UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2006

Commission File Number 333-68630

Edison Mission Energy

(Exact name of registrant as specified in its charter)

Delaware	**95-4031807**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
18101 Von Karman Avenue, Suite 1700 **Irvine, California**	**92612**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(949) 752-5588**

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

None	**Not Applicable**
(Title of Class)	(Name of each exchange on which registered)

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

Common Stock, par value $0.01 per share

(Title of Class)

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

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

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

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ☐ NO ☒

Aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant as of June 30, 2006: $0. Number of shares outstanding of the registrant's Common Stock as of February 28, 2007: 100 shares (all shares held by an affiliate of the registrant).

The registrant meets the conditions set forth in General Instruction I.(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K under the reduced disclosure format.

DOCUMENTS INCORPORATED BY REFERENCE

None

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GLOSSARY

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

ARO	asset retirement obligations
BART	Best Available Retrofit Technology
Btu	British thermal units
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
Commonwealth Edison	Commonwealth Edison Company
CPS	Combined Pollutant Standard
EME	Edison Mission Energy
EME Homer City	EME Homer City Generation L.P.
EMMT	Edison Mission Marketing & Trading, Inc.
EPA	Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
EWG	exempt wholesale generator
Exelon Generation	Exelon Generation Company LLC
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN 46(R)	Financial Accounting Standards Interpretation No. 46, "Consolidation of Variable Interest Entities"
GAAP	generally accepted accounting principles
GWh	gigawatt-hours
IGCC	integrated gasification combined cycle
Illinois EPA	Illinois Environmental Protection Agency
Illinois Plants	EME's largest power plants (fossil fuel) located in Illinois
IPM	a consortium comprised of International Power plc (70%) and Mitsui & Co., Ltd. (30%)
ISO	independent system operator
LIBOR	London Interbank Offered Rate
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MEHC	Mission Energy Holding Company
Midwest Generation	Midwest Generation, LLC
MISO	Midwest Independent Transmission System Operator
MMBtu	million British thermal units
Moody's	Moody's Investors Service, Inc.
MPS	Multi-Pollutant Standards
MW	megawatts
MWh	megawatt-hours
NAPP	Northern Appalachian

NO_X	nitrogen oxide
NPDES	National Pollutant Discharge Elimination System
NSR	New Source Review
NYISO	New York Independent System Operator
PADEP	Pennsylvania Department of Environmental Protection
PG&E	Pacific Gas & Electric Company
PJM	PJM Interconnection, LLC
PRB	Powder River Basin
PUHCA 1935	Public Utility Holding Company Act of 1935 (as amended)
PUHCA 2005	Public Utility Holding Company Act of 2005
PURPA	Public Utility Regulatory Policies Act of 1978 (as amended)
RPM	reliability pricing model
RSG	Revenue Sufficiency Guarantee
RTO	regional transmission organizations
S&P	Standard & Poor's Ratings Services
SCE	Southern California Edison Company
SECA	Seams Elimination Cost Adjustment
SFAS	Statement of Financial Accounting Standards issued by the FASB
SFAS No. 123(R)	Statement of Financial Accounting Standards No. 123(R), "Share-Based Payment"
SFAS No. 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS No. 144	Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets"
SFAS No. 155	Statement of Financial Accounting Standards No. 155, "Accounting for Certain Hybrid Financial Instruments"
SFAS No. 157	Statement of Financial Accounting Standards No. 157, "Fair Value Measurements"
SFAS No. 158	Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Post-Retirement Plans"
SFAS No. 98	Statement of Financial Accounting Standards No. 98, "Sale-Leaseback Transactions Involving Real Estate"
SIP	state implementation plan
SO_2	sulfur dioxide
US EPA	United States Environmental Protection Agency

PART I

ITEM 1. BUSINESS

The Company

EME is an independent power producer engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from independent power production facilities. EME also conducts hedging and energy trading activities in power markets open to competition. EME is a wholly owned subsidiary of MEHC. Edison International is EME's ultimate parent company. Edison International also owns SCE, one of the largest electric utilities in the United States.

EME was formed in 1986 with two domestic operating power plants. As of December 31, 2006, EME's subsidiaries and affiliates owned or leased interests in 29 operating power plants with an aggregate net physical capacity of 10,473 MW of which EME's capacity pro rata share was 9,303 MW. At December 31, 2006, five projects totaling 342 MW of generating capacity were under construction.

EME is incorporated under the laws of the State of Delaware. EME's headquarters and principal executive offices are located at 18101 Von Karman Avenue, Suite 1700, Irvine, California 92612, and EME's telephone number is (949) 752-5588. Unless indicated otherwise or the context otherwise requires, references to EME in this annual report are with respect to EME and its consolidated subsidiaries and the partnerships or limited liability entities through which EME and its partners own and manage their project investments.

EME's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports, are electronically filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and are available on the Securities and Exchange Commission's internet web site at http://www.sec.gov.

Management and Organizational Changes

EME implemented management and organizational changes in 2005 to streamline its reporting relationships and eliminate its regional management structure. In addition, EME and its affiliate, Edison Capital, have combined their management teams located in Irvine, California and combined their wind development efforts. In this regard, EME and Edison Capital entered into a services agreement effective December 26, 2005. Under this services agreement, all existing employees of Edison Capital on the effective date of the agreement were transferred to EME, and EME provides accounting, legal, tax, management and administrative services to Edison Capital and its subsidiaries of the type previously provided by the transferred employees. Edison Capital and its subsidiaries continue to operate as independent legal entities separate and apart from EME, and EME has not assumed any obligation for the performance of any of Edison Capital's obligations to any party, whether with respect to its investment portfolio or with respect to any of the creditors of Edison Capital or its subsidiaries.

