discontinued operations. As part of the restatement, the Company has changed its presentation to include the net change in cash balances for discontinued operations as a component of net cash from operating activities. The result of this reclassification increased net cash from operating activities by $4 million, $66 million and $85 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Other Immaterial Errors

Certain other immaterial errors were identified and corrected in the appropriate periods.

Prior Restatement of 2002 and 2003 Annual Financial Statements

Included in the 2004 Annual Report on Form 10-K as filed with the U.S. Securities and Exchange Commission on March 30, 2005, the Company restated its 2002 and 2003 consolidated financial statements. The errors relate to the following areas:

Deferred taxes

During the Company s 2004 year end closing process, we discovered certain accounting errors under U.S. GAAP related to the recording of deferred taxes associated with Eletropaulo, one of our Brazilian subsidiaries. The reconciliation of income tax accounts with Eletropaulo led to a more comprehensive reconciliation of our consolidated income tax balances with certain of our other foreign subsidiaries. As a result of this process we discovered additional discrepancies between the components of the deferred tax balances computed by certain foreign subsidiaries and those maintained by the Company on a consolidated basis. As a result of this review process, the Company recorded $17 million and $18 million of additional deferred tax expense in 2001 and 2000, respectively, as an adjustment to accumulated deficit as of January 1, 2002, $8 million additional deferred tax expense in 2002 and $9 million in 2003. In addition, certain income tax amounts were reclassified between current tax payable, deferred tax payable and minority interest.

Additionally, we identified an error in the original entry to record deferred taxes related to the minimum pension liability recorded by Eletropaulo and reflected in the Company s 2002 balance sheet at the time we obtained a controlling interest in that entity and began to consolidate Eletropaulo s financial statements. To correct this error we recorded a $7 million decrease in the pension liability, a $36 million decrease in accumulated other comprehensive loss and a $29 million increase in goodwill impairment expense. The adjustments would have originally been recorded against Eletropaulo s opening goodwill balance. However, goodwill was written off at the end of 2002 as a result of impairment of Eletropaulo s goodwill.

Minority interest

During the Company s 2004 year end closing process, we discovered an error in the conversion of the minority interest payable to U.S. dollars related to two of our investments Eletropaulo and AES SONEL, our Cameroonian utility subsidiary. The impact of the restatement adjustment is as follows:

- Increase in minority interest payable by $7 million in 2002 and $69 million in 2003
- Increase in accumulated other comprehensive loss by $7 million in 2002 and $69 million in 2003

Discontinued operations

As part of the year end closing process, it was discovered that the Company had not written off certain liabilities and the remaining portions of changes in derivative fair value a component of accumulated other comprehensive loss related to hedge positions, for certain businesses classified as discontinued operations. After analyzing the appropriate timing of these transactions, it was determined that these amounts should have been recorded when the related business was impaired.

The impact of these restatement adjustments resulted in an increase in net loss from operations of discontinued businesses of $13 million in 2002 and $7 million in 2003.

Executive Summary and Overview

The following discussion should be read in conjunction with the Consolidated Financial Statements and applicable Notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K/A, and other information included in this report.

Who Are We?

AES is a global power company managed to meet the growing demand for electricity in ways that benefit all of our stakeholders. AES is a holding company that through its subsidiaries and affiliates owns and operates a portfolio of electricity generation and distribution businesses in 27 countries. We seek to capture the benefits of our global expertise and economies of scale in our operations. Predictable cash flow, an efficient capital structure and world-class operating performance are the focus of our management efforts.

What Business Are We In?

We operate two principal businesses. The first is the generation of power for sale to utilities and other wholesale customers. The second is the operation of utilities which distribute power to retail, commercial, industrial and governmental customers. Each principal business generates approximately one half of the Company s revenues. Our financial results are reported as four business segments on a regulated and non-regulated basis by region, which further refines our core business structure:

Generation

- Contract Generation
- Competitive Supply

The generation business segments earnings and cash flows may be significantly affected by: (1) the reliability of generating capacity at our existing facilities, (2) newly-completed projects or acquisitions of generating facilities, (3) demand for power beyond minimum requirements under the contract generation segment power sales agreements, or the demand for power as affected by weather conditions in our competitive supply segment, (4) prices for power and fuel supply requirements, (5) the credit quality of the counterparties to our power sales agreements, (6) changes in our cost structure, including cost associated with operation, maintenance and repair, transmission access, insurance and environmental compliance, including expenditures relating to environmental emission equipment or environmental remediation, (7) changes in laws or regulations, and (8) changes in the foreign currency exchange rates for certain of our facilities outside the United States.

Our contract generation and competitive supply segments consist of approximately 37 gigawatts of generating capacity from 99 power plants in 23 countries. Our contract generation plants have contractually limited their exposure to electricity price volatility by entering into power sales agreements of five years or longer for 75% or more of their output capacity. Exposure to fuel supply risks is also limited through long-term fuel supply contracts or through fuel tolling arrangements. Through these contractual agreements, the businesses generally reduce commodity and electricity price volatility and thereby increase the predictability of their cash flows and earnings.

Our competitive supply segment consists primarily of power plants selling electricity to wholesale customers through competitive markets and, as a result, the cash flows and earnings of such businesses are more sensitive to fluctuations in the market price of natural gas, coal and other fuels. However, for our U.S. competitive supply business which includes a fleet of low-cost coal fired plants in New York, we typically hedge the majority of our fuel exposure on a rolling two year basis.

Utilities

- Large Utilities
- Growth Distribution

The utility business segments earnings and cash flows may be significantly affected by: (1) changes in economic conditions and policies, (2) demand for power, including demand variability associated with weather conditions, (3) prices for power and fuel supply requirements, (4) the extent of commercial losses, which include fraudulent activity by our customers, (5) changes in our cost structure, including costs associated with operation, maintenance and repair, insurance and environmental compliance, including expenditures relating to environmental emissions or environmental remediation, (6) changes in laws or regulation, including changes in electricity tariff rates and our ability to obtain tariff adjustments for increased expenses, and (7) changes in foreign currency exchange rates, particularly in Brazil and Venezuela.

These combined businesses consist of 15 distribution companies in eight countries with over 11.2 million end-user customers. The large utilities segment includes three large utilities located in the U.S. (IPL), Brazil (Eletropaulo) and Venezuela (EDC) all of which maintain a monopoly franchise within a defined service area. The challenge within these businesses includes providing dependable and quality service to a large base of customers, and effectively being able to achieve appropriate returns through tariff increases. While we are exposed to currency, political and economic risks within developing countries, we also have excellent growth opportunities given increasing demand in these markets.

Our growth distribution segment is comprised of our interests in electricity distribution facilities located in developing countries where the demand for electricity is expected to grow at a higher rate than in more developed parts of the world. However, these businesses often face particular challenges associated with their presence in developing countries such as outdated equipment, significant electricity theft-related losses, cultural problems associated with customer safety and non-payment, emerging economies, and potentially less stable governments or regulatory regimes.

What Was Our Key Focus For 2004?

In 2004, we focused on strengthening our balance sheet, improving the operations of our existing portfolio of assets and pursuing disciplined growth. We strengthened our balance sheet by paying down parent level debt, extending the average maturity of our parent debt and restructuring the debt of several key subsidiaries. In our operating businesses, we focused on improving the strategic sourcing of critical supplies and services, obtaining tariff increases and favorable regulatory treatment of new investments, reducing the impact of forced outages on our generation plants and reducing the impact of commercial losses on our utilities and distribution businesses. 2004 was an important transition year for us as we completed several years of restructuring efforts. It was also a year of strong financial performance with solid improvements in revenue and gross margin, both building the foundation for long-term growth.

Operating Highlights

	2004	2003	2002
Revenue	$ 9,463	$ 8,413	$ 7,377
Gross Margin	$ 2,782	$ 2,459	$ 1,968
Gross Margin as a % of Revenue	29.4 %	29.2 %	26.7 %
Net Cash Provided By Operating Activities	$ 1,571	$ 1,642	$ 1,535
Diluted Earnings (Loss) Per Share from Continuing Operations	$ 0.40	$ 0.52	$ (3.83)

Revenue We achieved revenues in 2004 of $9.5 billion, an increase of 12% from $8.4 billion in the prior year largely reflecting increased pricing due to successful pass through of tariff increases in our large utilities and the impact of several new projects coming on line within our generation business.

Gross margin Gross margin increased 13% over 2003 to $2.8 billion with higher contributions from all four of our segments. In addition, gross margin as a percent of sales increased to 29.4% versus 29.2% in the prior year.

Earnings per share Diluted earnings per share from continuing operations decreased from $0.52 in 2003 to $0.40 in 2004. Although our key operating measures improved substantially year over year, the company was negatively impacted by foreign currency transaction losses related to subsidiary debt denominated in U.S. dollars, higher income tax expense and higher minority interest related to our Brazil restructuring.

Operating cash flow We generated $1.6 billion of net cash from operating activities which was $71 million lower than 2003. This year over year decline was largely driven by a return to normalcy in our Brazilian utility business which had dramatically extended its vendor payments in 2003 while going through the debt restructuring process. Days payables outstanding in this business were at 72 at the end of 2003 and are now at a more acceptable level of 47 as of the end of 2004.

Strategic Highlights

Strengthening Our Balance Sheet

In 2004, we continued to make progress in strengthening our financial position in a number of ways. AES reduced overall recourse debt at the parent level by approximately $800 million to approximately $5.2 billion at year end. We also continued to extend a portion of our debt repayments associated with our scheduled future debt maturities by refinancing approximately $700 million of intermediate term recourse debt at the parent level with longer term debt. These new debt obligations also bear lower interest costs than the debt refinanced. Recourse debt at the parent level with maturities of one year or less at December 31, 2004 was $142 million. We expect to either repay or refinance this debt at or prior to maturity. This debt is a junior subordinated debenture that bears a coupon rate of 4.5%. We can provide no assurance that we can refinance this debt with terms as favorable as the current debt terms.

At the subsidiary level, we refinanced or restructured more than $4.6 billion of non-recourse debt in 2004. Most of these efforts resulted in extended maturity dates and amortization schedules.

In addition, we also added approximately $1 billion of non-recourse debt at the subsidiary level. Most new debt was used to fund the construction of new electric generation plants or other capital expenditures in Indiana, Qatar, Cameroon, Hungary and Spain. Additionally, one of our subsidiaries issued approximately $120 million of debt to return a portion of our investment initially contributed to our Ebute project in Nigeria.

Liquidity (defined in the Parent Company Liquidity section in Item 7 of this Form 10-K/A as cash and equivalents plus undrawn available commitments under credit facilities) at the parent level on December 31, 2004 was $643 million. The 2004 liquidity decreased from $1 billion at the end of 2003 primarily as a result of our efforts to reduce aggregate recourse debt levels at the parent.

The aggregate amount and specific sources of cash flow relative to debt levels are important factors for the rating agencies in determining whether the Company s credit ratings should improve. Currency, political and regulatory risks tend to be the biggest variables to sustaining cash flows at predictable levels. Our large contractual and concession-based cash flow from our contract generation and large utility businesses is a mitigating factor to these variables. In 2004, more than 71% of cash distributions to the parent were from our U.S. large utility and worldwide contract generation businesses.

Restructuring Key Subsidiaries

During 2002 and 2003 we embarked upon a significant restructuring plan aimed at divesting non-core assets and raising cash to pay down debt, discontinuing underperforming businesses and restructuring significant aspects of several of our South American businesses. The latter efforts were focused on improving the businesses long-term prospects for generating acceptable returns on invested capital or extending short-term debt maturities. During 2004:

- We completed a number of debt restructuring and refinancing transactions of over $4.6 billion of non-recourse debt largely in Brazil, Chile, Venezuela, Colombia, and the US. Although these transactions have improved the financial condition of these businesses, many of these businesses are highly leveraged. As a result, these businesses may be significantly limited in their ability to meet debt service obligations or operate successfully under adverse economic conditions. However, we will continue our efforts to improve the financial condition of these businesses.

- A major part of this achievement included the restructuring of our Brazilian utility through successful negotiations with our lenders, the Brazilian National Bank for Economic and Social Development (BNDES), whereby they took a 54% economic interest in our Brazil distribution business and two generating facilities in exchange for the cancellation of $863 million of debt and accrued interest. The remaining indebtedness of $510 million was re-profiled at a 9% stated interest rate with extended maturities.

- We discontinued seven underperforming businesses and successfully concluded our negotiations to transfer or sell these operations with the final dispositions of Ede Este, Wolf Hollow and Granite Ridge in the fourth quarter of 2004.

Targeting Business Development

In 2004, we brought three power plants on line and in so doing added approximately 500 MW of capacity in three countries Qatar, Panama and Cameroon. We entered the wind generation business through our current investment in US Windforce and recent acquisition of another wind generation business SeaWest. These investments have the potential to make us a top U.S. wind developer and operator with interests in over 2,800 MW of development projects in thirteen states. We believe that wind generation will be one of the highest growth markets in Organization for Economic Co-operation and Development countries within the next five years and is a logical extension of our current contract generation business.

We also are currently involved in developing a 600 MW lignite project in Bulgaria. Although the project has a power purchase agreement with the state owned transmission company, commencement of construction is pending completion of development, receipt of appropriate regulatory approvals and financing. Commercial operation of the first 300 MW unit is expected in 2008.

Finally, we are working to develop a $750 million project to build a liquefied natural gas (LNG) terminal in Ocean Cay, Bahamas, which would include a 95-mile natural gas pipeline from the terminal to an access site in Florida, pending approvals from the Bahamian government.

Improving Operating Performance

Over the past two years we have developed key programs aimed at helping us continue to organically grow our business, provide better service to our customers, manage our costs and safeguard our people. These include the following efforts:

1. Strategic Sourcing Initiatives

In 2003 we launched a strategic sourcing initiative to avoid costs and capture cost reductions through the implementation of improved purchasing practices throughout the Company. During 2004, we evaluated and strategically sourced key spending categories including capital, services, materials and fuel. We are pursuing cost avoidance and cost reduction savings using best practice methodologies to improve our pricing through volume purchasing and product mix changes while pursuing cost reduction opportunities related to inventory management and parts rationalization. A core component of our program also includes developing supplier relationships to leverage our purchasing power and improve overall service and response times.

2. Plant Performance

In our generation businesses, we track plant reliability as a key performance indicator. For 2004, our estimated average fleet availability declined 1% from 2003 to 87%. This measure is comprised of two key elements a scheduled outage factor and a forced outage factor. The forced outage factor, which is influenced by improving operating performance through effective maintenance and operating practices, has improved nearly 25% over the last two years. In 2004, our annual forced outage factor improved from 4.6% in 2003 to 3.8% in 2004. The scheduled outage factor was nearly 2% higher in 2004 versus 2003 as the Company made strategic timing decisions concerning planned maintenance that would least impact our contractual commitments.

3. Loss Reduction

Our large non-U.S. utility businesses have embarked on comprehensive programs to track and reduce revenue losses, defined as the difference between energy purchased or generated and energy billed to customers. These losses can result from several factors including energy losses during the heat conversion process, i.e. technical losses and non-technical losses as a result of metering issues and customer theft. Progress has been made particularly in Brazil on improved metering practices, field training of inspectors, identification of commercial fraud and the establishment of a rebilling and collection process. This is a long term effort which requires both cultural and systematic process change.

What Are Our Key Challenges?

There are several challenges we face in achieving our plans for 2005 and beyond. These include the recent emergence of increased and new global competition in our markets. In the United States and Europe there has been an emergence of multiple new financial sponsors aggressively acquiring assets. Internationally, there has been a rapid increase in the number of new, regionally focused and aggressive competitors. These factors have led to more competition and an increase in the prices for assets in both secondary asset sales and privatizations.

The global power market is extremely large and offers multiple opportunities. In the European Union (EU), the market rules require a liberalized competitive wholesale power market as a condition for EU entry. However, there are a number of considerations that may limit the number of available near term opportunities in other markets. First, in the United States and, to a lesser extent, Western Europe there is limited need for new capacity, reducing the number of available Greenfield opportunities in the most stable markets. Many states in the United States have slowed or reversed their trends towards liberalization, thereby reducing the number of available opportunities. Internationally, planned privatization programs have been deferred for specific local reasons. In the markets outside the United States that are liberalizing the rules, those rules are being designed such that the risks are too great to justify the level or returns currently available. Hence we have decided to either not participate in those markets or to only do so in a limited manner and wait for a more balanced set of rules or regulations to emerge.