Forward-Looking Statements

This annual report on Form 10-K contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. These statements reflect EME's current expectations and projections about future events based on EME's knowledge of present facts and circumstances and assumptions about future events and include any statement that does not directly relate to a historical or current fact. Other information distributed by EME that is incorporated in this annual report, or that refers to or incorporates this annual report, may also contain forward-looking statements. In this annual report and elsewhere, the words "expects," "believes," "anticipates," "estimates," "projects," "intends," "plans," "probable," "may," "will," "could," "would," "should," and variations of such words and similar expressions, or discussions of strategy or plans, are intended to identify forward-looking statements. Such statements necessarily involve risks and uncertainties that could cause actual results to differ materially from those anticipated. Some of the risks, uncertainties and other important factors that could cause results to differ, or that otherwise could impact EME or its subsidiaries, include but are not limited to:

- supply and demand for electric capacity and energy, and the resulting prices and dispatch volumes, in the wholesale markets to which EME's generating units have access;
- the cost and availability of coal, natural gas, and fuel oil, and associated transportation;
- market volatility and other market conditions that could increase EME's obligations to post collateral beyond the amounts currently expected, and the potential effect of such conditions on the ability of EME and its subsidiaries to provide sufficient collateral in support of their hedging activities and purchases of fuel;
- the cost and availability of emission credits or allowances;
- transmission congestion in and to each market area and the resulting differences in prices between delivery points;
- governmental, statutory, regulatory or administrative changes or initiatives affecting EME or the electricity industry generally, including the market structure rules applicable to each market;
- environmental regulations that could require additional expenditures or otherwise affect EME's cost and manner of doing business;
- the ability of EME to successfully implement its business strategy, including development projects and future acquisitions;
- the extent of additional supplies of capacity, energy and ancillary services from current competitors or new market entrants, including the development of new generation facilities and technologies that may be able to produce electricity at a lower cost than EME's generating facilities and/or increased access by competitors to EME's markets as a result of transmission upgrades;
- the ability of EME to borrow funds and access capital markets on favorable terms;
- the difficulty of predicting wholesale prices, transmission congestion, energy demand, and other aspects of the complex and volatile markets in which EME and its subsidiaries participate;
- operating risks, including equipment failure, availability, heat rate, output and availability and cost of spare parts and repairs;
- effects of legal proceedings, changes in or interpretations of tax laws, rates or policies, and changes in accounting standards;
- general political, economic and business conditions;
- weather conditions, natural disasters and other unforeseen events; and
- EME's continued participation and the continued participation by EME's subsidiaries in tax-allocation and payment agreements with EME's respective affiliates.

Certain of the risk factors listed above are discussed in more detail in "Item 1A. Risk Factors" below and in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Market Risk Exposures." Additional information about the risk factors listed above and other risks and uncertainties is contained throughout this annual report. Readers are urged to read this entire annual report, including the information incorporated by reference, and carefully consider the risks, uncertainties and other factors that affect EME's business. Forward-looking statements speak only as of the date they are made, and EME is not obligated to publicly update or revise forward-looking statements. Readers should review future reports filed by EME with the Securities and Exchange Commission.

Business Strategy

EME's business strategy includes the following core elements:

- Optimizing the value of its existing generation assets through:
  - operational excellence focused on long-term cost effective maintenance;
  - integration of commercial marketing and trading activities with plant operations to enhance gross margin; and
  - effective participation in regulatory rule-making in markets where EME operates.
- Diversifying the fuel type of its generation assets through:
  - developing and acquiring new renewable energy projects, primarily wind;
  - developing and acquiring natural gas-fired power projects in locations where existing or projected capacity for generation is constrained; and
  - developing new clean coal generation projects such as IGCC.
- Entering into more mid- to long-term power sales contracts in order to complement its merchant sales activities.
- Reducing cash flow volatility from merchant power plants through asset-based commodity hedging activities.
- Leveraging the knowledge and expertise in trading to enhance financial performance within a disciplined risk management structure.

Description of the Industry

Electric Power Industry

The United States electric industry, including companies engaged in providing generation, transmission, distribution and ancillary services, has undergone significant deregulation, which has led to increased competition. Until the enactment of PURPA, utilities and government-owned power agencies were the only producers of bulk electric power intended for sale to third parties in the United States. PURPA encouraged the development of independent power by removing regulatory constraints relating to the production and sale of electric energy by certain non-utilities and requiring electric utilities to buy electricity from specified types of non-utility power producers, known as qualifying facilities, under specified conditions. The passage of the Energy Policy Act of 1992 further encouraged the development of independent power by significantly expanding the options available to independent power producers with respect to their regulatory status and by liberalizing transmission access. In addition, in EPAct 2005, Congress made several changes to PURPA and other statutory provisions recognizing that a significant market for electric power produced by independent power producers, such as EME, has developed in the United States and indicating that competitive wholesale electricity markets have become accepted as a fundamental aspect of the electricity industry.

As part of the regulatory developments discussed above, the FERC encouraged the formation of ISOs and RTOs. In those areas where ISOs and RTOs have been formed, market participants have expanded access to transmission service. ISOs and RTOs may also operate real-time and day-ahead energy and ancillary service markets, which are governed by FERC-approved tariffs and market rules. The development of such organized markets into which independent power producers are able to sell has reduced their dependence on bilateral contracts with electric utilities. See further discussion of regulations under "Regulatory Matters—U.S. Federal Energy Regulation."

Electric Power Markets

EME's largest power plants are its fossil fuel power plants located in Illinois, which are collectively referred to as the Illinois Plants in this annual report, and the Homer City electric generating station located in Pennsylvania, which is referred to as the Homer City facilities in this annual report. The Illinois Plants and the Homer City facilities sell power into PJM. PJM operates a wholesale spot energy market and determines the market-clearing price for each hour based on bids submitted by participating generators which indicate the minimum prices a bidder is willing to accept to be dispatched at various incremental generation levels. PJM conducts both day-ahead and real-time energy markets. PJM's energy markets are based on locational marginal pricing, which establishes hourly prices at specific locations throughout PJM. Locational marginal pricing is determined by considering a number of factors, including generator bids, load requirements, transmission congestion and transmission losses. PJM requires all load serving entities to maintain prescribed levels of capacity, including a reserve margin, to ensure system reliability. PJM also determines the amount of capacity available from each specific generator and operates capacity markets. PJM's capacity markets have a single market-clearing price. Load serving entities and generators, such as EME's subsidiaries Midwest Generation, with respect to the Illinois Plants, and EME Homer City, with respect to the Homer City facilities, may participate in PJM's capacity markets or transact capacity sales on a bilateral basis.

The Homer City facilities have direct, high voltage interconnections to both PJM and the NYISO, which controls the transmission grid and energy and capacity markets for New York State. As in PJM, the market-clearing price for NYISO's day-ahead and real-time energy markets is set by supplier generation bids and customer demand bids.

On April 1, 2005, the MISO commenced operation, linking portions of Illinois, Wisconsin, Indiana, Michigan, and Ohio, as well as other states in the region. In the MISO, there is a bilateral market and day-ahead and real-time markets based on locational marginal pricing similar to that of PJM. While EME does not own generating facilities within the MISO, its opening has further facilitated transparency of prices and provided additional market liquidity to support risk management and trading strategies.

For a discussion of the market risks related to the sale of electricity from these generating facilities, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Market Risk Exposures."

Competition

EME is subject to intense competition from energy marketers, utilities, industrial companies and other independent power producers. For a number of years, natural gas has been the fuel of choice for new power generation facilities for economic, operational and environmental reasons. While natural gas-fired facilities will continue to be an important part of the nation's generation portfolio, some regulated utilities are now constructing clean coal units and units powered by renewable resources, often with subsidies or under legislative mandate. These utilities generally have a lower cost of capital than most independent power producers and often are able to recover fixed costs through rate base mechanisms, allowing them to build, buy and upgrade generation without relying exclusively on market clearing prices to recover their investments.

Where EME sells power from plants from which the output is not committed to be sold under long-term contracts, commonly referred to as merchant plants, EME is subject to market fluctuations in prices based on a number of factors, including the amount of capacity available to meet demand, the price and availability of fuel and the presence of transmission constraints. Some of EME's competitors, such as electric utilities and distribution companies, have their own generation capacity, including nuclear generation. These companies, generally larger than EME, have a lower cost of capital and may have competitive advantages as a result of their scale and location of their generation facilities.

Operating Segments

EME operates in one line of business, independent power production, with all its continuing operations located in the United States, except the Doga project in Turkey. Operating revenues are primarily related to the sale of power generated from the Illinois Plants and the Homer City facilities. EME is headquartered in Irvine, California with additional offices located in Chicago, Illinois and Boston, Massachusetts.

Overview of Facilities

As of December 31, 2006, EME's operations consisted of ownership or leasehold interests in the following operating power plants:

Power Plants	Location	Primary Electric Purchaser(2)	Fuel Type	Ownership Interest	Net Physical Capacity (in MW)	EME's Capacity Pro Rata Share (in MW)	Number of plants
Merchant Power Plants							
Illinois Plants(1)	Illinois	PJM	Coal/Oil/Gas	100%	5,918	5,918	6
Homer City(1)	Pennsylvania	PJM	Coal	100%	1,884	1,884	1
Contracted Power Plants							
Domestic							
Big 4 Projects							
Kern River(1)	California	SCE	Natural Gas	50%	300	150	1
Midway-Sunset(1)	California	SCE	Natural Gas	50%	225	113	1
Sycamore(1)	California	SCE	Natural Gas	50%	300	150	1
Watson	California	SCE	Natural Gas	49%	385	189	1
Westside Projects							
Coalinga(1)	California	PG&E	Natural Gas	50%	38	19	1
Mid-Set(1)	California	PG&E	Natural Gas	50%	38	19	1
Salinas River(1)	California	PG&E	Natural Gas	50%	38	19	1
Sargent Canyon(1)	California	PG&E	Natural Gas	50%	38	19	1
American Bituminous(1)	West Virginia	MPC	Waste Coal	50%	80	40	1
March Point	Washington	PSE	Natural Gas	50%	140	70	1
Sunrise(1)	California	CDWR	Natural Gas	50%	572	286	1
Huntington	New York	LIPA	Biomass	38%	25	9	1
Wind Projects							
San Juan Mesa(1)	New Mexico	SPS	Wind	75%	120	90	1
Minnesota Wind Projects	Minnesota	NSPC/IPLC	Wind	75-99%	83	75	7
Storm Lake	Iowa	MEC	Wind	100%	109	109	1
International							
Doga(1)	Turkey	TEDAS	Natural Gas	80%	180	144	1
Total					10,473	9,303	29

(1) Plant is operated under contract by an EME operations and maintenance subsidiary (partially owned plants) or plant is operated directly by an EME subsidiary (wholly owned plants).

(2) Electric purchaser abbreviations are as follows:

PJM	PJM Interconnection, LLC	LIPA	Long Island Power Authority
SCE	Southern California Edison Company	SPS	Southwestern Public Service
PG&E	Pacific Gas & Electric Company	NSPC	Northern States Power Company
MPC	Monongahela Power Company	IPLC	Interstate Power and Light Company
PSE	Puget Sound Energy, Inc.	MEC	Mid-American Energy Company
CDWR	California Department of Water Resources	TEDAS	Türkiye Elektrik Dağitim Anonim Sirketi

A description of EME's larger power plants and major investments in energy projects is set forth below. In addition to the facilities and power plants that EME owns, EME uses the term "its" in regard to facilities and power plants that EME or an EME subsidiary operates under sale-leaseback arrangements.

Illinois Plants

On December 15, 1999, Midwest Generation completed a transaction with Commonwealth Edison, now a subsidiary of Exelon Corporation, to acquire the Illinois Plants. The Illinois Plants are located in the Mid-America Interconnected Network, which has transmission connections to the East Central Area Reliability Council and other regional markets.

The Illinois Plants include the following:

Operating Plant or Site	Location	Leased/ Owned	Fuel	Megawatts
Electric Generating Facilities				
Crawford Station	Chicago, Illinois	owned	coal	542
Fisk Station	Chicago, Illinois	owned	coal	326
Joliet Unit 6	Joliet, Illinois	owned	coal	290
Joliet Units 7 and 8	Joliet, Illinois	leased	coal	1,044
Powerton Station	Pekin, Illinois	leased	coal	1,538
Waukegan Station	Waukegan, Illinois	owned	coal	781(1)
Will County Station	Romeoville, Illinois	owned	coal	1,092(2)
Peaking Units				
Fisk	Chicago, Illinois	owned	oil/gas	197
Waukegan	Waukegan, Illinois	owned	oil/gas	108
Total				5,918

Other Plant or Site	
Collins Station(3)	Grundy County, Illinois
Crawford peaker(4)	Chicago, Illinois
Joliet peaker(5)	Joliet, Illinois
Calumet peaker(5)	Chicago, Illinois
Electric Junction peaker(5)	Aurora, Illinois
Lombard peaker(5)	Lombard, Illinois
Sabrooke peaker(5)	Rockford, Illinois

(1) The Waukegan Station is comprised of Units 6, 7 and 8. Midwest Generation has agreed with the Illinois EPA to shut down permanently Waukegan Station Unit 6 (100 MW) on or before December 31, 2007. For further discussion, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Environmental Matters and Regulations—Air Quality Regulation—Clean Air Act—Illinois."

(2) The Will County Station is comprised of Units 1, 2, 3, and 4. Operations at Will County Station Units 1 and 2 (totaling 310 MW) were returned to service in late 2004 after being suspended in January 2003. Midwest Generation has agreed with the Illinois EPA to shut down permanently Will County Station Units 1 and 2 on or before December 31, 2010. For further discussion, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Environmental Matters and Regulations—Air Quality Regulation—Clean Air Act—Illinois."