Political Environment

Several of our businesses operate in politically unstable environments. The impact of governmental change and uncertainty impacts foreign currency volatility (discussed below), our ability to maintain or attract needed financing as well and our ability to effectively recover costs through routine tariff or regulatory reset proceedings.

Foreign Currency Risk

A significant portion of our business portfolio is located outside of the U.S. and therefore usually subject to both currency translation and transaction risk. Our financial position and results of operations have been significantly affected in the past by significant fluctuations in the value of the Argentine peso, Brazilian real and Venezuelan bolivar relative to the U.S. dollar. We hedge certain transaction exposures principally related to debt, and have restructured debt into local currency denomination to minimize risk when possible. Although these actions may have mitigated negative impacts in certain cases, movements within currencies are difficult to predict and continue to have a significant impact on our financial results.

Regulatory Risk

Due to the regulated nature of the utilities business, we are subject to regulatory risk related to changes in tariff agreements, and existing laws and provisions. Changes in regulation may impact our future operations, cash flows and financial condition.

Long-term Contracts

Several of our power generation plants operate on a long term contract basis with one or a limited number of contracts related to both the fuel supply and power demand. The remaining periods for these long-term contracts range from 1 to 26 years. The ability of our customers and suppliers to perform under these contracts and our ability to negotiate new contracts upon expiration may have a significant impact on our results of operations in the future.

Looking Ahead What Is Our Key Focus For 2005?

Given the progress we have made in executing our restructuring programs, we are poised to continue to grow organically and through targeted and disciplined acquisition.

We also will continue to pursue our long-term growth strategies on a disciplined basis. We are targeting four different dimensions within our targeted growth initiatives to include (1) expansion of existing business platforms; (2) targeted acquisitions; (3) Greenfield development; and (4) privatizations.

All of these areas of opportunity have a common theme which is to leverage our existing strengths and capitalize on favorable market conditions to improve gross margin, earnings per share and cash flows. The catalysts to further growth include both external and internal factors such as:

- Continued electricity demand growth in key markets;
- Attraction of private capital for emerging markets; and

- Government policies that encourage the development of new areas of opportunity including renewable energy.

In each case, we will carefully consider whether proposed transactions have the appropriate risk/reward profile.

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/A. Critical accounting estimates are described in this section. 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 if changes in the estimate that would have a material impact on the Company s financial condition or results of operations are reasonably likely to occur from period to period. Management believes that the accounting estimates employed are appropriate and resulting balances are reasonable; however, actual results could differ from the original estimates, requiring adjustments to these balances in future periods.

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 collectability 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 Taxes 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. A range of these amounts cannot be reasonably estimated at December 31, 2004, as they are primarily unasserted claims.

On October 22, 2004, the American Jobs Creation Act (the AJCA) was signed into law. The AJCA includes a deduction of 85% of certain foreign earnings that are repatriated, as defined in the AJCA. The Company may elect to apply this provision to qualifying earnings repatriations in 2005. The Company has started an evaluation of the effects of the repatriation provision in accordance with recently issued Treasury Department guidance. The Company expects to complete its evaluation early in 2005. The range of possible amounts that the Company is considering for repatriation under this provision is between zero and $150 million. The amount of income tax cannot be reasonably estimated.

Long-Lived Assets

In accordance with SFAS No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets, 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/A, we made our best estimate of fair value using valuation methods based on the most current information at that time. 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/A. 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 review the carrying value of our goodwill annually during the fourth quarter. We also review the carrying value of our goodwill periodically when events and circumstances warrant such a review. This review is performed using estimates of fair value and includes discounted future cash flows. If the carrying value of goodwill is considered impaired, an impairment charge is recorded.

Pension and Postretirement Obligations

Certain of our foreign and domestic subsidiaries maintain defined benefit pension plans which we refer to as the pension plans, or the plans, covering substantially all of their respective employees. Pension benefits are generally based on years of credited service, age of the participant and average earnings. Of the thirteen defined benefit pension plans existing at December 31, 2004, two exist at domestic subsidiaries and eleven exist at foreign subsidiaries. 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 trustee 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
- 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. Although not an estimate, we ve also included sensitivity around the actual return on pension assets. Note that these sensitivities may be asymmetric, and are specific to the base conditions at year-end 2004. 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, 2004 funded status is affected by December 31, 2004 assumptions. Pension expense for 2004 is affected by December 31, 2003 assumptions. The impact on our funded status, equity and U.S. pension expense from a one percentage point change in these assumptions is shown below (in millions):

Increase of 1% in the discount rate	$(10)
Decrease of 1% in the discount rate	$16
Increase of 1% in the long-term rate of return on plan assets	$(11)
Decrease of 1% in the long-term rate of return on plan assets	$11

Regulatory Assets and Liabilities

The Company accounts for its regulated operations located in Brazil and the United States 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 because such 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. 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.

New Accounting Pronouncements

Consolidation of Variable Interest Entities

In January 2003, the Financial Accounting Standards Board (FASB) issued Financial Interpretation No. 46, Consolidation of Variable Interest Entities An Interpretation of ARB No. 51 (FIN 46 or Interpretation). FIN 46 is an interpretation of Accounting Research Bulletin 51 Consolidated Financial Statements, and addresses consolidation by business enterprises of variable interest entities (VIE). The primary objective of the Interpretation is to provide guidance on the identification of and financial reporting for, entities over which control is achieved through means other than voting rights; such entities are known as VIEs. The Interpretation requires an enterprise to consolidate a VIE if that enterprise has a variable interest that will absorb a majority of the entity s expected losses if they occur, receive a majority of the entity s expected residual returns if they occur or both. An enterprise shall consider the rights and obligations conveyed by its variable interests in making this determination. On December 24, 2003, the FASB issued Interpretation No. 46 (Revised 2003) Consolidation of Variable Interest Entities (FIN 46(R) or Revised Interpretation), which partially deferred the effective date of FIN 46 for certain entities and makes other changes to FIN 46, including a more complete definition of variable interest and an exemption for many entities defined as businesses. The Company applied FIN 46 in its financial statements relating to its interest in variable interest entities or potential variable interest entities as of December 31, 2003, and applied FIN 46(R) as of March 31, 2004. The application of FIN 46(R) did not have an impact on the Company s condensed consolidated financial statements for any quarter through December 31, 2004.

Share-Based Payment

In December 2004, the FASB issued a revised SFAS No.123 (SFAS No. 123R), Share-Based Payment, which is a revision of SFAS No. 123. SFAS No. 123R eliminates the intrinsic value method under APB 25 as an alternative method of accounting for stock-based awards by requiring that all share-based payments to employees, including grants of stock options for all outstanding years be recognized in the financial statements based on their fair values. It also revises the fair-value based method of accounting for share-based payment liabilities, forfeitures and modifications of stock-based awards and clarifies SFAS No. 123 s guidance related to measurement of fair value, classifying an award as equity or as a liability and attributing compensation to reporting periods. In addition, SFAS No. 123R amends SFAS No. 95, Statement of Cash Flows, to require that excess tax benefits be reported as a financing cash flow rather than as an operating cash flow.

The Company is required to adopt SFAS No. 123R for the interim period beginning July 1, 2005 using a modified version of prospective application. The Company may apply a modified retrospective application to periods before the required effective date. The Company plans to adopt SFAS No. 123R no later than July 1, 2005, but has not determined what method it will use. Management is currently evaluating the effect of adoption of SFAS No. 123R, but does not expect the adoption to have a material effect on the Company s financial condition, results of operations or cash flows, as the Company had previously adopted income statement treatment for compensation related to share-based payments under SFAS No. 123.

RESULTS OF OPERATIONS

	For The Years Ended December 31, 2004	2003	2002	$ change 2004 vs. 2003	$ change 2003 vs. 2002
	(in millions, except per share data)				
Gross Margin:					
Large Utility	$ 898	$ 783	$ 703	$ 115	$ 80
Growth Distribution	218	193	20	25	173
Contract Generation	1,428	1,262	1,061	166	201
Competitive Supply	238	221	184	17	37
Total gross margin	2,782	2,459	1,968	323	491
General and administrative expenses(1)	(182)	(157)	(112)	(25)	(45)
Interest expense	(1,941)	(1,986)	(1,792)	45	(194)
Interest income	282	280	259	2	21
Other income, net	12	65	57	(53)	8
Loss on sale of investments, asset and goodwill impairment expense	(45)	(212)	(1,211)	167	999
Foreign currency transaction (losses) gains on net monetary position	(147)	99	(644)	(246)	743
Equity in earnings (loss) of affiliates	70	94	(203)	(24)	297
Income tax expense	(375)	(211)	(461)	(164)	250
Minority interest (expense) income	(198)	(120)	75	(78)	(195)
Income (loss) from continuing operations	258	311	(2,064)	(53)	2,375
Income (loss) from operations of discontinued businesses	34	(787)	(1,561)	821	774
Cumulative effect of accounting change		41	(376)	(41)	417
Net income (loss)	$ 292	$ (435)	$(4,001)	$ 727	$ 3,566
PER SHARE DATA:					
Basic income (loss) per share from continuing operations	$ 0.40	$ 0.52	$ (3.83)	$ (0.12)	$ 4.35
Diluted income (loss) per share from continuing operations	$ 0.40	$ 0.52	$ (3.83)	$ (0.12)	$ 4.35

(1) General and administrative expenses are corporate and business development expenses.

Overview

Revenue

	For the Years Ended December 31, 2004 Revenue	% of Total Revenues	2003 Revenue	% of Total Revenues	2002 Revenue	% of Total Revenues
	($ in millions)					
Large Utilities	$ 3,591	38 %	$ 3,294	39 %	$ 3,142	42 %
Growth Distribution	1,306	14 %	1,131	14 %	873	12 %
Regulated	4,897	52 %	4,425	53 %	4,015	54 %
Contract Generation	3,546	37 %	3,108	37 %	2,550	35 %
Competitive Supply	1,020	11 %	880	10 %	812	11 %
Non-Regulated	4,566	48 %	3,988	47 %	3,362	46 %
Total	$ 9,463	100 %	$ 8,413	100 %	$ 7,377	100 %

Revenues increased approximately $1.1 billion, or 12%, to $9.5 billion in 2004 from $8.4 billion in 2003. Excluding the estimated impacts of foreign currency translation effect, revenues would have

increased approximately 11% from 2003 to 2004. The increase in revenues was due to higher tariff rates, increased contract pricing and new projects coming on line. Excluding businesses that commenced commercial operations in 2004 or 2003, revenues increased 11% to $9.3 billion in 2004.

Revenues increased approximately $1.0 billion, or 14%, to $8.4 billion in 2003 from $7.4 billion in 2002. The increase in revenues was due to new operations from Greenfield projects and improvements from existing operations. Excluding businesses that commenced commercial operations in 2003 or 2002, revenues increased 8% to $8.0 billion in 2003.

Gross Margin

	For the Years Ended December 31,					
	2004		2003		2002	
	Gross Margin	% of Total Gross Margin	Gross Margin	% of Total Gross Margin	Gross Margin	% of Total Gross Margin
Large Utilities	$ 898	32 %	$ 783	32 %	$ 703	36 %
Growth Distribution	218	8 %	193	8 %	20	1 %
Regulated	1,116	40 %	976	40 %	723	37 %
Contract Generation	1,428	51 %	1,262	51 %	1,061	54 %
Competitive Supply	238	9 %	221	9 %	184	9 %
Non-Regulated	1,666	60 %	1,483	60 %	1,245	63 %
Total	$ 2,782	100 %	$ 2,459	100 %	$ 1,968	100 %
Gross Margin as a Percent of Revenue	29.4 %		29.2 %		26.7 %	

Gross margin increased $323 million, or 13%, to $2.8 billion in 2004 from $2.5 billion in 2003. This increase was primarily due to the impact of higher revenues in 2004 versus 2003, resulting from higher tariff rates, increased generation contract pricing and new projects coming on line. Excluding businesses that commenced commercial operations in 2004 or 2003, gross margin increased 10% to $2.7 billion in 2004. Gross margin as a percentage of revenues increased to 29.4% in 2004 from 29.2% in 2003.

Gross margin increased $491 million, or 25%, to $2.5 billion in 2003 from $2.0 billion in 2002. Gross margin as a percentage of revenues increased to 29.2% in 2003 from 26.7% in 2002. The increase was primarily due to new operations from Greenfield projects. Excluding businesses that commenced commercial operations in 2003 or 2002, gross margin increased 16% to $2.2 billion in 2003.

Segment Analysis

Large Utilities Revenue

	For the Years Ended December 31,					
	2004		2003		2002	
	Revenue ($ in millions)	% of Total Revenues	Revenue	% of Total Revenues	Revenue	% of Total Revenues
North America	$ 885	9 %	$ 832	10 %	$ 818	11 %
South America	2,087	22 %	1,854	22 %	1,690	23 %
Caribbean*	619	7 %	608	7 %	634	8 %
Total	$ 3,591	38 %	$ 3,294	39 %	$ 3,142	42 %

* Includes Venezuela

The increase in large utility segment revenue in 2004 of $297 million, or 9%, as compared to 2003 was primarily due to the contribution of our Brazilian subsidiary, Eletropaulo, where revenues increased

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$234 million as a result of increased tariffs and favorable exchange rates that were partially offset by lower sales volume. The average customer tariff at Eletropaulo increased in 2004 due to both a rate increase and an increase in residential consumption, although overall consumption decreased by 1%. This net increase in revenue in the large utility segment was also affected by an increase of 6% ($52 million) in revenues at our U.S. subsidiary, IPALCO, due to improved wholesale prices, recoveries of environmental compliance program investments and associated costs and increases in sales volumes. Revenues at our Venezuelan subsidiary, EDC increased 2% ($11 million) due to higher tariffs that were offset substantially by unfavorable exchange rates and reduced sales volumes.

The increase in large utility segment revenue in 2003 of $152 million was primarily due to the consolidation of Eletropaulo for a full fiscal year compared to 11 months in 2002, where revenues increased $163 million compared to 2002. Total sales volume at Eletropaulo increased year over year by approximately 10%, although this was more than offset by a decline in the average customer tariff in 2003 resulting from a decrease in residential consumption. This net increase at Eletropaulo as well as an increase of 2% ($15 million) in revenues at IPALCO was partially offset by a 4% ($26 million) decline in revenues at EDC.

Large Utilities Gross Margin

	For the Years Ended December 31, 2004		2003		2002	
	Gross Margin ($ in millions)	**% of Total Gross Margin**	**Gross Margin**	**% of Total Gross Margin**	**Gross Margin**	**% of Total Gross Margin**
North America	$ 303	11 %	$ 282	11 %	$ 302	15 %
South America	356	13 %	248	11 %	157	9 %
Caribbean*	239	8 %	253	10 %	244	12 %
Total	$ 898	32 %	$ 783	32 %	$ 703	36 %
Large Utilities Gross Margin as a % of Large Utilities Revenue	25.0 %		23.8 %		22.4 %	

* Includes Venezuela

Gross margin from our large utilities segment increased $115 million or 15% in 2004 as compared to 2003, primarily from increases at Eletropaulo and IPALCO, offset by decreases at EDC. Eletropaulo s gross margin improved as the increased tariffs and the favorable effect of exchange rates on revenues were only partially offset by increased costs related to purchased electricity and bad debt provisions. IPALCO s higher margin was due to the favorable effect on revenues of demand and tariffs, coupled with improvements in fuel volumes only partially offset by higher purchased electricity volumes and fixed costs. EDC s gross margin decreased due to the unfavorable effect of exchange rates and lower demand on revenues coupled with higher fixed costs in 2004 compared to 2003. The large utilities segment gross margin as a percentage of large utilities segment revenue increased to 25.0% for 2004 from 23.8% in 2003.

Gross margin from our large utilities segment increased in 2003 due to higher gross margins in South America, which was due to a write-off of approximately $80 million of other receivables at Eletropaulo in 2002. EDC s gross margin increased due to higher demand and increased tariffs in 2003 compared to 2002. IPALCO experienced a lower margin and margin percentage due to milder weather and higher operating and maintenance cost in 2003. The large utilities segment gross margin as a percentage of large utility segment revenue increased to 23.8% for 2003 from 22.4% in 2002.

Growth Distribution Revenue

	For the Years Ended December 31, 2004		2003		2002	
	Revenue ($ in millions)	% of Total Revenues	Revenue	% of Total Revenues	Revenue	% of Total Revenues
South America	$ 491	5 %	$ 414	5 %	$ 263	4 %
Caribbean	352	4 %	343	4 %	311	4 %
Europe/Africa	463	5 %	374	5 %	299	4 %
Total	$ 1,306	14 %	$ 1,131	14 %	$ 873	12 %

Revenue from the growth distribution segment in 2004 increased $175 million, or 15%, as compared to 2003. The principal contributions to the overall revenue growth came from our subsidiary in Cameroon, AES SONEL, where revenue increased by $64 million or 31% and our Brazilian subsidiaries, principally Sul, where revenues increased $62 million or 21%, due to increased customer tariffs, improved demand and favorable exchange rates. Additional contributions by Ukraine, where revenues increased $26 million or 16% as well as El Salvador, where revenue improved by $9 million or 3%, and finally Argentina, whose revenues exceeded 2003 by $18 million or 15%, were due to higher sales volumes and customer tariffs.

Revenue from the growth distribution segment in 2003 increased $258 million as compared to 2002. The most significant component of the increase was due to the impact of the $146 million provision recorded at AES Sul related to a Brazilian regulatory decision. Additional significant contributions to the 2003 increase included an increase of $58 million at AES SONEL in Cameroon resulting from higher customer tariffs in 2003 and increased sales volumes, an increase of $30 million in our El Salvador distribution businesses because of higher sales volumes and increased tariffs and an increase in our Argentine distribution businesses primarily arising from the appreciation of the Argentine peso in 2003.

Growth Distribution Gross Margin

	For the Years Ended December 31, 2004		2003		2002	
	Gross Margin ($ in millions)	% of Total Gross Margin	Gross Margin	% of Total Gross Margin	Gross Margin	% of Total Gross Margin
South America	$ 86	3 %	$ 80	3 %	$ (61)	(3)%
Caribbean	73	3 %	71	3 %	53	2 %
Europe/Africa	62	2 %	45	2 %	31	2 %
Asia	(3)	%	(3)	%	(3)	%
Total	$ 218	8 %	$ 193	8 %	$ 20	1 %
Growth Distribution Gross Margin as a % of Growth Distribution Revenue	16.7 %		17.1 %		2.3 %	

Gross margin from our growth distribution segment increased $25 million, or 13%, in 2004 as compared to 2003, primarily driven by increases in Cameroon, Brazil and Ukraine. In Cameroon, the increase in the margin was caused by higher demand and tariffs offset by higher fixed costs, including a one-time $16 million severance charge taken in 2004. In Brazil and Ukraine, the improved margin was the result of higher tariffs and demand that were substantially offset by higher variable costs, primarily from purchased electricity. Argentina s margin remained stable between 2004 and 2003. The growth distribution gross margin as a percentage of growth distribution segment revenues decreased 0.4% to 16.7% in 2004 from 17.1% in 2003.

Gross margin from our growth distribution segment increased in 2003 due to increases at AES SONEL in Cameroon and CAESS in El Salvador. Additionally, there was a non-recurring charge taken in 2002 for the write-off of $141 million related to MAE settlements at AES Sul in Brazil that did not occur in 2003. The growth distribution gross margin as a percentage of growth distribution segment revenues increased to 17.1% in 2003 from 2.3% in 2002.

Contract Generation Revenue

	For the Years Ended December 31, 2004		2003		2002	
	Revenue ($ in millions)	% of Total Revenues	Revenue	% of Total Revenues	Revenue	% of Total Revenues
North America	$ 884	9 %	$ 876	10 %	$ 852	12 %
South America	1,118	12 %	922	11 %	850	12 %
Caribbean	542	5 %	493	6 %	180	2 %
Europe/Africa	432	5 %	415	5 %	365	5 %
Asia	570	6 %	402	5 %	303	4 %
Total	$ 3,546	37 %	$ 3,108	37 %	$ 2,550	35 %

Revenue from the contract generation segment for 2004 increased $438 million, or 14%, over 2003 primarily due to increased contract pricing at Tietê in Brazil (consisting of a group of hydro-electric plants providing electricity primarily to Eletropaulo), Gener in Chile, Kilroot in Northern Ireland and Merida III in Mexico. The completion of Ras Laffan s power and water desalination plant in Qatar contributed significantly to the increase in revenues as well as the reporting of a full year s operating results for businesses that came on line in 2003 (Barka in Oman and Andres in the Dominican Republic). Excluding the estimated impacts of foreign currency translation effect, revenues would have increased approximately 12% from 2003 to 2004. Favorable foreign currency translation effects positively impacted revenues at Kilroot in Northern Ireland, Tietê in Brazil, Tisza in Hungary and Gener in Chile. These revenue increases were partially offset by lower volumes at Tisza in Hungary as a result of outages to perform plant upgrades in 2004.

Revenue from the contract generation segment for 2003 increased $558 million over 2002 primarily due to the addition of recently completed businesses including Red Oak in New Jersey (which reported results from operations for a full year), Puerto Rico L.P. in Puerto Rico, Kelanitissa in Sri Lanka, Barka in Oman, Ras Laffan in Qatar and Andres in the Dominican Republic. Together, these businesses contributed $407 million, or 73%, of the increase for 2003. Revenues also improved over the same time period at Los Mina in the Domincan Republic, Merida III in Mexico, Tisza in Hungary, Gener in Chile, and Tietê in Brazil. These improvements were offset by declines at Shady Point in Oklahoma, due to a scheduled decrease in the contracted capacity payment, and at Lal Pir and Pak Gen in Pakistan, because of lower energy dispatch in 2003.

Contract Generation Gross Margin

	For the Years Ended December 31, 2004 Gross Margin ($ in millions)	2004 % of Total Gross Margin	2003 Gross Margin	2003 % of Total Gross Margin	2002 Gross Margin	2002 % of Total Gross Margin
North America	$ 396	14 %	$ 415	17 %	$ 426	22 %
South America	482	18 %	383	15 %	314	16 %
Caribbean	146	5 %	127	5 %	32	2 %
Europe/Africa	148	5 %	140	6 %	147	7 %
Asia	256	9 %	197	8 %	142	7 %
Total	$ 1,428	51 %	$ 1,262	51 %	$ 1,061	54 %
Contract Generation Gross Margin as a % of Contract Generation Revenue	40.3 %		40.6 %		41.6 %	

Gross margin from our contract generation segment increased $166 million, or 13%, in 2004 as compared to 2003 primarily due to increased contract pricing escalations at Tietê in Brazil, Gener in Chile, Kilroot in Northern Ireland and Merida III in Mexico. The completion of Ras Laffan s power and water desalination plant in Qatar contributed significantly to the increase in gross margin as well as the reporting of a full year s operating results for businesses that came on line in 2003 (Barka in Oman and Andres in the Dominican Republic). This gross margin increase was partially offset by higher fuel costs at Gener in Chile, Merida III in Mexico and Kilroot in Northern Ireland, as well as by increased depreciation and other fixed costs. The contract generation gross margin as a percentage of revenues slightly decreased to 40.3% in 2004 from 40.6% in 2003.

Gross margin from our contract generation segment increased in 2003 because of improvements at Tietê in Brazil, and Ebute in Nigeria compared to 2002. Additionally, new plants came online and contributed to the increase. These new plants include Red Oak in New Jersey, Puerto Rico L.P. in Puerto Rico, Kelanitissa in Sri Lanka, Barka in Oman, Ras Laffan in Qatar and Andres in the Dominican Republic. These increases were partially offset by declines in gross margin at Beaver Valley and Ironwood in Pennsylvania, Shady Point in Oklahoma, Kilroot in Northern Ireland and the Chigen plants in China. The contract generation gross margin as a percentage of contract generation revenues decreased to 40.6% in 2003 from 41.6% in 2002.

Competitive Supply Revenue

	For the Years Ended December 31, 2004 Revenue ($ in millions)	2004 % of Total Revenues	2003 Revenue	2003 % of Total Revenues	2002 Revenue	2002 % of Total Revenues
North America	$ 446	5 %	$ 451	5 %	$ 417	6 %
South America	178	3 %	110	1 %	74	1 %
Caribbean	122	1 %	84	1 %	69	1 %
Europe/Africa	137	1 %	132	2 %	162	2 %
Asia	137	1 %	103	1 %	90	1 %
Total	$ 1,020	11 %	$ 880	10 %	$ 812	11 %

Revenue from our competitive supply segment for 2004 increased $140 million, or 16%, over 2003 primarily due to the significantly higher than expected dispatch of AES s coal-fired plant in Argentina, CTSN, as a result of increased demand caused by gas shortages in Argentina. The completion of AES s Greenfield hydroelectric project in Panama (Esti), combined with the expansion of another hydroelectric project in Panama (Bayano), resulted in increased revenues. Higher competitive market prices for electricity sold at Parana in Argentina, Ekibastuz in Kazakhstan and CTSN in Argentina also contributed to this revenue growth. Excluding the estimated impacts of foreign currency translation effect, revenues would have increased approximately 13% from 2003 to 2004. Favorable foreign currency translation effects positively impacted revenues at Borsod in Hungary, Altai and Ekibastuz in Kazakhstan, and Ottana in Italy.

Revenue from our competitive supply segment for 2003 increased $68 million over 2002 due primarily to an increase of $54 million in the revenues at our New York plants, where average competitive market prices for electricity sold by those plants increased approximately 29% over 2002. The remaining net increase resulted from improvements at several other plants including Alicura and Parana in Argentina, Panama in the Caribbean and Ekibastuz in Kazakhstan. These increases were partially offset by decreased revenues from Deepwater in Texas due to an extended outage in 2003 and the termination of a small retail electricity business in the U.K. in early 2003.

Competitive Supply Gross Margin

	For the Years Ended December 31, 2004		2003		2002	
	Gross Margin ($ in millions)	% of Total Gross Margin	Gross Margin	% of Total Gross Margin	Gross Margin	% of Total Gross Margin
North America	$ 92	3 %	$ 113	5 %	$ 96	4 %
South America	64	3 %	44	2 %	20	1 %
Caribbean	42	2 %	36	1 %	32	2 %
Europe/Africa	4	%	3	%	17	1 %
Asia	36	1 %	25	1 %	19	1 %
Total	$ 238	9 %	$ 221	9 %	$ 184	9 %
Competitive Supply Gross Margin as a % of Competitive Supply Revenue	23.3 %		25.1 %		22.7 %	

Gross margin from our competitive supply segment increased $17 million, or 8%, in 2004 as compared to 2003 primarily due to the significantly higher dispatch of AES s coal-fired plant in Argentina, CTSN, as well as the completion of AES s Greenfield and expansion hydroelectric projects in Panama. Higher competitive market prices for electricity sold at Parana in Argentina, Ekibastuz in Kazakhstan and CTSN in Argentina also contributed to this gross margin growth. The competitive supply gross margin as a percentage of competitive supply revenues decreased to 23.3% in 2004 from 25.1% in 2003. This decrease was primarily due to higher fuel costs for our businesses in the U.S. (New York) and in South America (Parana), as well as increased depreciation and other fixed costs for our new Greenfield and expansion hydroelectric projects in Panama.

Gross margin from our competitive supply segment increased in 2003 due to improvements at the New York plants, CTSN and Parana in South America and Altai in Asia. These increases were partially offset by lower margins and margin percentages at Deepwater in Texas and Borsod in Hungary. The competitive supply gross margin as a percentage of competitive supply revenues increased to 25.1% in 2003 from 22.7% in 2002.

General and administrative expenses

General and administrative expenses increased $25 million, or 16% to $182 million in 2004 from 2003 and also increased $45 million, or 40% to $157 million in 2003 from 2002. General and administrative expenses as a percentage of total revenues remained at 2% in 2004, 2003 and 2002. The increases are a result of additional corporate personnel and expensing of annual awards of stock options and other long-term incentive compensation. Additional personnel have been added at the parent company over the past two years to support our key initiatives related to strategy, safety, compliance, information systems and controls. In addition, a higher level of consulting costs were incurred in 2004 and 2003 respectively related to our internal controls reviews as a result of Sarbanes-Oxley and other consulting costs related to implementation of our new corporate initiatives.

Interest expense

Interest expense decreased $45 million, or 2%, to $1,941 million in 2004 from $1,986 million in 2003. Interest expense as a percentage of revenues decreased from 24% in 2003 to 21% for 2004. Interest expense decreased primarily due to a reduction of debt associated with the Brazil debt restructuring completed at the end of 2003 and debt refinancings and paydowns offset by interest expense from new projects coming on-line in 2004, new project financings and unfavorable foreign currency translation and inflation adjustment impacts.

Interest expense increased $194 million, or 11%, to $1,986 million in 2003 from $1,792 million in 2002. Interest expense as a percentage of revenues remained at 24% in 2003 and 2002. Increases due to accrual of $194 million of default interest at Eletropaulo, inflation adjustments related to debt at Tiete (a Brazilian generation company), increased interest at Corporate due to higher rates on refinanced debt and interest from Greenfield projects that were brought on-line in late 2002 or 2003 were slightly offset by lower interest at Southland due to lower rates and no interest expense for Cemig due to the deconsolidation of that entity in 2002.

Interest income

Interest income increased $2 million to $282 million in 2004 from $280 million in 2003. Interest income as a percentage of revenues remained constant at 3% in 2004 and 2003. Interest income increased primarily due to favorable foreign currency translation and higher interest on spot market and customer receivables offset by a reclassification adjustment associated with the Eletropaulo settlement of certain outstanding municipal receivables.

Interest income increased $21 million, or 8%, to $280 million in 2003 from $259 million in 2002. Interest income as a percentage of revenues was 3% in 2003 and 4% in 2002. The increase in interest income during 2003 was due primarily to a $58 million increase in interest earnings in Eletropaulo related to its regulatory asset and accounts receivable. The increase in Eletropaulo in 2003 over 2002 was partially offset by a general decline in interest earnings due to lower interest rates.

Other income

Other income decreased $8 million to $163 million in 2004 from $171 million in 2003. Other income in 2004 primarily consists of a $64 million gain on debt extinguishment related to one of our businesses in Argentina, $21 million for gains on settlement of disputes and $13 million for gains on the sale of assets. Included in 2003 was approximately $141 million related to gains on extinguishment of debt and $30 million of other income.

Other income increased $27 million to $171 million in 2003 from $144 million in 2002. Activity in 2003 was driven by $141 million related to gains on extinguishment of debt and $30 million of other income. There were $61 million related to gains on extinguishment of debt in 2002 along with $29 million for mark-to-market on commodity derivatives and $12 million for gains on the sale of assets. See Note 15 to the Consolidated Financial Statements included in Item 8 of this Form 10-K/A for an analysis of other income.

Other expense

Other expense increased $45 million to $151 million in 2004 from $106 million in 2003. Other expense primarily consists of losses on the sale of assets, losses associated with the early extinguishment of debt and dispute settlements.

Other expense increased $19 million to $106 million in 2003 from $87 million in 2002. Approximately $57 million of other expense recorded in 2003 was attributable to mark-to-market loss on commodity derivatives and debt refinancing costs. See Note 15 to the Consolidated Financial Statements included in Item 8 of this Form 10-K/A for an analysis of other expense.

Loss on sale of investments and asset impairments

Loss on sale of investments and asset impairment expense was $45 million in 2004 compared to $201 million in 2003 primarily from fewer impairment charges being taken in 2004. The amount of asset impairment expense for 2004, includes the write-off of $25 million of capitalized costs associated with a fertilizer development project at our Deepwater facility in Texas. This project was terminated in the fourth quarter of 2004. It also includes a $15 million asset impairment charge taken to reflect the net realizable value of an investment in one of our Chinese businesses which we expect to sell.