(3) All Collins Station units ceased operations and were decommissioned on or before December 31, 2004.

(4) Peaking units ceased operations as of April 21, 2005.

(5) Peaking units ceased operations as of December 31, 2004.

As part of the purchase of the Illinois Plants, EME assigned its right to purchase the Collins Station to third-party entities and Midwest Generation simultaneously entered into a long-term lease arrangement of the Collins Station with these third-party entities. In April 2004, Midwest Generation terminated the Collins Station lease through a negotiated transaction with the lease equity investor and received title to the Collins Station as part of the transaction. Following the lease termination, Midwest Generation permanently ceased operations at the Collins Station, effective September 30, 2004, and decommissioned the plant prior to December 31, 2004, by which time all units were permanently retired from service, disconnected from the grid, and rendered inoperable, with all operating permits surrendered.

In August 2000, EME completed sale-leaseback transactions involving its Powerton and Units 7 and 8 of its Joliet power facilities. EME sold these assets to third parties to obtain capital to repay corporate debt and entered into long-term leases of the facilities from these third parties to maintain control of the use of the power plants during the terms of the leases. See "Off-Balance Sheet Transactions" section in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Illinois Power Sales

Energy generated at the Illinois Plants was historically sold under three power purchase agreements between Midwest Generation and Exelon Generation under which Exelon Generation was obligated to make capacity payments for the plants under contract and energy payments for the energy produced by the Illinois Plants and taken by Exelon Generation. The power purchase agreements began on December 15, 1999, and all were terminated by December 31, 2004.

All the energy and capacity from the Illinois Plants is now sold under terms, including price and quantity, arranged by EMMT, an EME subsidiary engaged in the power marketing and trading business, with customers through a combination of bilateral agreements, forward energy sales and spot market sales. Thus, EME is subject to market risks related to the price of energy and capacity from the Illinois Plants. Power generated at the Illinois Plants is generally sold into the PJM market. Capacity prices for merchant energy sales within PJM are, and are expected in the near term to remain, at a level unlikely to generate significant revenue for Midwest Generation.

For a discussion of the risks related to Midwest Generation's sale of electricity, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Market Risk Exposures."

Transmission

Prior to May 1, 2004, sales of power produced by Midwest Generation required using transmission that had to be obtained from Commonwealth Edison. As discussed previously, the Illinois Plants are now dispatched into the PJM market. Sales may also be made from PJM into the MISO, where there is a single rate for transmission.

On November 18, 2004, the FERC issued an order eliminating regional through and out transmission rates in the region encompassed by PJM and the MISO. The effect of this order was to eliminate so-called rate pancaking between PJM and the MISO on a prospective basis. Rate pancaking occurs when energy must move through multiple, separately priced transmission systems to travel from its point of production to its point of delivery, and each transmission owner along the line charges separately for the use of its system. At the same time, the FERC also imposed a transitional revenue recovery mechanism which has created controversy and some continuing uncertainty as to its impact on transactions in the region. The mechanism required the filing of tariffs by PJM and the MISO imposing a SECA, to be in effect until May 1, 2006, to compensate the "new PJM companies"—AEP, Commonwealth Edison and Dayton Power & Light, among others—for lost revenues attributable to the elimination of such rates. On November 30, 2004, the FERC clarified that SECAs can be recovered for lost revenues associated with elimination of intra-RTO pancaked rates.

The response to the November 18 and November 30 orders from the parties potentially liable for the SECAs was strongly negative. Rehearings were sought by a broad range of interests that are opposed to the imposition of SECAs. Although both PJM and the MISO have made tariff filings with the FERC that purport to comply with the orders and eliminate through and out transmission rates as of December 1, 2004, numerous protests to such filings have been made, challenging SECAs on legal and equitable grounds and evidentiary hearings have been held by the FERC. Pending further orders of the FERC and/or the outcome of future hearings, under the provisions of the PJM tariff as filed, Midwest Generation is currently not subject to SECAs with respect to its sales of power within PJM. It is not possible, however, to predict the outcome of the FERC proceedings or to rule out the possibility that Midwest Generation could be ordered in the future to pay SECAs with respect to sales within PJM after December 1, 2004.

For further discussion of the market risks related to Midwest Generation's transmission service, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Market Risk Exposures."

Fuel Supply

Coal is used to fuel 5,613 MW of Midwest Generation's generating capacity. The coal is purchased from several suppliers that operate mines in the Southern PRB of Wyoming. The total volume of coal consumed annually is largely dependent on the amount of generation and ranges between 16 million to 20 million tons.

All coal is transported under long-term transportation agreements with the Union Pacific Railroad and various delivering carriers. As of December 31, 2006, Midwest Generation leased approximately 4,200 railcars to transport the coal from the mines to the generating stations and the leases have remaining terms that range from less than one year to 13 years, with options to extend the leases or purchase some railcars at the end of the lease terms. The coal is transported nearly 1,200 miles from the mines to the Illinois Plants.

Coal for the Fisk and Crawford Stations is first shipped by rail to the Will County Station where it is transferred from the railcars, blended as necessary to meet station specifications, and loaded into river barges. These barges are towed to the stations by an independent contractor under a transportation agreement with Midwest Generation.

Midwest Generation has approximately 305 MW of peaking capacity in the form of simple cycle combustion turbines at the Fisk and Waukegan Stations. These units are fueled with distillate fuel oils.

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Contractual Obligations, Commitments and Contingencies," for additional discussion of contractual commitments related to Midwest Generation's fuel supply and coal transportation contracts.

Homer City Facilities

On March 18, 1999, EME Homer City completed a transaction with GPU, Inc., New York State Electric & Gas Corporation and their respective affiliates to acquire the Homer City facilities. These facilities consist of three coal-fired boilers and steam turbine-generator units (referred to as Units 1, 2 and 3 in this annual report), one coal cleaning facility, water supply provided by a reservoir known as Two Lick Dam and associated support facilities in the mid-Atlantic region of the United States.

On December 7, 2001, EME Homer City completed a sale-leaseback of the Homer City facilities to third-party lessors. EME Homer City sold the Homer City facilities to obtain capital to repay corporate debt and entered into long-term leases to continue to operate the Homer City facilities during the terms of the leases. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Off-Balance Sheet Transactions."