Loss on sale of investments and asset impairment expense decreased to $201 million in 2003 compared to $473 million in 2002 primarily from fewer impairment charges being taken in 2003. In 2003, the following actions were taken which led to the recording of impairment charges:

- In December 2003, we sold an approximate 39% ownership interest in AES Oasis Limited (AES Oasis) for cash proceeds of approximately $150 million. The loss realized on the transaction was approximately $36 million before income taxes. AES Oasis is an entity that owns an electric generation project in Oman (AES Barka) and two oil-fired generating facilities in Pakistan (AES Lal Pir and AES Pak Gen). AES Barka, AES Lal Pir, and AES Pak Gen are all contract generation businesses.

- During the fourth quarter of 2003, we decided to discontinue the development of Zeg, a contract generation plant under construction in Poland. In connection with this decision, we wrote-off our investment in Zeg of approximately $23 million before income taxes.

- In August 2003, we decided to discontinue the construction and development of AES Nile Power in Uganda (Bujagali). In connection with this decision, we wrote-off our investment in Bujagali of approximately $76 million before income taxes in the third quarter of 2003.

- During the second quarter of 2003, we wrote off capitalized costs of approximately $20 million associated with our development project in Honduras when we elected to offer the project for sale after consideration of existing business conditions and future opportunities. The project consisted of a 580 MW combined-cycle power plant fueled by natural gas, a liquefied natural gas import terminal with storage capacity of one million barrels and transmission lines and line upgrades. The project was sold in January 2004.

- Additionally, during 2003, we recorded $16 million of other losses which resulted from the sale of assets to third parties, and $29 million of other asset impairment charges taken to reflect the net realizable value of discontinued development projects and other non-recoverable assets.

In 2002, the following impairment charges were taken:

- In the fourth quarter of 2002, we decided not to provide any further funding to Lake Worth, a 205 MW gas plant in Florida, and to sell the project. Subsequently the project entered into

bankruptcy. As a result, the carrying amount of AES s investment in the Lake Worth project was not expected to be recovered. Therefore, in accordance with SFAS No. 144, a pre-tax impairment charge of $78 million was recorded to write-down the net assets of Lake Worth to their net realizable value.

- In September 2002, AES Greystone, L.L.C. and its subsidiary Haywood Power I, L.L.C., sold the Greystone gas-fired peaker assets then under construction in Tennessee to Tenaska Power Equipment for $36 million including cash and assumption of certain obligations. With this sale, AES and its subsidiaries have eliminated any future capital expenditures related to the facility, and also settled all major outstanding obligations with parties involved in this project. We recorded a loss of approximately $168 million associated with this sale. Greystone was previously recorded as a competitive supply business.

- Additionally, during 2002, we recorded $116 million of other losses which resulted from the sale of assets to third parties, and $111 million of other asset impairment charges taken to reflect the net realizable value of discontinued development projects and other non-recoverable assets.

Goodwill impairment expense

During 2003, we recorded a goodwill impairment charge of $11 million primarily related to all of the goodwill at Atlantis, an aragonite mining operation in the Caribbean. The write-off was due to a reduction in the fair value of the business below its carrying value due to a slow down of operations from the termination of sales contracts that have not been replaced.

During 2002, we recorded a goodwill impairment charge of $738 million primarily related to goodwill at Eletropaulo in Brazil. The fair value of the business was less than the carrying value due to slower than anticipated recovery to pre-rationing electricity consumption levels and lower electricity prices due to devaluation of foreign exchange rates.

Foreign currency transaction (losses) gains on net monetary position

The Company recognized foreign currency transaction losses of $147 million in 2004 compared to gains from foreign currency transactions of $99 million in 2003. The $246 million decrease for 2004 as compared to 2003 was primarily related to losses in Brazil, Argentina, and the Dominican Republic. Foreign currency transaction losses increased primarily due to lower annual appreciation in 2004 of the Brazilian real of 7.5% compared to 23.7% in 2003 contributing to $182 million of the change year over year. The Argentine peso devalued 1.7% during 2004 thereby contributing $46 million of losses to the overall change. Additionally, the Dominican peso appreciated 31.2% during 2004. This is related to one of our Dominican businesses which has a net monetary liability position denominated in the Dominican peso. This appreciation in the Dominican peso contributed to the change year over year by $28 million in losses.

The Company recognized foreign currency transaction gains of $99 million in 2003 compared to a loss of $644 million in 2002. This $743 million increase related to exchange rate changes in Brazil, Argentina and Venezuela. Foreign currency transaction gains increased primarily due to a 23.7% appreciation of the Brazilian real during 2003 compared to devaluation of 33.5% during 2002. This appreciation resulted in gains in 2003 compared to losses in 2002 and an overall change of $434 million. Additionally, the Argentine peso appreciated 13.3% during 2003. This appreciation resulted in gains in 2003 compared to losses in 2002 and an overall change of $243 million. These gains were offset by foreign currency transaction losses recorded at EDC during 2003 due to a 12% devaluation of the Venezuelan bolivar and a year over year change of $64 million. Since EDC uses the U.S. dollar as its functional currency and a portion of its debt is denominated in the Venezuelan bolivar, EDC will experience gains when the currency devalues.

Equity in earnings (losses) of affiliates

Equity in earnings of affiliates decreased $24 million, or 26%, to $70 million in 2004 from $94 million in 2003. The decrease was primarily due to the sale of our ownership in Medway Power Ltd. in 2003 offset by slight increases from Chigen in our contract generation business.

Equity in earnings (losses) of affiliates increased $297 million, or 146%, to income of $94 million in 2003 compared to a loss of $203 million in 2002. The overall increase was due primarily to the change of control in February 2002 of Eletropaulo, and an impairment charge taken for an other than temporary decline in the value of CEMIG in 2002.

Income taxes

Income tax expense related to continuing operations increased $164 million to $375 million in 2004 from $211 million in 2003. The Company s effective tax rates were 45% for 2004 and 33% for 2003. The effective tax rate increased in 2004 due to the impact of increasing certain deferred tax valuation allowances and the treatment of unrealized foreign currency gains on U.S. dollar debt held by certain of our Latin American subsidiaries.

Income tax expense related to continuing operations decreased to $211 million in 2003 from $461 million in 2002. The effective tax rate was 33% in 2003 versus (27)% in 2002. (The Company recorded tax expense in 2002 on a loss from continuing operations). The 2002 effective tax rate was impacted by the inclusion in income from continuing operations of significant book write-offs related to goodwill and other asset impairments that were not deductible for income tax purposes.

Minority interest

Minority interest expense increased $78 million to $198 million in 2004 from $120 million in 2003. The increase is primarily due to the sale of stock by our subsidiary in Brazil, the sale of a portion of our interest in Oasis and higher earnings for Ras Laffan being allocated to the minorities since the project came on-line in 2004.

Minority interest expense increased $195 million to $120 million in 2003 from minority interest income of $75 million in 2002. The increase is primarily due to the deconsolidation of CEMIG in 2002 and recording more losses related to Parana due to the minority owners investment being reduced to zero in 2003.

Discontinued operations

Income from operations of discontinued businesses, net of tax, was $34 million in 2004 related to the sales of Whitefield, AES Communications Bolivia, Colombia I, Ede Este, Wolf Hollow, Carbones Internacionales del Cesar S.A. and Granite Ridge. All of these entities had originally been recorded in discontinued operation in either 2003 or 2002. Additionally, in 2004, as a result of filing our 2003 tax returns, previously recorded estimates of the tax effect of the discontinued businesses were adjusted to reflect the final tax returns. As a result, favorable tax adjustments are reflected in the net income of discontinued operations. As of December 31, 2004, no further businesses were classified as discontinued operations.

Loss from operations of discontinued businesses, net of tax, was $787 million in 2003. During 2003, we discontinued certain of our operations including Haripur, Meghnaghat, Barry, Telasi, Mtkvari, Khrami, Drax, Whitefield, AES Communications Bolivia, Granite Ridge, Ede Este, Wolf Hollow and Colombia I. We closed the sale of Barry in September 2003, Telasi, Mtkvari and Khrami in August 2003 and Haripur and Meghnaghat in December 2003.

Loss from operations of discontinued businesses, net of tax, was $1,561 million in 2002. During 2002, we discontinued certain of our operations including Fifoots, CILCORP, NewEnergy, Eletronet, Mt. Stuart, Ecogen, two Altai businesses, Mountainview and Kelvin. We closed the sale of both CILCORP and Mt. Stuart in January 2003 and the sale of Ecogen in February 2003.

Change in accounting principle

On January 1, 2003, we adopted SFAS No. 143, Accounting for Asset Retirement Obligations which requires companies to record the fair value of a legal liability for an asset retirement obligation in the period in which it is incurred. The items that are part of the scope of SFAS No. 143 for our business primarily include active ash landfills, water treatment basins and the removal or dismantlement of certain plant and equipment. The adoption of SFAS No. 143 resulted in a cumulative reduction to income of $2 million, net of income tax effects.

On October 1, 2003, we adopted Derivative Implementation Group (DIG) Issue C-20 which superseded and clarified DIG Issue C-11 regarding the treatment of power sales contracts. As a result of this adoption, we had a Power Purchase Agreement (PPA) that was previously treated as a normal sales and purchase contract that was treated as a derivative instrument under SFAS No. 133 and marked-to-market upon adoption of DIG Issue C-20. The prospective method of accounting for this PPA requires no further mark-to-market treatment, and the initial mark-to-market adjustment will be subsequently amortized over the life of the contract. The adoption of DIG Issue C-20, effective October 1, 2003 results in a cumulative increase to income of $43 million, net of income tax effects.

On April 1, 2002, we adopted Derivative Implementation Group (DIG) Issue C-15 which established specific guidelines for certain contracts to be considered normal purchases and normal sales contracts under SFAS No. 133. As a result of this adoption, we had two contracts which no longer qualified as normal purchases and normal sales contracts and were required to be treated as derivative instruments under SFAS No. 133. The adoption of DIG Issue C-15, effective April 1, 2002, resulted in a cumulative increase to income of $127 million, net of income tax effects.

Effective January 1, 2002, we adopted SFAS No. 142, Goodwill and Other Intangible Assets which established accounting and reporting standards for goodwill and other intangible assets. The adoption of SFAS No. 142 resulted in a cumulative reduction to income of $503 million, net of income tax effects. SFAS No. 142 adopts a fair value model for evaluating impairment of goodwill in place of the recoverability model used previously. We wrote-off the goodwill associated with certain acquisitions where the current fair market value of such businesses was less than the current carrying value of the business, primarily as a result of reductions in fair value associated with lower than expected growth in electricity consumption compared to the original estimates made at the date of acquisition.

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 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, 2004, we had $5.2 billion of recourse debt and $13.4 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/A.

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. Similarly, in certain of our businesses, we may provide financial guarantees or other credit support for the benefit of counterparties who have entered into contracts for the purchase or sale of electricity 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 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 counter-parties. 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, 2004, 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 $562 million (including those collateralized by letters of credit and other obligations discussed below).

At December 31, 2004, we had $98 million in letters of credit outstanding, which operate to guarantee performance relating to certain project development activities and subsidiary operations. All of these letters of credit were provided under our revolver. We pay letter of credit fees ranging from 0.5% to 3.5% per annum on the outstanding amounts. In addition, we had $4 million in surety bonds outstanding at December 31, 2004.

Many of our subsidiaries including those in Central and South America 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 of our businesses in Brazil and Venezuela. 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.

Capital Expenditures

We spent $892 million and $1,228 million on capital expenditures in 2004 and 2003, respectively. We anticipate capital expenditures during 2005 to approximate the amount in 2004. 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 2005 are expected to be financed using internally generated cash provided by operations and project level financing.

Cash Flows

At December 31, 2004, we had $1,281 million of cash and cash equivalents representing a decrease of $382 million from December 31, 2003. The Company paid down in excess of $700 million of debt and funded approximately $900 million of property additions from operating cash flow generated this year and the use of some of our existing cash balances.

Operating Activities

	2004 (in millions)	2003	Change
Increase in accounts receivable	$ (128)	$ (101)	$ (27)
Increase in inventory	(33)	(2)	(31)
Decrease in prepaid expenses and other current assets	7	180	(173)
Increase in accounts payable and accrued liabilities	226	697	(471)
Total working capital	$ 72	$ 774	$ (702)

The cash flows provided by operating activities totaled $1,571 million during 2004, which was $71 million lower than 2003. The primary reason for the slight decrease in cash flows from operations was an increase in net earnings (adjusted for non-cash items) of $605 million, a $26 million change in other assets and liabilities, offset by $702 million of changes in working capital. The working capital change was mainly driven by changes in prepaid expenses and other current assets and accounts payable and accrued liabilities. The change in prepaid expenses and other current assets is being driven by our large utilities segment. The change is related to a settlement of a receivable from the Brazilian Wholesale Electricity Market (MAE) regulatory body in 2003 for energy capacity that was sold in the market in the prior year when demand for energy was low. In 2004, the settlement from MAE was much less as the demand for electricity stabilized. The change in accounts payable and accrued liabilities also was driven by our large utilities and contract generation segments. In the large utilities segment, the majority of the change is due to the payment of outstanding prior year payables in 2004 after the debt restructuring in Brazil. Our business in Venezuela experienced a slow down in accounts payable payments at the end of 2003 due to the political situation in that country. Those payments were caught up on in the beginning of 2004. In the contract generation segment we had a build up in 2003 of construction liabilities at one of our plants in the Middle East due to the plant approaching its commercial operations date. When the plant began operations in 2004 the construction related liabilities were paid. In addition, accounts payable and accrued liabilities were impacted by our tax restatement which resulted in a decrease in current tax liabilities.

Investing Activities

Net cash used in investing activities totaled $1,025 million during 2004. The cash used in investing activities includes $892 million for property additions, an increase in debt service reserve and other assets of $151 million, and other cash inflows of $18 million. The increase in cash flows used in investing activities is due to an increase in debt service reserves and other assets of $123 million from the prior year and a reduction in the proceeds from the sale of assets of $1,023 million. This is offset by a reduction from 2003 in property additions and restricted cash of $336 million and $182 million respectively.

Debt service reserves and other assets increased mainly as a result of the construction activity at our Cartagena plant due to increased equity contributions which were placed into an escrow deposit. In 2003, we received approximately $898 million of proceeds from the sale of our subsidiaries. The decrease in property additions in 2004 is attributable to the completion of construction projects in the Caribbean and Middle East of $193 million and $68 million respectively.

Financing Activities

Net cash used in financing activities was $936 million during 2004, which primarily consists of refinancing and principal payments cash outflow of $734 million, net of issuances, and payments for deferred financing costs of $109 million. The increase in cash used in financing activities in 2004 primarily reflects the reduction in our borrowings of $1,674 million compared to 2003 and the decline in proceeds from the issuance of stock. We reduced our borrowings by approximately $2 billion on our parent recourse debt in comparison to borrowings in 2003. In 2004 we received $16 million in proceeds from stock option exercises compared to proceeds of $334 million in 2003 from our stock offering and proceeds of $3 million from stock option exercises.

Contractual Obligations

A summary of the Company s contractual obligations, commitments and other liabilities as of December 31, 2004 is presented in the table below.

Contractual Obligations	Total	Less then 1 year	2-3 years	3-5 years	After 5 years	Footnote Reference
Debt Obligations(1)	$ 18,588	1,761	2,679	2,962	11,186	8
Capital Lease Obligations(2)	83	5	9	9	60	10
Other Long-term Liabilities Reflected on AES s Consolidated Balance Sheet under GAAP(3)	70	14	34	5	17	n/a
Operating Lease Obligations(4)	149	10	19	18	102	10
Sale Leaseback Obligations(5)	1,436	59	124	126	1,127	10
Purchase Take-or-Pay Obligations(6)	18,367	982	1,966	2,209	13,210	10
Fuel Contract Obligations(7)	10,386	916	1,504	1,210	6,756	10
Other(8)	292	114	59	64	55	
Total	$ 49,371	$ 3,861	$ 6,394	$ 6,603	$ 32,513	

(1) Debt Obligations Debt obligations includes non-recourse debt and recourse debt presented on our consolidated financial statements. Non-recourse debt borrowings are not a direct obligation of The AES Corporation, 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 financings, working capital facilities and all other consolidated debt of the subsidiaries. Recourse debt borrowings are the borrowings of The AES Corporation, the parent company. Note 8 to the Consolidated Financial Statements included in Item 8 of this Form 10-K/A provides disclosure of these obligations.

(2) Capital Lease Obligations One of AES s subsidiaries, AES Indian Queens Power Limited, conducts a major part of its operations from leased facilities. The plant lease is for 25 years expiring in 2022. In addition, several AES subsidiaries lease operating and office equipment, and vehicles. The total capital lease obligation of $83 million represents the future minimum lease commitments. The present value of the capital lease obligations included in the consolidated balance sheet totals $48 million. Imputed interest for these obligations total $35 million.

(3) Other long-term liabilities reflected on AES s consolidated balance sheet under GAAP include only those amounts in long-term liabilities reflected on the Company s consolidated balance sheet 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 than pension employee benefit liabilities (see Note 12 to the Consolidated Financial Statements included in Item 8 of this Form 10-K/A).

(4) As of December 31, 2004, 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 (5).

(5) 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.

(6) Some of our operating subsidiaries have entered into take-or-pay contracts for the purchase of electricity from third parties.

(7) Some of our operating subsidiaries have entered into various long-term contracts for the purchase of fuel subject to termination only in certain limited circumstances.

(8) 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 transaction. Included in the total amount is (1) $149 million of other take-or-pay contracts denoted in Note 10 to the Consolidated Financial Statements in Item 8 of this Form 10-K/A, (2) $44 million of capital costs of AEE, a U.S. subsidiary of the Company, to install the MCP Project at Greenidge Unit 4 denoted in Item 3 of this Form 10-K/A, and (3) $99 million related to other service and fuel contracts. These amounts also exclude planned capital expenditures that are not contractually obligated.

Parent Company Liquidity

Because of the non-recourse nature of most of our indebtedness, we believe 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 revolving credit facility; and
- proceeds from asset sales.

Our cash requirements at the parent company level through the end of 2004 are primarily to fund:

- interest and preferred dividends;
- principal repayments of debt;
- construction commitments;
- other equity commitments;
- taxes; and
- parent company overhead and development costs.

During the past three years, we undertook numerous actions designed to increase parent liquidity, lengthen parent debt maturities, and reduce parent debt and other contractual obligations, both contingent and non-contingent. These actions are consistent with our strategic goals of improving the credit profile of both the parent and the consolidated company in order to reduce our financial risk and improve our credit rating by the major rating agencies. Parent liquidity was as follows at December 31, 2004, 2003 and 2002:

	2004	2003	2002
	(in millions)		
Cash and cash equivalents	$ 1,281	$ 1,663	$ 740

Less: cash and cash equivalents at subsidiaries	994	798	552
Parent cash and cash equivalents	287	865	188
Borrowing available under revolving credit facility	352	180	18
Cash at qualified holding companies	4	25	10
Total parent liquidity	$ 643	$ 1,070	$ 216

Our parent recourse debt at year-end was approximately $5.2 billion, $5.9 billion, and $6.8 billion in 2004, 2003 and 2002, respectively. Our contingent contractual obligations were $562 million, $608 million, and $871 million at the end of 2004, 2003 and 2002, respectively.

The primary actions we undertook in 2004 at the parent level to achieve these goals included: (i) exchanging common stock for recourse debt, (ii) refinancing recourse debt to mature at later dates, (iii) reducing interest costs associated with our senior secured credit facilities, and (iv) redeeming recourse debt.

In February 2004, we called for redemption of $155 million aggregate principal amount of outstanding 8% senior notes due 2008, which represents the entire outstanding principal amount of the 8% senior notes due 2008, and $34 million aggregate principal amount of outstanding 10% secured senior notes due 2005.

In February 2004, we issued $500 million of unsecured senior notes bearing a coupon rate of 7.75%. The unsecured senior notes mature in 2014 and are callable at our option at any time at a redemption price equal to 100% of the principal amount of the unsecured senior notes plus a make-whole premium. The unsecured senior notes were issued at a price of 98.288% and pay interest semi-annually.

In March 2004, we increased the size of our secured revolving credit facility from $250 million to $450 million through an expanded group of global financial institutions. We also negotiated amendments to our secured bank agreement, which includes the revolving credit facility and a $200 million secured term loan.

In August 2004, we amended our $650 million credit facilities to reduce borrowing costs under the facilities. The interest rate on the $450 million revolving facility was reduced to LIBOR plus 2.5% and the interest rate on the $200 million term loan was reduced to LIBOR plus 2.25%. Previously, borrowings under both facilities were LIBOR plus 4%. In addition, the term loan maturity was extended from 2007 to 2011. The revolving credit facility s maturity date of 2007 remained unchanged. These amendments modified various prepayment provisions.

In December 2004, we redeemed all of the remaining $153 million of our 10% senior secured notes due 2005, all of the remaining $113 million of our 8.375% senior subordinated notes due 2007, and a portion of our 8.5% senior subordinated notes due 2007 amounting to $66 million.

At various times during the first three quarters of 2004, we issued an aggregate of 19.7 million common shares of AES in exchange for $165 million of aggregate principal amount of various series of recourse debt at the parent level.

In addition, the Company redeemed an additional aggregate amount of approximately $45 million of the 10% senior secured notes due 2005. These redemptions were in accordance with various mandatory prepayments contained in the indentures of those securities.

At various times during the first three quarters the company retired an additional aggregate amount of $69 million of various series of recourse debt at the parent level through open market repurchases.

As a result of the actions described above, we reduced recourse debt by approximately $800 million and increased our average term of our recourse debt maturities from 8.9 years at December 31, 2003 to 9.2 years at December 31, 2004.

The following table sets forth our parent company contingent contractual obligations as of December 31, 2004:

Contingent contractual obligations	Amount ($ in millions)	Number of Agreements	Exposure Range for Each Agreement
Guarantees	$ 460	46	<$1 - $100
Letters of credit under the Revolver	98	20	<$1 - $ 42
Surety bonds	4	5	<$1 - $ 3
Total	$ 562	71	

We have a varied portfolio of performance related contingent contractual obligations. Amounts related to the balance sheet items represent credit enhancements made by us at the parent company level and by other third parties for the benefit of the lenders associated with the non-recourse debt recorded as liabilities in the accompanying consolidated balance sheets. 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, political risk, tax indemnities, spot market power prices, supplier 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 2004 or beyond that are not recorded on the balance sheet, many of the events which would give rise to such an obligation 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 2005, this belief is based on a number of material assumptions, including, without limitation, assumptions about exchange rates, power market pool prices and the ability of our subsidiaries to pay dividends. In addition, our project subsidiaries ability to declare and pay cash dividends to us (at the parent company level) is subject to certain limitations contained in project 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 a secured revolving credit facility of $450 million. We did not have any outstanding borrowings under the revolving credit facility at December 31, 2004. At December 31, 2004, we had $98 million of letters of credit outstanding under the revolving credit facility.

Various debt instruments at the parent company level, including our senior secured credit facilities, senior secured notes and senior subordinated notes 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; and
- maintenance of certain financial ratios.

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 revolving credit agreement and outstanding senior notes, senior subordinated notes and junior subordinated notes 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 $291 million at December 31, 2004.

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 an 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 senior notes, senior subordinated notes and junior subordinated notes.

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 2004, 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. As of December 31, 2004, we fulfilled a lease requirement on the subsidiary s behalf by funding an additional liquidity account, as defined in the lease agreement, in the form of a $36 million letter of credit. However, the subsidiary is required to replenish or replace this letter of credit in the event it is drawn upon or requires replacement. 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/A for a more complete discussion of this transaction.

Our subsidiary IPL formed IPL Funding Corporation (IPL Funding) in 1996 to purchase, on a revolving basis, up to $50 million of the retail accounts receivable and related collections of IPL in exchange for a note payable. IPL Funding is not consolidated by IPL or IPALCO since it meets requirements set forth in SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities to be considered a qualified special-purpose entity. IPL Funding has entered into a 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 the receivables purchased from IPL. During 2004, this agreement was extended through October 26, 2005. As of December 31, 2004 and 2003, the aggregate amount of receivables IPL has sold to IPL Funding and IPL Funding has sold to the Purchasers pursuant to this purchase facility was $50 million. Accounts receivable on our accompanying consolidated balance sheets are stated net of the $50 million sold.

The net cash flows between IPL and IPL Funding are limited to cash payments made by IPL to IPL Funding for interest charges and processing fees. These payments totaled $1 million for each of the three years ended December 31, 2004, 2003 and 2002, respectively. IPL retains servicing responsibilities through its role as a collection agent for the amounts due on the purchased receivables. 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. The transfers of receivables to IPL Funding are recorded as sales however no gain or loss is recorded on the sale.

Under the receivables purchase facility, if IPL fails to maintain certain financial covenants regarding interest coverage and debt-to-capital ratios, it would constitute a termination event. IPL is 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 new receivables and cause all proceeds of the purchased receivables 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 receivables (currently $50 million).

CAUTIONARY STATEMENTS AND RISK FACTORS

Certain statements contained in this Form 10-K/A are forward-looking statements as that term is defined in the Private Securities Litigation Reform Act of 1995. These forward-looking statements speak only as of the date hereof. Forward-looking statements can be identified by the use of forward-looking terminology such as believe, expects, may, intends, will, should or anticipates or the negative forms or other va these terms or comparable terminology, or by discussions of strategy. The results described in forward-looking statements may not be achieved. Forward-looking statements are subject to risks, uncertainties and other factors, which could cause actual results to differ materially from future results expressed or implied by such forward-looking statements.

We wish to caution readers that the following important factors, among others, relate to areas affecting us, which involve risk and uncertainty. You should consider these factors when reviewing our business. We rely on these factors when issuing any forward-looking statements. These factors could affect our actual results and cause our actual results to differ materially from our current expectations expressed in any forward-looking statements we make. Some or all of these factors may apply to our businesses as currently maintained or to be maintained.

- Our inability to raise capital on favorable terms, to refinance existing corporate or subsidiary indebtedness or to fund operations, future acquisitions, construction of Greenfield plants and other capital commitments, particularly during times of uncertainty in the capital markets and in those areas of the world where the capital and bank markets are underdeveloped.

- Temporary or prolonged over/under supply in key markets and changes in the economic and electricity consumption growth rates in the United States and non-U.S. countries.

- Changes in operation and availability of our generating plants (including wholly and partially owned facilities) compared to our historical performance; changes in our historical operating cost structure, including but not limited to those costs associated with fuel, operations, supplies, raw materials, maintenance and repair, people, environmental compliance, including the costs of required emission offsets, purchase and transmission of electricity and insurance; changes in the availability of fuel, supplies, raw materials, emission offsets, transmission access and insurance; changes or increases in planned or unplanned capital expenditures or other maintenance activities, including but not limited to expenditures relating to environmental emission equipment, changes in law or regulation, sudden mechanical failure, or acts of God.

- Ability of our power generation plants to maintain or renew power supply contracts to effectively utilize our facilities productive capacity and recover increased costs. Ability of our merchant plants to effectively market power in light of increasing competitive activity.

- Adverse weather conditions and the specific needs of each plant to perform unanticipated facility maintenance or repairs or outages (including annual or multi-year), or to install pollution control equipment or other environmental emission equipment.

- Changes in the cost structure of our distribution businesses, including unexpected increases in planned or unplanned capital expenditures or other maintenance activities; our inability to predict, influence or respond appropriately to changes in law or regulatory schemes, including our inability to obtain expected or contracted changes in electricity tariff rates or tariff adjustments for increased expenses. Changes in the application or interpretation of regulatory provisions in certain jurisdictions where our electricity tariffs are subject to regulatory review or approval, 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; changes in state or federal regulatory provisions; our inability to obtain redress from regulatory authorities; regulatory bodies unwillingness to take required actions, retrenchment or delay in taking action.

- Changes or increases in taxes on property, plant, equipment, emissions, gross receipts, income or other aspects of our business or operations; reversal of our tax positions by the relevant tax authorities.

- Changes in the underlying foreign currency exchange rates or unexpected changes in those rates or adjustments; our ability or inability to obtain, or hedge against movements in an economical manner of foreign currency; foreign currency exchange rates and fluctuations in those rates.

- Conditions or restrictions impairing repatriation of earnings or other cash flow.

- Local inflation and monetary fluctuations; import and other charges or taxes.

- The economic, political and military conditions causing property, interruption of business and expropriation risks; changes in trade, monetary and fiscal policies, laws and regulations; unwillingness of governments to honor contracts or other activities of governments, agencies, government-owned entities and similar organizations; development progress and other social and economic conditions; inability to obtain access to fair and equitable political, regulatory, administrative and legal systems, enforcement of judgments or a just result; nationalizations and unstable governments and legal systems, and intergovernmental disputes.

- The effects of a worldwide depression, recession or economic downturn; prolonged economic crisis in countries, states or regions where we conduct, or are seeking to conduct, our business; political, economic and market instability related to or resulting from economic crisis and the related collateral effects, including, but not limited to, riots, looting, destruction of property, terrorism and civil war.

- Our inability to protect our rights and assets due to dysfunctional, corrupt or ineffective administrative or legal systems.

- Changes in the amount of, and rate of growth in, our corporate and business development office expenses, the impact of our ongoing evaluation of our development costs, business strategies and asset valuations, including, but not limited to, the effect of our failure to successfully complete certain acquisition, construction or development projects.

- Legislation intended to promote competition in U.S. and non-U.S. electricity markets, including the effects of such legislation upon existing contracts, such as:

- legislation currently receiving consideration in the United States Congress which would repeal PUHCA and partially repeal PURPA or the obligation of utilities to purchase electricity from qualifying facilities;

- changes in regulatory rule-making by the U.S. Securities and Exchange Commission, the U.S. Federal Energy Regulatory Commission or other regulatory bodies;

- changes in energy taxes;

- new legislative or regulatory initiatives in U.S. and non-U.S. countries; and

- changes in national, state or local energy, environmental, safety, tax and other laws and regulations or interpretations thereof applicable to us or our operations.

- A reversal or continued slowdown of the trend toward electricity industry deregulation in the various markets in which we are currently conducting or seeking to conduct business.

- Any significant customer or any of its subsidiaries   failure to fulfill its contractual payment obligations presently or in the future, either because such customer is financially unable to fulfill such contractual obligation or otherwise refuses to do so.

- Successful and timely completion of:

- the respective construction of each of our electric generating projects now under construction and those projects yet to begin construction,

- capital improvements to our existing facilities, and

- the favorable resolution of pending or potential disputes regarding the construction of our projects.

- Successful and timely completion of pending and future acquisitions; conducting appropriate due diligence; and accurate assumptions regarding the performance of countries, markets, and models.

- The lack of portability of products and services produced by our power plants and distribution companies beyond the local markets where such products or services are produced; our failure to include dollar indexation and other protective provisions in contracts or through third party hedging mechanisms, or contracting parties refusal to abide by such provisions when included.

- Changes and volatility in inflation, fuel, electricity and other commodity prices in U.S. and non-U.S. markets; conditions in financial markets, including fluctuations in interest rates and the availability of capital.

- The costs and other effects of legal and administrative cases, arbitrations or proceedings, settlements and investigations, claims (including insurance claims for losses suffered).

- Environmental remediations and changes in those items, developments or assertions by or against us; changes in or new environmental restrictions which may force us to incur significant expenses or exceed our estimates.

- The effect of new, or changes in, accounting policies and practices and the application of such policies and practices.

- The failure of any significant manufacturer of parts for our subsidiaries facilities or any significant provider of construction services to our subsidiaries to fulfill its contractual obligations presently or in the future, either because such manufacturer or service provider is financially unable to fulfill such obligations or otherwise refuses to do so.

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/Venezuelan bolivar exchange rate and the U.S. dollar/Argentine peso 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 forward and swap agreements, 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 competitive supply 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 involves 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. 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.

During the year ended December 31, 2004, our average daily VaR for interest rate-sensitive instruments was $110 million. The daily VaR for interest rate-sensitive instruments was highest at the end of the second quarter, and equaled $125 million. The daily VaR for interest rate-sensitive instruments was lowest at the end of the fourth quarter, and equaled $91 million. These amounts include the financial instruments that serve as hedges and the underlying hedged items.