Fuel Supply

Units 1 and 2 typically consume approximately 3.3 million to 3.5 million tons of mid-range sulfur coal per year. Approximately 90% or more of this coal is obtained under contracts with the remainder purchased in the spot market as needed. Two types of coal are purchased, ready to burn coal and raw coal. Ready to burn coal is of a quality that can be burned directly in Units 1 and 2, whereas the raw coal purchased for consumption by Units 1 and 2 must be cleaned in the Homer City coal cleaning facility, which has the capacity to clean up to 5 million tons of coal per year.

Unit 3 consumes approximately 2 million tons of coal per year. EME Homer City purchases the majority of its Unit 3 coal under contracts with the balance purchased in the spot market. A wet scrubber flue gas desulfurization system for Unit 3 enables this unit to burn less expensive, higher sulfur coal, while still meeting environmental standards for emission control.

In general, the coal purchased for all three units originates from mines that are within approximately 100 miles of the Homer City facilities. It is delivered to the station by truck and by rail.

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Contractual Obligations, Commitments and Contingencies," for additional discussion of contractual commitments related to EME Homer City's fuel supply and coal transportation contracts.

Emission Allowances for the Homer City Facilities and Illinois Plants

Certain state and federal environmental laws require power plant operators to hold or obtain emission allowances equal, on an annual basis, to their plants' emissions of SO_2 and, on a seasonal basis, to their plants' emissions of NO_x. Emission allowances were acquired as part of the acquisition of the Homer City facilities and the Illinois Plants. Additional allowances are purchased by EME Homer City and Midwest Generation when operations make this necessary and are sold when they have more than needed for planned levels of operation.

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Environmental Matters and Regulations" for a discussion of environmental regulations related to emissions. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Market Risk Exposures—Commodity Price Risk—Emission Allowances Price Risk" for a discussion of price risks related to the purchase or sale of emission allowances.

Big 4 Projects

EME owns partnership investments in Kern River Cogeneration Company, Midway-Sunset Cogeneration Company, Sycamore Cogeneration Company and Watson Cogeneration Company, as described below. These projects sell power to SCE, an affiliate of EME. Because these projects have similar economic characteristics and have been used, collectively, to obtain financing by Edison Mission Energy Funding Corp., a special purpose entity, EME views these projects collectively and refers to them *as the Big 4 projects. See "Item 8. Financial Statements and Supplementary Data—Edison Mission Energy and Subsidiaries Notes to Consolidated Financial Statements—Note 2. Summary of Significant Accounting Policies," for discussion of EME's accounting for this entity.*

Kern River Cogeneration Plant

EME owns a 50% partnership interest in Kern River Cogeneration Company, which owns a 300 MW natural gas-fired cogeneration facility located near Bakersfield, California, which EME refers to as the Kern River project. Kern River Cogeneration's prior long-term power purchase agreement with SCE and its steam supply agreement with Texaco Exploration and Production Inc., a wholly owned subsidiary of Chevron Corporation, both expired on August 9, 2005. On August 10, 2005, Kern River Cogeneration entered into a Reformed Standard Offer No. 1 As-Available Energy and Capacity Power Purchase Agreement with SCE, which was in effect until June 1, 2006 when it was replaced by a new five-year bilateral agreement with SCE. On August 10, 2005, Kern River Cogeneration also entered into a new Steam Purchase and Sale Agreement with Chevron North America Exploration and Production Company, a division of Chevron U.S.A., Inc., with a term equivalent to the new power purchase agreement.

Midway-Sunset Cogeneration Plant

EME owns a 50% partnership interest in Midway-Sunset Cogeneration Company, which owns a 225 MW natural gas-fired cogeneration facility located near Taft, California, which EME refers to as the Midway-Sunset project. Midway-Sunset Cogeneration sells electricity to SCE, Aera Energy LLC and PG&E under power purchase agreements that expire in 2009 and steam to Aera Energy LLC under a steam supply agreement that also expires in 2009.

Sycamore Cogeneration Plant

EME owns a 50% partnership interest in Sycamore Cogeneration Company, which owns and operates a 300 MW natural gas-fired cogeneration facility located near Bakersfield, California, which EME refers to as the Sycamore project. Sycamore Cogeneration sells electricity to SCE under a power purchase agreement that expires on December 31, 2007 and steam to Chevron North America Exploration and Production Company under a steam supply agreement that also expires on December 31, 2007.

Watson Cogeneration Plant

EME owns a 49% partnership interest in Watson Cogeneration Company, which owns a 385 MW natural gas-fired cogeneration facility located in Carson, California, which EME refers to as the Watson project. Watson Cogeneration sells electricity to SCE and to BP West Coast Products LLC under power purchase agreements that expire in 2008 and steam to BP West Coast Products LLC under a steam supply agreement that also expires in 2008.

Other Power Plants

Westside Power Plants

EME owns partnership investments in Coalinga Cogeneration Company, Mid-Set Cogeneration Company, Salinas River Cogeneration Company, and Sargent Canyon Cogeneration Company. Due to similar economic characteristics, EME views these projects collectively and refers to them as the Westside projects. EME owns a 50% partnership interest in each of the companies listed above and each company owns a 38 MW natural gas-fired cogeneration facility located in California. Three of these projects sell electricity to PG&E under 15-year power purchase agreements which expire during the first quarter of 2007. These projects will execute agreements with PG&E for the continued sale of electricity at "as available" rates. Mid-Set Cogeneration's original power purchase agreement with PG&E expired in May 2004. Mid-Set Cogeneration continues to sell electricity to PG&E at "as available" rates under an agreement that expires on December 31, 2009.

American Bituminous Power Plant

EME owns a 50% interest in American Bituminous Power Partners, L.P., which owns an 80 MW waste coal facility located in Grant Town, West Virginia, which EME refers to as the Ambit project. Ambit sells electricity to Monongahela Power Company under a power purchase agreement that expires in 2035.

March Point Cogeneration Plant

EME owns a 50% partnership interest in March Point Cogeneration Company, which owns a 140 MW natural gas-fired cogeneration facility located in Anacortes, Washington, which EME refers to as the March Point project. The March Point project consists of two phases. Phase 1 is an 80 MW gas turbine cogeneration facility and Phase 2 is a 60 MW gas turbine combined cycle facility. March Point Cogeneration sells electricity to Puget Sound Energy, Inc. under a power purchase agreement that expires in 2011 and steam to Equilon Enterprises, LLC under a steam supply agreement that also expires in 2011. During the third quarter of 2005, EME recorded a $55 million charge to impair fully its equity investment in the March Point project due to the adverse impact on cash flows from increases in long-term natural gas prices. For further discussion, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Results of Continuing Operations—Earnings from Unconsolidated Affiliates."