During the year ended December 31, 2004, our average daily VaR for foreign exchange rate-sensitive instruments was $27 million. The daily VaR for foreign exchange rate-sensitive instruments was highest at the end of the fourth quarter, and equaled $39 million. The daily VaR for foreign exchange rate-sensitive instruments was lowest at the end of the first quarter, and equaled $20 million. These amounts include the financial instruments that serve as hedges and the underlying hedged items.

During the year ended December 31, 2004, our average daily VaR for commodity price-sensitive instruments was $9 million. The daily VaR for commodity price-sensitive instruments was highest at the end of the fourth quarter, and equaled $10 million. The daily VaR for commodity price-sensitive instruments was lowest at the end of the third quarter, and equaled $7 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. The table below details the average daily VaR for AES foreign exchange, interest rates and commodity activities over the past three years. Since 2002 AES has seen a substantial decline in foreign exchange volatility, particularly the Brazilian real and Argentine peso, which led to a decrease in VaR from $45 million in 2002 to $27 million in 2004. In regards to interest rates, AES has made efforts during 2004 to increase the percentage of its portfolio of fixed versus floating rate debt. This has in part led to the increase in VaR from $99 million in 2003 to $110 million in 2004. The AES commodity VaR is reported for financially settled derivative products at its competitive supply business in New York State. From 2003 to 2004 there has been an increase in term and magnitude of hedging activity which has led to the increase in the daily VaR from $6 million to $9 million.

Average Daily VaR	**2004**	**2003**	**2002**
	(in millions)		
Foreign Exchange	$ 27	$ 34	$ 45
Interest Rate	$ 110	$ 99	$ 72
Commodity	$ 9	$ 6	$ 5

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, 2004 and 2003, 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, 2004. Our audits also included the financial statement schedules listed on pages S-1 to S-9 of the Company s annual report on Form 10-K. 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, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, 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 changed its method of accounting for certain contracts for the purchase or sale of electricity effective October 1, 2003 to conform to Derivative Implementation Group Issue C-20. As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for certain contracts for the purchase or sale of electricity effective April 1, 2003 to conform to Derivative Implementation Group Issue C-15. As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for stock-based compensation effective January 1, 2003, to conform to the fair value recognition provision of Statement of Financial Accounting Standard No. 123, as amended by Statement of Financial Accounting Standard No. 148, prospectively to all employee awards granted, modified or settled after January 1, 2003. As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations effective January 1, 2003 to conform to Statement of Financial Accounting Standard No. 143. As discussed in Note 7 to the consolidated financial statements, the Company changed its method of accounting for goodwill and other intangible assets effective January 1, 2002 to conform to Statement of Financial Accounting Standard No. 142.

As discussed in Note 1 to the consolidated financial statements, the accompanying 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, 2004, 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 March 29, 2005 (January 18, 2006, as to the effect of the material weaknesses as described in Management s Report on Internal Controls over Financial Reporting, as restated) 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.

/s/ Deloitte & Touche LLP

McLean, VA
March 29, 2005 (January 18, 2006, as to the effect of the restatement described in Note 1)

THE AES CORPORATION
CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2004 AND 2003

	2004 (Restated)*	2003 (Restated)*
	(Amounts in millions, except (shares and par value)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 1,281	$ 1,663
Restricted cash	395	288
Short-term investments	268	264
Accounts receivable, net of reserves of $303 and $291 respectively	1,575	1,361
Inventory	418	376
Receivable from affiliates	8	3
Deferred income taxes current	218	198
Prepaid expenses	87	62
Other current assets	736	517
Current assets of held for sale and discontinued businesses		205
Total current assets	4,986	4,937
Property, Plant and Equipment:		
Land	788	733
Electric generation and distribution assets	21,729	20,221
Accumulated depreciation	(5,259)	(4,462)
Construction in progress	919	1,278
Property, plant and equipment, net	18,177	17,770
Other Assets:		
Deferred financing costs, net	343	302
Investment in and advances to affiliates	655	648
Debt service reserves and other deposits	737	617
Goodwill, net	1,419	1,421
Deferred income taxes noncurrent	774	809
Long-term assets of held for sale and discontinued businesses		657
Other assets	1,832	1,976
Total other assets	5,760	6,430
Total Assets	$ 28,923	$ 29,137
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 1,142	$ 1,224
Accrued interest	335	561
Accrued and other liabilities	1,656	1,248
Current liabilities of held for sale and discontinued businesses		687
Recourse debt-current portion	142	77
Non-recourse debt-current portion	1,619	2,769
Total current liabilities	4,894	6,566
Long-term liabilities:		
Non-recourse debt	11,817	10,930
Recourse debt	5,010	5,862
Deferred income taxes-noncurrent	685	673
Long-term liabilities of held for sale and discontinued businesses		95
Pension liabilities and other post-retirement liabilities	891	937
Other long-term liabilities	3,375	3,181
Total long-term liabilities	21,778	21,678
Minority Interest, including discontinued businesses of $0 and $12	1,279	961
Commitments and Contingent Liabilities (see Notes 10 and 11)		
Stockholders equity (deficit):		
Common stock ($.01 par value, 1,200,000,000 shares authorized; 650,093,402 and 625,590,867 shares issued and outstanding at December 31, 2004 and 2003, respectively)	7	6
Additional paid-in capital	6,423	5,739
Accumulated deficit	(1,815)	(2,107)
Accumulated other comprehensive loss	(3,643)	(3,706)
Total stockholders equity (deficit)	972	(68)
Total Liabilities and Stockholders Equity	$ 28,923	$ 29,137

* See Note 1

See notes to consolidated financial statements

THE AES CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

	2004 (Restated)* (Amounts in millions, except per share amounts)	2003 (Restated)*	2002 (Restated)*
Revenues			
Regulated	$ 4,897	$ 4,425	$ 4,015
Non-Regulated	4,566	3,988	3,362
Total revenues	9,463	8,413	7,377
Cost of Sales			
Regulated	(3,781)	(3,449)	(3,292)
Non-Regulated	(2,900)	(2,505)	(2,117)
Total cost of sales	(6,681)	(5,954)	(5,409)
Gross margin	2,782	2,459	1,968
General and administrative expenses	(182)	(157)	(112)
Interest expense	(1,941)	(1,986)	(1,792)
Interest income	282	280	259
Other income	163	171	144
Other expense	(151)	(106)	(87)
Loss on sale of investments and asset impairment expense	(45)	(201)	(473)
Goodwill impairment expense		(11)	(738)
Foreign currency transaction (losses) gains on net monetary position	(147)	99	(644)
Equity in earnings (loss) of affiliates	70	94	(203)
INCOME (LOSS) BEFORE INCOME TAXES AND MINORITY INTEREST	831	642	(1,678)
Income tax expense	(375)	(211)	(461)
Minority interest (expense) income	(198)	(120)	75
INCOME (LOSS) FROM CONTINUING OPERATIONS	258	311	(2,064)
Income (loss) from operations of discontinued businesses (net of income tax benefit of $36, $75 and $415)	34	(787)	(1,561)
INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	292	(476)	(3,625)
Cumulative effect of accounting change (net of income tax expense (benefit) of $, $22 and $(58))		41	(376)
Net income (loss)	$ 292	$ (435)	$ (4,001)
BASIC EARNINGS (LOSS) PER SHARE:			
Income (loss) from continuing operations	$ 0.40	$ 0.52	$ (3.83)
Discontinued operations	0.06	(1.32)	(2.89)
Cumulative effect of accounting change		0.07	(0.70)
BASIC EARNINGS (LOSS) PER SHARE:	$ 0.46	$ (0.73)	$ (7.42)
DILUTED EARNINGS (LOSS) PER SHARE:			
Income (loss) from continuing operations	$ 0.40	$ 0.52	$ (3.83)
Discontinued operations	0.05	(1.32)	(2.89)
Cumulative effect of accounting change		0.07	(0.70)
DILUTED EARNINGS (LOSS) PER SHARE:	$ 0.45	$ (0.73)	$ (7.42)

* See Note 1

See notes to consolidated financial statements

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THE AES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

	2004 (Restated)*	2003 (Restated)*	2002 (Restated)*
	(Amounts in millions)		
OPERATING ACTIVITIES:			
Net income (loss)	$ 292	$ (435)	$ (4,001)
Adjustments to net income (loss):			
Depreciation and amortization of intangible assets	801	755	816
Loss from sale of investments and goodwill and asset impairment expense	45	215	1,211
(Gain) loss on disposal and impairment write-down associated with discontinued operations	(98)	686	1,906
Provision for deferred taxes	200	(89)	(152)
Minority interest expense (earnings)	198	120	(75)
Other	296	(123)	1,514
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(128)	(101)	128
(Increase) decrease in inventory	(33)	(2)	129
Decrease (increase) in prepaid expenses and other current assets	7	180	(216)
Increase in accounts payable and accrued liabilities	226	697	475
Other assets and liabilities	(235)	(261)	(200)
Net cash provided by operating activities	1,571	1,642	1,535
INVESTING ACTIVITIES:			
Property additions	(892)	(1,228)	(2,116)
Acquisitions net of cash acquired			(35)
Proceeds from the sales of assets	63	1,086	375
Sale of short-term investments	1,335	1,855	1,478
Purchase of short-term investments	(1,319)	(1,857)	(1,537)
(Increase) decrease in restricted cash	(32)	(214)	25
(Increase) decrease in debt service reserves and other assets	(151)	(28)	23
Other investing	(29)	(14)	203
Net cash used in investing activities	(1,025)	(400)	(1,584)
FINANCING ACTIVITIES:			
(Repayments) borrowings under the revolving credit facilities, net		(228)	158
Issuance of recourse debt	491	2,503	1,188
Issuance of non-recourse debt and other coupon bearing securities	2,449	2,111	2,293
Repayments of recourse debt	(1,140)	(2,877)	(829)
Repayments of non-recourse debt and other coupon bearing securities	(2,534)	(2,039)	(2,560)
Payments for deferred financing costs	(109)	(146)	(67)
Distributions to minority interests	(139)	(50)	(101)
Contributions from minority interests	28	38	85
Issuance of common stock	16	337	
Other financing	2	(2)	
Net cash (used in) provided by financing activities	(936)	(353)	167
Effect of exchange rate changes on cash	8	34	(55)
Total (decrease) increase in cash and cash equivalents	(382)	923	63
Cash and cash equivalents, beginning	1,663	740	677
Cash and cash equivalents, ending	$ 1,281	$ 1,663	$ 740
SUPPLEMENTAL DISCLOSURES:			
Cash payments for interest-net of amounts capitalized	$ 1,759	$ 1,827	$ 2,007
Cash payments for income taxes-net of refunds	197	177	(30)
SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES:			
Common stock issued for debt retirement	168	48	73
Liabilities relieved due to sale of assets		1,296	
Liabilities consolidated in Eletropaulo transaction			4,907
Brasiliana Energia debt exchange	773		

* See Note 1

See notes to consolidated financial statements

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THE AES CORPORATION
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY (DEFICIT)
YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

	Common Stock Shares	Amount	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Loss	Comprehensive (Loss) Income
	(Amounts in Millions)					
Balance at January 1, 2002, as reported	533.2	$ 5	$ 5,225	$ 2,774	$ (2,501)	
Effect of restatement*				(445)	96	
Balance at January 1, 2002 (Restated)*	533.2	5	5,225	2,329	(2,405)	
Net loss (Restated)*				(4,001)		$(4,001)
Foreign currency translation adjustment (net of reclassification to earnings of $65 for the sale or write off of investments in foreign entities, no income tax effect) (Restated)*					(1,358)	(1,358)
Realized losses on marketable securities (no income tax effect)					48	48
Minimum pension liability adjustment (net of income tax benefit of $274) (Restated)*					(508)	(508)
Change in derivative fair value (including a reclassification to earnings of $(106), net of tax, and an income tax benefit of $63) (Restated)*					(280)	(280)
Comprehensive loss (Restated)*						$ (6,099)
Issuance of common stock in exchange for cancellation of debt	21.6	1	73			
Issuance of common stock under benefit plans and exercise of stock options and warrants (Restated)*	3.1		16			
Balance at December 31, 2002 (Restated)*	557.9	6	5,314	(1,672)	(4,503)	
Net loss (Restated)*				(435)		(435)
Foreign currency translation adjustment (net of reclassification to earnings of $114 for the sale or write off of investments in foreign entities, no income tax effect) (Restated)*					370	370
Minimum pension liability adjustment (net of income tax expense of $110) (Restated)*					286	286
Change in derivative fair value (including a reclassification to earnings of $(126) million, net of tax, and an income tax expense of $17) (Restated)*					141	141
Comprehensive income (Restated)*						$ 362
Issuance of common stock through public offering	49.5		334			
Issuance of common stock in exchange for cancellation of debt	12.2		63			
Issuance of common stock under benefit plans and exercise of stock options and warrants	6.0		19			
Stock option expense			9			
Balance at December 31, 2003 (Restated)*	625.6	6	5,739	(2,107)	(3,706)	
Net income (Restated)*				292		292
Subsidiary sale of stock (Restated)*			462			
Foreign currency translation adjustment (net of reclassification to earnings of $(46) for the sale or write off of investments in foreign entities, no income tax effect) (Restated)*					113	113
Minimum pension liability adjustment (net of income tax expense of $4)					22	22
Change in derivative fair value (including a reclassification to earnings of $(122) million, net of tax, and an income tax benefit of $41) (Restated)*					(72)	(72)
Comprehensive income (Restated)*						$ 355
Issuance of common stock in exchange for cancellation of debt	19.7	1	168			
Issuance of common stock under benefit plans and exercise of stock options and warrants (Restated)*	4.8		34			
Stock compensation			20			
Balance at December 31, 2004 (Restated)*	650.1	$ 7	$ 6,423	$ (1,815)	$ (3,643)	

*   See Note 1

See notes to consolidated financial statements

THE AES CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2004, 2003 AND 2002

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. In all cases, AES holds a majority ownership interest in those variable interest entities that have been consolidated. Investments in which the Company has the ability to exercise significant influence but not control are accounted for using the equity method. All 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.

RECLASSIFICATIONS **Certain** reclassifications have been made to prior-period amounts to conform to the 2004 presentation of discontinued operations.

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.

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.

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 collectability 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

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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 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.

GOODWILL In accordance with Statement of Financial Accounting Standards (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.

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 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, we made our best estimate of fair value using valuation methods based on the most current information at that time. 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. 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 Effective January 1, 2003, the Company adopted SFAS No. 143, Accounting for Asset Retirement Obligations. 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 include primarily active ash landfills, water treatment basins and the removal or dismantlement of certain plant and equipment. As of December 31, 2004 and 2003, the Company had recorded liabilities of approximately $26 million and $29 million, respectively, related to asset retirement obligations. There are no assets that are legally restricted for purposes of settling asset retirement obligations. Upon adoption of SFAS No. 143, the Company recorded an additional liability of approximately $13 million, a net asset of approximately $9 million, and a cumulative effect of a change in accounting principle of approximately $2 million, after income taxes. Amounts recorded related to asset retirement obligations during the years ended December 31, 2004 and 2003 were as follows (in millions):

	2004	2003
Balance at January 1	$ 29	$ 15
Additional liability recorded from cumulative effect of accounting change		13
Accretion expense	2	2
Change in the timing of estimated cash flows	(6)	(1)
Translation adjustments	1	
Balance at December 31	$ 26	$ 29

Proforma net loss and loss per share have not been presented for the year ended December 31, 2002 because the proforma application of SFAS No. 143 to the prior period would have resulted in proforma net loss and loss per share not materially different from the actual amounts reported for that period in the accompanying consolidated statement of operations. Had SFAS No. 143 been applied during all periods presented, the asset retirement obligation at January 1, 2002 and December 31, 2002 would have been approximately $23 million and $28 million, respectively.

GUARANTOR ACCOUNTING Pursuant to the Financial Accounting Standards Board Interpretation No. (FIN) 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 revenues of the large utilities and growth distribution segments are classified as regulated. 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 contract generation and competitive supply segments 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.