Sunrise Power Plant

EME owns a 50% interest in Sunrise Power Company, LLC, which owns a 572 MW natural gas-fired facility in Kern County, California, which EME refers to as the Sunrise project. Sunrise Power entered into a long-term power purchase agreement with the California Department of Water Resources in June 2001, which expires in 2012.

Huntington Biomass Project

EME owns a 38% limited partnership interest in Covanta Huntington LP, which owns a 25 MW waste-to-energy facility located near the Town of Huntington, New York, which EME refers to as the Huntington project. The project processes waste materials under a solid waste disposal services agreement with the Town of Huntington, which is set to expire in 2012 with an option to renew. The project also sells electricity to Long Island Power Authority under a power purchase agreement that expires in 2012.

San Juan Mesa Wind Power Plant

EME owns a 75% interest in San Juan Mesa Wind Project LLC, which owns a 120 MW wind ranch located near Elida, New Mexico, which EME refers to as the San Juan Mesa wind project. The project sells electricity to Southwestern Public Service, a subsidiary of Xcel Energy, under a power purchase agreement that expires in 2025. The San Juan Mesa wind project achieved commercial operation in December 2005.

Minnesota Wind Projects

EME owns interests of between 75% and 99% in 37 separate Minnesota limited liability companies, each of which owns a small wind-powered electric generation facility in Murray, Cottonwood, Lincoln and Pipestone counties in Minnesota, which EME refers to collectively as the Minnesota wind projects. The Minnesota wind projects collectively total approximately 83 MW. Each of the Minnesota wind projects sells electricity to either (i) Northern States Power Company under a power purchase agreement that expires between 2025 and 2034 or (ii) Interstate Power and Light Company under a power purchase agreement that expires in 2021.

Storm Lake Wind Power Plant

EME owns a 100% interest in Storm Lake Power Partners I LLC, which owns a 109 MW wind ranch located near Alta, Iowa, which EME refers to as the Storm Lake wind project. The project sells electricity to Mid-American Energy Company under a power purchase agreement that expires in 2020.

Doga Cogeneration Plant

EME owns an 80% interest in Doga Enerji, which owns a 180 MW natural gas-fired cogeneration plant near Istanbul, Turkey, which EME refers to as the Doga project. Doga Enerji sells electricity to Türkiye Elektrik Dağitim Anonim Sirketi, commonly known as TEDAS, under a power purchase agreement that expires in 2019.

Overview of Projects under Construction

As of December 31, 2006, EME had the projects described below under construction. Each project will, after its completion, use wind to generate electricity from turbines, which will be sold pursuant to the project's power purchase agreement.

Wildorado Wind Power Plant

EME owns a 99.9% interest in Wildorado Wind, L.P., which owns a 161 MW wind farm located in the panhandle of northern Texas, which EME refers to as the Wildorado wind project. This project started construction in April 2006 and is scheduled for completion in April 2007. The project will sell electricity to Southwestern Public Service Company under a 20-year power purchase agreement.

Sleeping Bear Wind Power Plant

EME owns a 100% interest in Sleeping Bear LLC, which owns a 95 MW wind farm located in northwestern Oklahoma, which EME refers to as the Sleeping Bear wind project. This project started construction in October 2006 and is scheduled for completion in the spring of 2007. The project will sell electricity to Public Service Company of Oklahoma, a unit of American Electric Power, under a 25-year power purchase agreement.

Jeffers Wind Power Plant

EME owns a 99.9% interest in Jeffers Wind 20 LLC, which owns a 50 MW wind farm located in western Minnesota, which EME refers to as the Jeffers wind project. This project started construction in October 2006 and is scheduled for completion in the summer of 2007. The project will sell electricity to Northern States Power Company under Minnesota's Community-Based Energy Development Program under a 20-year power purchase agreement.

Crosswinds Wind Project

EME owns a 99% interest in Crosswinds Energy Projects consisting of 10 separate limited liability companies, which collectively own a 21 MW wind farm located in northwestern Iowa, which EME refers to as the Crosswinds wind project. This project started construction in September 2006 and is scheduled for completion in the spring of 2007. The project will sell electricity to Corn Belt Power Cooperative under a 20-year power purchase agreement.

Hardin Wind Project

EME owns a 99% interest in Hardin Hilltop Projects consisting of seven separate limited liability companies, which collectively own a 15 MW wind farm located in western Iowa, which EME refers to as the Hardin wind project. This project started construction in August 2006 and is scheduled for completion in the spring of 2007. The project will sell electricity to Interstate Power and Light Company under a 20-year power purchase agreement.

Business Development

Wind Projects

EME expects to make significant investments in wind projects during the next several years. Historically, wind projects have received federal subsidies in the form of production tax credits. In August 2005, production tax credits were made available for new wind projects placed in service by December 31, 2007 under EPAct 2005. In December 2006, the deadline for production tax credits was extended for one year to apply to new wind projects placed in service by December 31, 2008.

In seeking to find and invest in new wind projects, EME has teamed with third-party development companies through joint development agreements that provide for funding of development costs through loans and joint decision-making on key contractual agreements (e.g., power purchase contracts, site agreements and permits). Joint development agreements and development loans may be for a specific project or a group of identified and future projects and generally grant EME the exclusive right to acquire related projects. At December 31, 2006, joint development agreements were in place for multiple potential projects located in Pennsylvania, Illinois, Maine, Maryland, New York, West Virginia and Wisconsin. See "Item 8. Financial Statements and Supplementary Data—Edison Mission Energy and Subsidiaries Notes to Consolidated Financial Statements—Note 4. Acquisitions and Consolidations—Consolidations" for further discussion.

In general, EME funds development costs under joint development agreements through loans (referred to as development loans) which are secured by project specific assets. A project's development loans are repaid upon the completion of the project. If the project is purchased by EME, repayment is made from proceeds received from EME in connection with the purchase. In the event EME declines to purchase a project, repayment is made from proceeds received from the sale of the project to third parties or from other sources as available.

In addition to joint development agreements, EME may purchase wind projects from third-party developers in various stages of development, construction or operation. In order to support investment in wind projects, EME has negotiated turbine supply agreements in advance of specific project requirements. As of December 31, 2006, EME has purchased turbines for future wind projects totaling 487 MW. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Contractual Obligations, Commitments and Contingencies—Purchase Obligations—Turbine Commitments" for further discussion.

Thermal Projects

EME expects to make investments in thermal projects during the next several years. As part of its development efforts, EME is in the process of obtaining permits for two sites in Southern California for peaker plants. Generally, it is expected that thermal projects in which EME invests will sell electricity under long-term power purchase contracts. EME actively participates in bids to utilities in response to requests for proposals to build new generation and may acquire existing generation in selected markets.

In June 2006, subsidiaries of EME and BP America Inc. formed Carson Hydrogen Power LLC for the development of a power project to be located in Carson, California. Carson Hydrogen is a development stage enterprise for a planned industrial gasification project that will integrate proven gasification, power generation and enhanced oil recovery technologies. On November 29, 2006, the project was allocated $90 million of qualifying gasification project credits under Section 48B of the Internal Revenue Code. Carson Hydrogen is conducting preliminary development, including engineering, financial analysis and commercial arrangements, required for project implementation.

Hedging and Trading Activities

EME's power marketing and trading subsidiary, EMMT, markets the energy and capacity of EME's merchant generating fleet and, in addition, trades electric power and energy and related commodity and financial products, including forwards, futures, options and swaps. EMMT segregates its marketing and trading activities into two categories:

- *Hedging*—EMMT engages in the sale and hedging of electricity and purchase of fuels (other than coal) through intercompany contracts with EME's subsidiaries that own or lease the Illinois Plants and the Homer City facilities. The objective of these activities is to sell the output of the power plants on a forward basis or to hedge the risk of future change in the price of electricity, thereby increasing the predictability of earnings and cash flows. EMMT also conducts hedging associated with the purchase of fuels, including natural gas and fuel oil. Transactions entered into related to hedging activities are designated separately from EMMT's trading activities and are recorded in what EMMT calls its hedge book. Not all of the contracts entered into by EMMT for hedging activities qualify for hedge accounting under SFAS No. 133. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Market Risk Exposures—Accounting for Energy Contracts" for a discussion of accounting for derivative contracts.
- *Trading*—As part of its trading activities, EMMT seeks to generate profit from the volatility of the price of electricity, fuels and transmission by buying and selling contracts for their sale or provision, as the case may be, in wholesale markets under limitations approved by EME's risk management committee. EMMT records these transactions in what it calls its proprietary book.

In conducting EME's hedging and trading activities, EMMT contracts with a number of utilities, energy companies and financial institutions. In the event a counterparty were to default on its trade obligation, EME would be exposed to the risk of possible loss associated with reselling the contracted product to another buyer at a lower price or having to purchase the contracted product from another supplier at a higher price if the non-performing counterparty were unable to pay the resulting liquidated damages owed to EME. Further, EME would be exposed to the risk of non-payment of accounts receivable accrued for products delivered prior to the time such counterparty defaulted.

To manage credit risk, EME looks at the risk of a potential default by its counterparties. Credit risk is measured by the loss EME would record if its counterparties failed to perform pursuant to the terms of their contractual obligations. EME has established controls to determine and monitor the creditworthiness of counterparties and uses master netting agreements whenever possible to mitigate its exposure to counterparty risk. EME requires counterparties to pledge collateral when deemed necessary. EME uses published credit ratings of counterparties and other publicly disclosed information, such as financial statements, regulatory filings and press releases, to guide it in the process of setting credit levels, risk limits and contractual arrangements, including master netting agreements. The credit quality of EME's counterparties is reviewed regularly by EME's risk management committee. In addition to continuously monitoring its credit exposure to its counterparties, EME also takes appropriate steps to limit or lower credit exposure. Despite this, there can be no assurance that EME's actions to mitigate risk will be wholly successful or that collateral pledged will be adequate.

EME's merchant power plants and energy trading activities expose EME to commodity price risks. Commodity price risks are actively monitored by EME's risk management committee to ensure compliance with EME's risk management policies. Policies are in place which define risk tolerances, and procedures exist which allow for monitoring of all commitments and positions with regular reviews by the risk management committee. EME uses "value at risk" to identify, measure, monitor and control its overall market risk exposure in respect of its Illinois Plants, its Homer City facilities and its proprietary positions. The use of value at risk allows management to aggregate overall commodity risk, compare risk on a consistent basis and identify risk factors. Value at risk measures the possible loss over a given time interval, under normal market conditions, at a given confidence level. Given the inherent limitations of value at risk and reliance on a single risk measurement tool, EME supplements this approach with the use of stress testing and worst-case scenario analysis for key risk factors, as well as stop-loss limits and counterparty credit exposure limits. Despite this, there can be no assurance that all risks have been accurately identified, measured and/or mitigated.

In executing agreements with counterparties to conduct hedging or trading activities, EME generally provides credit support when necessary through margining arrangements (agreements to provide or receive collateral, letters of credit or guarantees based on changes in the market price of the underlying contract under specific terms). To manage its liquidity, EME assesses the potential impact of future price changes in determining the amount of collateral requirements under existing or anticipated forward contracts. There is no assurance that EME's liquidity will be adequate to meet margin calls from counterparties in the case of extreme market changes or that the failure to meet such cash requirements would not have a material adverse effect on its liquidity. See "Risk Factors."

Significant Customers

In the past three fiscal years, EME derived a significant source of its operating revenues from electric power sold into the PJM market from the Homer City facilities and the Illinois Plants. Sales into PJM accounted for approximately 58%, 69% and 23% of EME's consolidated operating revenues for the years ended December 31, 2006, 2005 and 2004, respectively. For the year ended December 31, 2004, approximately 15% of EME's consolidated operating revenues generated at the Homer City facilities and Illinois Plants was from sales to BP Energy Company, a third-party customer. In 2004, EME also derived a significant source of its revenues from the sale of energy and capacity generated at the Illinois Plants to Exelon Generation primarily under three power purchase agreements. These power purchase agreements had all expired by the end of 2004. Exelon Generation accounted for approximately 35% of EME's consolidated operating revenues for the year ended December 31, 2004.

Insurance

EME maintains insurance policies consistent with those normally carried by companies engaged in similar business and owning similar properties. EME's insurance program includes all-risk property insurance, including business interruption, covering real and personal property, including losses from boilers, machinery breakdowns, and the perils of earthquake and flood, subject to specific sublimits. EME also carries general liability insurance covering liabilities to third parties for bodily injury or property damage resulting from operations, automobile liability insurance and excess liability insurance. Limits and deductibles in respect of these insurance policies are comparable to those carried by other electric generating facilities of similar size. However, no assurance can be given that EME's insurance will be adequate to cover all losses.