Within the Company s regulated businesses, sales of purchased power were $1.4 billion, $1.3 billion and $1.3 billion for the years ended December 31, 2004, 2003 and 2002, respectively. The related power purchased by the regulated businesses was approximately $800 million, $900 million and $700 million for the years ended December 31, 2004, 2003 and 2002, respectively. The Company s non-regulated businesses consist primarily of generation businesses, and therefore, do not generally purchase power for resale.

GENERAL AND ADMINISTRATIVE EXPENSES The Company classifies corporate and business development expenses, including corporate depreciation and amortization, as General and Administrative.

DEFERRED REGULATORY ASSETS AND LIABILITIES The Company accounts for 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 for previous collections for costs that are not likely to be incurred. 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. The Company does not enter into derivative transactions for trading purposes. Under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as

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amended, the Company recognizes all derivatives as either assets or liabilities in the balance sheet and measures those instruments at fair value. 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, cash flow hedges and hedges of net investment in foreign operations. For all hedge contracts, the Company provides formal documentation of the hedge and effectiveness testing in accordance with SFAS No. 133.

In April 2002, Derivatives Implementation Group (DIG) Issue C-15, related to contracts involving the purchase or sale of electricity became effective. Contracts for the purchase or sale of electricity, both forward and option contracts, including capacity contracts, may qualify for the normal purchases and sales exemption and are not required to be accounted for as derivatives under SFAS No. 133. In order for contracts to qualify for this exemption, they must meet certain criteria, which include the requirement for physical delivery of the electricity to be purchased or sold under the contract only in the normal course of business. However, contracts that have a price based on an underlying index that is not clearly and closely related to the electricity being sold or purchased, or that are denominated in a currency that is foreign to the buyer or seller, are not considered normal purchases and normal sales and are required to be accounted for as derivatives under SFAS No. 133.

The Company has two contracts that previously qualified for the normal purchases and normal sales exemption of SFAS No. 133, but no longer qualify for this exemption due to the effectiveness of DIG Issue C-15 on April 1, 2002. Accordingly, these contracts were required to be accounted for as derivatives at fair value. The contracts were valued as of April 1, 2002, and an asset and a corresponding gain of $127 million, net of income taxes, were recorded as a cumulative effect of a change in accounting principle. The contracts were subsequently accounted for at fair value as derivatives. The contract valuations were performed using then current forward electricity and gas price quotes and current market data for other contract variables. The forward curves used to value the contracts include certain assumptions, including projections of future electricity and gas prices in periods where future prices are not quoted.

In June 2003, the FASB issued DIG Issue C-20, that superceded DIG Issue C-11 and provided additional guidance related to the impact of certain price adjustment features on the ability of a contract to qualify for the normal purchases and sales exemption. In order for contracts to qualify for the exemption, they must first meet certain criteria, including requirements that the underlying price adjustment may not be considered extraneous and that the magnitude and direction of the impact of the price adjustment is consistent with the relevancy of the underlying. Additionally, there are restrictions on certain contracts with an underlying associated with currency exchange rates qualifying for the exemption. Under the transition provisions of DIG Issue C-20, the Company was required to record a cumulative effect of change in accounting principle adjustment of $43 million, net of income taxes on October 1, 2003 for the fair value of a power sales contract. This contract subsequently qualified for the normal purchases and sales exemption and the contract s carrying value is being amortized on a straight-line basis over the remaining life of the contract.

STOCK OPTIONS Prior to 2003, the Company accounted for stock-based compensation plans under the recognition and measurement provisions of APB Opinion No. 25, Accounting for Stock Issued to Employees , and related interpretations. Effective January 1, 2003, the Company adopted 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. Prior to 2002, awards under the Company s plans generally vested over two years. Therefore, the cost related to stock-based employee compensation included in the determination of net income for the years ended December 31, 2004 and 2003, is less than what would have been recognized if the fair value based method had been applied to all awards since the original effective date of SFAS No. 123. However, if SFAS No. 123 had been applied to all grants since the original effective date, the impact on net income would have been minimal since there were very few grants that would have had expense carried over to 2004 and 2003.

No stock-based employee compensation cost is reflected in the net loss for the year ended December 31, 2002, as all options granted under the plans had an exercise price equal to the market value of the underlying common stock on the date of grant.

The following table illustrates the effect on net income and earnings per share if the fair value based method had been applied to all outstanding and unvested awards for the year ended December 31, 2002 (in millions, except per share amounts):

	2002
Net loss, as reported	$ (4,001)
Add: Stock-based employee compensation expense included in reported net loss, net of related tax effects	
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(148)
Proforma net (loss) income	$ (4,149)
Earnings (loss) per share:	
Basic as reported	$ (7.42)
Basic proforma	$ (7.70)
Diluted as reported	$ (7.42)
Diluted proforma	$ (7.70)

SALES OF STOCK BY A SUBSIDIARY Sales of stock by a subsidiary of the Company are accounted for as capital transactions pursuant to the Securities and Exchange Commission s Staff Accounting Bulletin No. 51 Accounting for Sales of Stock by a Subsidiary (SAB 51).

VARIABLE INTEREST ENTITIES In January 2003, the FASB issued FIN 46 which addresses consolidation by business enterprises of variable interest entities (VIE). The primary objective of FIN 46 is to provide guidance on the identification of and financial reporting for, entities over which control is achieved through means other than voting rights; such entities are known as VIEs. FIN 46 requires an enterprise to consolidate a VIE if that enterprise has a variable interest that will absorb a majority of the entity s expected losses if they occur, receive a majority of the entity s expected residual returns if they occur, or both. An enterprise shall consider the rights and obligations conveyed by its variable interests in making this determination.

On December 24, 2003, the FASB issued Financial Interpretation No. 46 (Revised 2003) Consolidation of Variable Interest Entities (FIN 46(R) or Revised Interpretation), which partially deferred the effective date of FIN 46 for certain entities and makes other changes to FIN 46, including a more complete definition of variable interest, and an exemption for many entities defined as businesses.

The Company applied FIN 46 in its financial statements relating to its interest in variable interest entities or potential variable interest entities as of December 31, 2003, and applied FIN 46(R) as of March 31, 2004. Application of FIN 46 as of December 31, 2003 resulted in the special purpose business trusts that issued Term Convertible Preferred Securities no longer being consolidated (see Note 8). The application of FIN 46(R) did not have any additional impact on the Company s consolidated financial statements.

NEW ACCOUNTING PRONOUNCEMENTS

Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003. In May 2004, the FASB issued FASB Staff Position (FSP) 106-2, which provides guidance on the accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) for employers that sponsor postretirement health care plans that provide prescription drug benefits. One of the Company s subsidiaries maintains a retiree health benefit plan that currently includes a prescription drug benefit that is provided to retired employees. The enactment of the Act did not have a significant effect on the subsidiaries retirement plan. The accumulated pension benefit obligation and net periodic postretirement benefit costs associated with this retiree health plan currently reflect the effects of the Act. The effects of the Act, which were not material, were incorporated into the November 30, 2004 measurement of plan obligations as required by FSP 106-2.

Share-Based Payment. In December 2004, the FASB issued a revised SFAS No.123 (SFAS No. 123R), Share-Based Payment, which is a revision of SFAS No. 123. SFAS No. 123R eliminates the intrinsic value method under APB 25 as an alternative method of accounting for stock-based awards by requiring that all share-based payments to employees, including grants of stock options for all outstanding years be recognized in the financial statements based on their fair values. It also revises the fair-value based method of accounting for share-based payment liabilities, forfeitures and modifications of stock-based awards and clarifies SFAS No. 123 s guidance related to measurement of fair value, classifying an award as equity or as a liability and attributing compensation to reporting periods. In addition, SFAS No. 123R amends SFAS No. 95, Statement of Cash Flows, to require that excess tax benefits be reported as a financing cash flow rather than as an operating cash flow.

The Company is required to adopt SFAS No. 123R for the interim period beginning July 1, 2005 using a modified version of prospective application. The Company may apply a modified retrospective application to periods before the required effective date. The Company plans to adopt SFAS No. 123R no later than July 1, 2005, but has not determined what method it will use. Management is currently evaluating the effect of adoption of SFAS No. 123R, but does not expect the adoption to have a material effect on the Company s financial condition, results of operations or cash flows, as the Company had previously adopted income statement treatment for compensation related to share-based payments under SFAS No. 123.

RESTATEMENT OF CONSOLIDATED FINANCIAL STATEMENTS

In our previously filed Form 10-K, for the year ended December 31, 2004, management reported that a material weakness existed in its internal controls over financial reporting related to accounting for income taxes. Specifically, the Company lacked effective controls for the proper reconciliation of the components of its foreign subsidiaries income tax assets and liabilities to related consolidated balance sheet accounts.

After examining certain historical purchase transactions from 1999 2002 and reviewing the reconciliations of detailed historical income tax return records to reported book/income tax differences, various accounting errors were identified. As a result of these initial findings, on July 27, 2005 the Company announced that it would restate its previously filed financial statements. Management also expanded the scope of the review to include the composition of other material current and deferred income tax related balances including those recorded by or, on behalf of, our domestic subsidiaries and the parent company. As a result of this expanded review, additional non-tax items also were identified and corrected. A discussion of both income tax and non-tax adjustments follows.

Income Tax Adjustments

The errors identified from the income tax review can be categorized into three types of deferred tax issues. Details regarding material findings associated with each issue are provided below:

1. Deferred income tax adjustments associated with foreign acquisitions and restructurings

La Electricidad de Caracas (EDC)

The most significant deferred income tax restatement adjustment related to the purchase of a majority interest in EDC, a private integrated utility in Venezuela in June, 2000. At that time, a deferred income tax liability was recorded representing the difference between the non-inflation indexed income tax basis and the resulting adjusted purchase basis (assigned carrying value) of fixed assets. However, Venezuelan income tax provisions allow for the indexing of EDC s non-monetary assets and equity, as a result of inflation. This indexing created an additional layer of tax basis that should have been included as part of the acquisition income tax basis at the time of the acquisition.

The impact of correcting the income tax basis used to calculate the original temporary difference was an increase of $668 million in the original deferred income tax asset. In addition, several other purchase accounting adjustments were recorded to correctly account for the treatment of deferred charges and the fair value applied to an equity investment held by EDC at the time of acquisition. The recording of the deferred income tax asset related to indexation and the other noted adjustments affected the allocation of the excess fair value over cost (commonly referred to as negative goodwill) to non-monetary assets.

The net result of these adjustments decreased fixed assets in 2000 by $572 million and decreased other assets by $85 million. The reduction in depreciation and amortization expense was $24 million for the year ended December 31, 2002, $24 million for the year ended December 31, 2003 and $23 million for the year ended December 31, 2004.

Eletropaulo Metropolitana Electricidade de Sao Paulo S.A. (Eletropaulo)

At the time of the acquisition of Eletropaulo, a regulated utility located in Brazil, the Company did not record certain deferred income taxes on the difference between the tax basis of land and the related book basis which was adjusted to fair value under acquisition accounting guidelines. The correction of this error resulted in the recording of additional deferred income tax liabilities of $101 million at the initial date of consolidation in February 2002. This increase in deferred income tax liability increased the original goodwill calculated as the excess purchase price over the fair value of assets and liabilities. As a further result, this adjustment also increased goodwill impairment expense subsequently recognized in 2002 by $71 million.

Brasiliana Energia, S.A. (Brasiliana)

In January, 2004 the Company entered into a debt restructuring transaction with the Brazilian National Bank for Economic and Social Development (BNDES), whereby BNDES received a 54% economic interest in our Brazil distribution business and two generating facilities in exchange for the cancellation of $863 million of debt and accrued interest owed by AES Elpa and AES Transgas, holding companies for the Brazilian operations. After the Company made a cash payment of $90 million, the remaining indebtedness of $510 million, was re-profiled at a 9% stated interest rate with extended maturities. This exchange was accounted for as a modification of debt. The terms of the agreement state that penalty interest as of December 31, 2004 of $194 million would be cancelled in the future ratably as the principal of the new $510 million debentures are paid within the stated timeframes. This treatment gave rise to a deferred income tax liability. As a result of the income tax review, it was determined that a deferred income tax liability should have been recorded for $194 million of penalty interest anticipated to be forgiven in the future. To correct this error, the additional deferred income tax liability was recorded as part of the stock issued for debt restructuring transaction, with the following impacts:

- A deferred income tax liability of $73 million at Brasiliana (the new parent company of the restructured entities), was recorded as of January, 2004. This deferred liability is also subject to foreign currency remeasurement in each subsequent reporting period.

- Debt modification calculations were adjusted to include the fair value of the increased income tax expense due to the forgiveness of debt compared to the book value of debt remaining. The resulting impact reduced the debt discount from $26 million to $20 million and decreased the effective interest rate from the originally calculated amount of 9.67% to 9.32%. This adjustment did not change our conclusion regarding the accounting treatment of the transaction as a modification of debt.

These adjustments also impacted the amounts recorded to reflect the BNDES debt restructuring described above. This impact is described below in the Other Non Income Tax Adjustments section.

Other Acquisition Related Income Tax Adjustments

As a result of the comprehensive review of income tax accounting, certain other adjustments were made to correct errors identified at other subsidiaries, primarily related to recording of deferred income taxes arising from the step up of acquired assets to fair value and/or from other purchase accounting items. These adjustments increased or decreased fixed assets or concession assets and as a result impacted depreciation or amortization charges recorded within the Company s statements of operations. The impact on depreciation expense from these adjustments was an increase of $3 million for the year ended December 31, 2002, an increase of $3 million for the year ended December 31, 2003 and a decrease of $5 million for the year ended December 31, 2004. The impact on amortization expense was a decrease of $1 million for the year ended December 31, 2002, a decrease of $1 million for the year ended December 31, 2003 and a decrease of $5 million for the year ended December 31, 2004.

2. Foreign currency remeasurement of deferred income tax balances where the U.S. dollar is the functional currency at certain subsidiaries

The functional currency for certain of the Company s foreign subsidiaries is the U.S. dollar. After reviewing the income tax balances for certain of the Company s U.S. dollar entities in Venezuela, Brazil, Chile, Colombia, Dominican Republic, Argentina and Mexico, the Company discovered that deferred income taxes were remeasured from local currency to the U.S. dollar using the historical exchange rate versus the current exchange rate as prescribed by Statement of Financial Accounting Standard (SFAS) No. 52, Foreign Currency Translation and SFAS No. 109, Accounting for Income Taxes, starting in the year of acquisition or formation. In addition, as noted above, certain additional deferred tax amounts were recorded in these entities, which also required remeasurement the largest of which was the additional deferred tax asset related to the EDC purchase accounting indexation adjustment of $668 million described above.

The additional foreign currency transaction losses related to deferred taxes was $187 million for the year ended December 31, 2002, $34 million for the year ended December 31, 2003 and $38 million for the year ended December 31, 2004.

3. Reconciliation of income tax returns to U.S. GAAP income tax balances

The remediation plan involved a detailed review of current and temporary differences identified through an analysis of local income tax return filings. The completion of this review also required the Company to fully evaluate adjustments which had been previously recorded in consolidation, but which should have been recorded at a subsidiary level where the appropriate analysis of the tax jurisdiction could be made. This process led to the identification of errors that accounted for additional income tax expense entries, the major components of which are described below:

Establishment of Deferred Tax Liability for Brazilian Unrealized Foreign Currency Gains

Certain of the Company s Brazilian subsidiaries have designated the U.S. dollar as the functional currency for accounting purposes. For Brazilian tax purposes, these companies have elected to treat these exchange gains or losses as taxable or deductible only when cash payments are made. The Company did not record deferred assets or liabilities related to the unrealized gains and losses that occur on an interim basis related to its U.S. dollar denominated debt. Under U.S. GAAP, these increases/decreases in deferred liabilities/assets are permanent differences that are recorded as an adjustment to tax expense. The impact of recording these changes in deferred taxes increased income tax expense by approximately $32 million in 2004 and $4 million in 2003.

Establishment of a U.S. Liability Related to Brazilian Deferred Tax Assets

One of the Company s Brazilian subsidiaries, Sul, which has designated its functional currency as the real, has generated deferred tax assets mainly related to net operating losses, unrealized tax losses on foreign currency transactions and certain other taxable temporary differences. A restructuring transaction was undertaken in relation to this subsidiary in July 2002. At the time of this restructuring, the Company should have recorded a reduction to the deferred tax assets for the U.S. income tax liability associated with the future projected Brazilian taxable income. This reduction, along with other deferred tax impacts related to Sul being part of the Company s consolidated tax group resulted in additional tax expense of $32 million in 2004, $28 million in 2003 and $66 million in 2002.

Establishment of Other Valuation Allowances

The Company determined that certain valuation allowances should have been provided at various subsidiaries in Chile, Colombia, Brazil and Argentina related to deferred tax assets recorded primarily related to net operating loss carryforwards. Under U.S. GAAP, the Company is required to assess its ability to utilize deferred tax assets under a more likely than not standard and provide a valuation allowance to the extent the asset or any part of it does not meet this test. As part of the deferred tax review, the Company determined that these deferred tax assets were unlikely to be utilized in full or in part, based on information available in these historical periods and consequently did not meet the more likely than not standard. As a result, the Company recorded valuation allowances which resulted in additional tax expense of $18 million in 2004, a reduction of tax expense of $38 million in 2003 and additional tax expense of $79 million in 2002.

Other Tax Expense Items

The Company undertook a detailed comparison of the tax returns filed to accounting records in a majority of the countries in which we operate and identified certain other adjustments related to this reconciliation. Most significantly, these adjustments included the following:

- non-deductibility of certain holding company interest and goodwill;
- capitalized interest on tax holiday projects;
- treatment of certain foreign investment tax credits;
- reconciliation of other deferred tax balances; and
- changes in pre-tax book income related to other non-tax restatement adjustments.

The net impact of these other tax expense items resulted in additional tax expense of $23 million in 2002, $13 million in 2003 and $44 million in 2004. The cumulative impact on income tax expense, as a result of the restatement adjustments, was an increase of $168 million for the year ended December 31, 2002, an increase of $7 million for the year ended December 31, 2003 and an increase of $126 million for the year ended December 31, 2004.

Other Non-Income Tax Adjustments

Other non-income tax accounting errors were also identified as part of the Company s review of certain other historical transactions. The Company has concluded that the reasons for these errors primarily related to the lack of sufficient control and documentation procedures in 2002 and prior years related to certain consolidation and foreign currency translation processes. Significant non-income tax errors are described below:

AES SONEL

AES acquired 56% of SONEL located in Cameroon in July, 2001. Since that time, AES SONEL experienced a high degree of turnover of its senior accounting personnel. SONEL s accounting systems required a significant degree of manual intervention including the conversion of local GAAP financial statements into U.S. GAAP.

During the Company s 2004 year-end process, the Company discovered errors in minority interest calculations that were corrected in the Company s restated financial statements as of and for the years ended December 31, 2003 and 2002 as filed with the Securities and Exchange Commission on Form 10-K

on March 30, 2005. Subsequently, as part of the Corporate process to ensure the correct communication and documentation of the correction of the initial error at the subsidiary level, a comprehensive additional review of the preparation of the U.S. GAAP financial statements was performed and the following errors were identified:

- translation errors from local currency to U.S. dollar financial statements;
- the omission of certain purchase accounting adjustments related to the final valuation of our concession assets and recording of severance provision from the U.S. GAAP financial statements; and
- incorrect treatment related to the accounting for dividends.

The net impact of the adjustments as of December 31, 2004 resulted primarily in a reduction of intangible assets of $39 million and an increase in accumulated other comprehensive loss related to foreign currency translation of $39 million.

AES Elpa

As a result of the income tax review performed at AES Elpa, one of the Company s Brazilian holding companies, the Company identified a long-term liability which had been recorded for Brazilian GAAP but which had been omitted from U.S. GAAP financial statements at the acquisition date. The proper recording of this liability at the acquisition date would have increased the opening balance of goodwill, which was subsequently impaired and thereby written off as of the end of December, 2002. The impact of this adjustment as of December 31, 2002, increased long term liabilities by $34 million and increased goodwill impairment expense and prior retained earnings by the same combined amount. This long-term liability is accreted by an interest expense component on a monthly basis. The increase in interest expense was $5 million for the year ended December 31, 2002, $6 million for the year ended December 31, 2003 and $5 million for the year ended December 31, 2004.

AES Tiete

The Company determined that an error had been made in the initial accounting for a debt instrument which had been assumed at the date of purchase of Tiete, a generation company in Brazil in 1999. The debt requires an annual adjustment to principal based on changes in the local rate of inflation. The Company accounted for this by using estimates of future inflation over the life of the debt and amortizing these adjustments as a component of interest expense over the term of the loan. These future inflation estimates were recorded on the balance sheet as a deferred financing cost within long-term assets. Periodically, adjustments were made to these estimates when the actual annual inflation calculations were charged to the principal balance. Subsequently, it was determined that inflation changes should be calculated and adjusted on a monthly basis through interest expense based on the rate of inflation in that month, regardless of how the actual cash payment would finally be determined. The impact on interest expense was an increase of $41 million for the year ended December 31, 2002, a decrease of $7 million for the year ended December 31, 2003 and an increase of $28 million for the year ended December 31, 2004. The long term asset account was corrected to remove the estimated inflation component and resulted in a decrease in assets of $6 million as of December 31, 2002, a decrease of $21 million as of December 31, 2003 and a decrease of $42 million as of December 31, 2004.

SUL and Eletropaulo

The Company determined that an error had been made regarding the timing of the recognition of certain revenues recorded by its Brazilian utilities Eletropaulo and Sul. The tariff rates, as set by the Brazilian regulatory authority (ANEEL) provide that a percentage of a distributor s revenue is added to the consumer tariff rate in return for the Company s future spending of these amounts on capital or operating expense projects approved by ANEEL for the express purpose of improving the efficiency of the electrical system. Eletropaulo and Sul had previously recognized the revenue related to this portion of the tariff when billed, and recorded the future operating expense and capital project expenditures when incurred, since the expenditures were not considered pass through costs for purpose of a future tariff reset. However, under the guidance of SFAS 71 Accounting for the Effects of Certain Types of Regulation , Eletropaulo and Sul should have deferred this portion of revenue until such time that the related expenditures were incurred. The correction of this error resulted in a decrease in revenues of $11 million, $8 million and $8 million for the years ended December 31, 2004, 2003 and 2002, respectively. The proper recording of this liability as of the date of acquisition of Eletropaulo would have also increased the opening balance of goodwill, which was subsequently impaired and written off in December, 2002. The correction of this error, therefore, also increased goodwill impairment expense by $6 million in 2002.

Brasiliana Energia

The correction of the error related to AES Elpa described above and other adjustments prior to January 2004 which impacted the net assets of Eletropaulo, Tiete and Uruguaiana, also impacted the recording of the Brazilian debt restructuring transaction with our lender, BNDES, as described earlier. The impact on the 2004 restated financials decreased the minority interest share allocated to BNDES by $79 million and increased additional paid-in capital, a component of stockholders equity, by $79 million. The adjustment to additional paid-in capital was recorded in accordance with the Company s previously established accounting policy pertaining to gains or losses resulting from subsidiary sales of stock as permitted under SEC Staff Accounting Bulletin No. 51, Accounting for Sales of Stock by a Subsidiary.

Corporate Consolidation Accounting

During the restatement period, the Company undertook additional reviews of the consolidation process, including a review of consolidation journal entries to ascertain that appropriate supporting documentation existed and that current personnel who were performing the consolidation understood the basis for these entries. Several historical consolidation elimination adjustments were identified as errors which primarily affected deferred income taxes and other accumulated comprehensive income balances. The errors originated in years prior to 2002 and generally resulted from an inadequately controlled consolidation process including the elimination of investment accounts against subsidiary equity balances, general balancing controls related to the income statements and balance sheets submitted by our subsidiaries, and inadequate balance sheet reconciliations of consolidated deferred income tax accounts. The correcting entries resulted primarily in a decrease in deferred income tax liabilities and an increase in foreign currency translation, a component of other comprehensive income, of $294 million.

Cash Classifications

As part of an ongoing balance sheet review process, it came to the Company s attention that several of its subsidiaries incorrectly included certain short-term investments as cash and cash equivalents in the balance sheet. The restatement impact was a decrease in cash and cash equivalents and an increase in short-term investments of $127 million and $74 million as of December 31, 2004 and 2003, respectively.

Cash Flow Reclassification

The Company includes components of the cash flows for its discontinued operations within the Consolidated Statements of Cash Flows (Cash Flow Statement) in operating, investing and financing activities. A separate line entitled Decrease in cash and cash equivalents of discontinued operations and businesses held for sale was previously presented on the face of Cash Flow Statement to reconcile back to the Company s cash balance on the face of the Consolidated Balance Sheets, which excludes cash from discontinued operations. As part of the restatement, the Company has changed its presentation to include the net change in cash balances for discontinued operations as a component of net cash from operating activities. The result of this reclassification increased net cash from operating activities by $4 million, $66 million and $85 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Other Immaterial Errors

Certain other immaterial errors were identified and corrected in the appropriate periods.

The following tables set forth the previously reported and restated amounts of selected items within the consolidated balance sheets as of December 31, 2004 and 2003 and within the consolidated statements of comprehensive income and consolidated statements of cash flows for the years ended 2004, 2003 and 2002.

Selected Balance Sheet Data: ($ in millions)

	December 31, 2004 As Previously Reported	As Restated	December 31, 2003 As Previously Reported	As Restated
Assets				
Cash and cash equivalents	$ 1,408	$ 1,281	$ 1,737	$ 1,663
Short-term investments	$ 141	$ 268	$ 189	$ 264
Deferred income taxes current	$ 187	$ 218	$ 138	$ 198
Prepaid expenses	$ 93	$ 87	$ 64	$ 62
Other current assets	$ 713	$ 736	$ 527	$ 517
Total current assets	$ 4,938	$ 4,986	$ 4,888	$ 4,937
Electric generation and distribution assets	$ 22,434	$ 21,729	$ 20,918	$ 20,221
Accumulated depreciation	$ (5,353)	$ (5,259)	$ (4,527)	$ (4,462)
Property, plant and equipment, net	$ 18,788	$ 18,177	$ 18,402	$ 17,770
Deferred financing costs, net	$ 513	$ 343	$ 430	$ 302
Goodwill, net	$ 1,378	$ 1,419	$ 1,378	$ 1,421
Deferred income taxes-noncurrent	$ 813	$ 774	$ 791	$ 809
Other assets	$ 1,910	$ 1,832	$ 1,976	$ 1,976
Total other assets	$ 6,006	$ 5,760	$ 6,497	$ 6,430
Total assets	$ 29,732	$ 28,923	$ 29,787	$ 29,137
Liabilities and Stockholders Equity				
Accrued and other liabilities	$ 1,583	$ 1,656	$ 1,186	$ 1,248
Total current liabilities	$ 4,822	$ 4,894	$ 6,505	$ 6,566
Deferred income taxes, non-current	$ 685	$ 685	$ 822	$ 673
Other long-term liabilities	$ 3,261	$ 3,375	$ 3,062	$ 3,181
Total long-term liabilities	$ 21,660	$ 21,778	$ 21,708	$ 21,678
Minority interest	$ 1,605	$ 1,279	$ 1,029	$ 961
Additional paid-in capital	$ 6,341	$ 6,423	$ 5,737	$ 5,739
Accumulated deficit	$ 813	$ 1,815	$ 1,199	$ 2,107
Accumulated other comprehensive loss	$ 3,890	$ 3,643	$ 3,999	$ 3,706
Total stockholders equity	$ 1,645	$ 972	$ 545	$ (68)
Total liabilities and stockholders equity	$ 29,732	$ 28,923	$ 29,787	$ 29,137

Selected Comprehensive Income (Loss) Data: ($ in millions)

	For the Years Ended, December 31, 2004 As Previously Reported	As Restated	December 31, 2003 As Previously Reported	As Restated	December 31, 2002 As Previously Reported	As Restated(1)
Regulated revenues	$ 4,920	$ 4,897	$ 4,427	$ 4,425	$ 4,018	$ 4,015
Regulated cost of sales	$ 3,814	$ 3,781	$ 3,478	$ 3,449	$ 3,316	$ 3,292
Non-regulated cost of sales	$ 2,900	$ 2,900	$ 2,501	$ 2,505	$ 2,114	$ 2,117
Total cost of sales	$ 6,714	$ 6,681	$ 5,979	$ 5,954	$ 5,430	$ 5,409
Gross margin	$ 2,772	$ 2,782	$ 2,436	$ 2,459	$ 1,950	$ 1,968
Interest expense	$ 1,910	$ 1,941	$ 1,986	$ 1,986	$ 1,744	$ 1,792
Other income	$ 162	$ 163	$ 171	$ 171	$ 133	$ 144
Other expense	$ 151	$ 151	$ 110	$ 106	$ 83	$ 87
Loss on sale of investments and asset impairment expense	$ 41	$ 45	$ 201	$ 201	$ 473	$ 473
Goodwill impairment expense	$	$	$ 11	$ 11	$ 641	$ 738
Foreign currency transaction gains (losses) on net monetary position	$ (118)	$ (147)	$ 130	$ 99	$ (459)	$ (644)
Income tax expense	$ 249	$ 375	$ 204	$ 211	$ 293	$ 461
Minority interest expense (income)	$ 269	$ 198	$ 110	$ 120	$ (20)	$ (75)
Income (loss) from continuing operations	$ 366	$ 258	$ 332	$ 311	$ (1,646)	$ (2,064)
Income (loss) from discontinued operations	$ 20	$ 34	$ (787)	$ (787)	$ (1,567)	$ (1,561)
Net Income (loss)	$ 386	$ 292	$ (414)	$ (435)	$ (3,559)	$ (4,001)
Foreign currency translation adjustment	$ 151	$ 113	$ 492	$ 370	$ (1,672)	$ (1,358)
Unrealized derivative losses	$ (64)	$ (72)	$ 135	$ 141	$ (277)	$ (280)
Comprehensive income (loss)	$ 495	$ 355	$ 500	$ 362	$ (5,971)	$ (6,099)
BASIC EARNINGS (LOSS) PER SHARE:						
Income (loss) from continuing operations	$ 0.57	$ 0.40	$ 0.56	$ 0.52	$ (3.06)	$ (3.83)
Discontinued operations	0.03	0.06	(1.33)	(1.32)	(2.90)	(2.89)
Cumulative effect of accounting change			0.07	0.07	(0.64)	(0.70)
BASIC EARNINGS (LOSS) PER SHARE:	$ 0.60	$ 0.46	$ (0.70)	$ (0.73)	$ (6.60)	$ (7.42)
DILUTED EARNINGS (LOSS) PER SHARE:						
Income (loss) from continuing operations	$ 0.57	$ 0.40	$ 0.56	$ 0.52	$ (3.06)	$ (3.83)
Discontinued operations	0.03	0.05	(1.32)	(1.32)	(2.90)	(2.89)
Cumulative effect of accounting change			0.07	0.07	(0.64)	(0.70)
DILUTED EARNINGS (LOSS) PER SHARES:	$ 0.60	$ 0.45	$ (0.69)	$ (0.73)	$ (6.60)	$ (7.42)

(1) The cumulative effect of the errors described herein to stockholders equity at January 1, 2002 was a reduction of $349 million.

Selected Cash Flows Data: ($ in millions)

	For the Years Ended December 31, 2004 As Previously Reported	As Restated	2003 As Previously Reported	As Restated	2002 As Previously Reported	As Restated
Cash provided by operating activities:						
Net income (loss)	$ 386	$ 292	$ (414)	$ (435)	$ (3,559)	$ (4,001)
Depreciation and amortization of intangible assets	$ 841	$ 801	$ 781	$ 755	$ 837	$ 816
Loss from sale of investments and goodwill and asset impairment expense	$ 41	$ 45	$ 212	$ 215	$ 1,114	$ 1,211
(Gain) loss on disposal and impairment write-down associated with discontinued operations	$ (84)	$ (98)	$ 686	$ 686	$ 1,912	$ 1,906
Provision for deferred taxes	$ 46	$ 200	$ (96)	$ (89)	$ (307)	$ (152)
Minority interest expense (earnings)	$ 269	$ 198	$ 110	$ 120	$ (20)	$ (75)
Other	$ 242	$				