The Homer City property insurance program currently covers losses up to $1.1 billion. Under the terms of the participation agreements entered into on December 7, 2001 as part of the sale-leaseback transaction of the Homer City facilities, EME Homer City is required to maintain specified minimum insurance coverages if and to the extent that such insurance is available on a commercially reasonable basis. Although the insurance covering the Homer City facilities is comparable to insurance coverages normally carried by companies engaged in similar businesses, and owning similar properties, the insurance coverages that are in place do not meet the minimum insurance coverages required under the participation agreements. Due to the current market environment, the minimum insurance coverage is not commercially available at reasonable prices. EME Homer City has obtained a waiver under the participation agreements which permits it to maintain its current insurance coverage through June 1, 2007.

Seasonality

Due to higher electric demand resulting from warmer weather during the summer months and cold weather during the winter months, electric revenues from the Illinois Plants and the Homer City facilities vary substantially on a seasonal basis. In addition, maintenance outages generally are scheduled during periods of lower projected electric demand (spring and fall) further reducing generation and increasing major maintenance costs which are recorded as an expense when incurred. Accordingly, earnings from the Illinois Plants and the Homer City facilities are seasonal and have significant variability from quarter to quarter. Seasonal fluctuations may also be affected by changes in market prices. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Market Risk Exposures—Commodity Price Risk—Energy Price Risk Affecting Sales from the Illinois Plants" and "—Energy Price Risk Affecting Sales from the Homer City Facilities" for further discussion regarding market prices.

EME's third quarter equity in income from its energy projects is materially higher than equity in income related to other quarters of the year due to warmer weather during the summer months and because a number of EME's energy projects located on the West Coast have power sales contracts that provide for higher payments during the summer months.

Discontinued Operations

During 2004 and early 2005, EME sold assets totaling 6,452 MW, which constituted most of its international assets. Except for the Doga project, which was not sold, these international assets are accounted for as discontinued operations in accordance with SFAS No. 144 and, accordingly, all prior periods have been restated to reclassify the results of operations and assets and liabilities as discontinued operations. The sale of the international operations included:

- On September 30, 2004, EME sold its 51.2% interest in Contact Energy Limited to Origin Energy New Zealand Limited.

- On December 16, 2004, EME sold the stock and related assets of MEC International B.V. to IPM. The sale of MEC International included the sale of EME's ownership interests in ten electric power generating projects or companies located in Europe, Asia, Australia, and Puerto Rico.
- On January 10, 2005, EME sold its 50% equity interest in the Caliraya-Botocan-Kalayaan (CBK) hydroelectric power project located in the Philippines to CBK Projects B.V.
- On February 3, 2005, EME sold its 25% equity interest in the Tri Energy project to IPM.

See "Item 8. Financial Statements and Supplementary Data—Edison Mission Energy and Subsidiaries Notes to Consolidated Financial Statements—Note 5. Divestitures" for further details of discontinued operations.

Regulatory Matters

General

EME's operations are subject to extensive regulation by governmental agencies. EME's operating projects are subject to energy, environmental and other governmental laws and regulations at the federal, state and local levels in connection with the ownership and operation of its projects, and the use of electric energy, capacity and related products, including ancillary services from its projects. Federal laws and regulations govern, among other things, transactions by and with purchasers of power, including utility companies, the operation of a power plant and the ownership of a power plant. Under limited circumstances where exclusive federal jurisdiction is not applicable or specific exemptions or waivers from state or federal laws or regulations are otherwise unavailable, federal and/or state utility regulatory commissions may have broad jurisdiction over non-utility owned electric power plants. Energy-producing projects are also subject to federal, state and local laws and regulations that govern the geographical location, zoning, land use and operation of a project. Federal, state and local environmental requirements generally require that a wide variety of permits and other approvals be obtained before the commencement of construction or operation of an energy-producing facility and that the facility then operate in compliance with these permits and approvals.

EME is subject to a varied and complex body of laws and regulations that are in a state of flux. Intricate and changing environmental and other regulatory requirements could necessitate substantial expenditures and could create a significant risk of expensive delays or significant loss of value in a project if it were to become unable to function as planned due to changing requirements or local opposition.

U.S. Federal Energy Regulation

The FERC has ratemaking jurisdiction and other authority with respect to interstate wholesale sales and transmission of electric energy (other than transmission that is "bundled" with retail sales) under the Federal Power Act and with respect to certain interstate sales, transportation and storage of natural gas under the Natural Gas Act of 1938. Prior to February 8, 2006, the Securities and Exchange Commission had regulatory powers with respect to upstream owners of electric and natural gas utilities under PUHCA 1935, which was repealed as of that date by EPAct 2005. The enactment of PURPA and the adoption of regulations under PURPA by the FERC provided incentives for the development of cogeneration facilities and small power production facilities using alternative or renewable fuels by establishing certain exemptions from the Federal Power Act and PUHCA 1935 for the owners of qualifying facilities. The passage of the Energy Policy Act in 1992 further encouraged independent power production by providing additional exemptions from PUHCA 1935 for EWGs and foreign utility companies.

The Energy Policy Act of 2005

A comprehensive energy bill was passed by the U.S. House and Senate in July 2005 and was signed by President Bush on August 8, 2005. Known as "EPAct 2005," this comprehensive legislation includes provisions for the repeal of PUHCA 1935 and amendments to PURPA, for merger review reform, for the introduction of new regulations regarding "Transmission Operation Improvements," for FERC authority to impose civil penalties for violation of its regulations, for transmission rate reform, for incentives for various generation technologies and for the extension through December 31, 2007 of production tax credits for wind and other specified types of generation.

The FERC has finalized rules to implement the congressionally mandated repeal of PUHCA 1935, effective February 8, 2006, and enactment of PUHCA 2005. The repeal of PUHCA 1935 and its replacement by PUHCA 2005 effectively eliminates many of the restrictions on outside investment in the electricity industry, investment by and transactions between utilities, and geographic constraints on utility systems. PUHCA 1935 repeal is expected to enable investment in utility systems by private equity funds, financial institutions, foreign utility companies, and other non-utility companies without the burden of registration as a "public utility holding company." It also eliminates limits on investment in non-utility operations companies that were registered holding companies under PUHCA 1935, subject to other applicable regulatory limitations, as well as geographic limits on potential utility combinations. PUHCA 2005 is primarily a "books and records access" statute and does not give the FERC any new substantive authority under the Federal Power Act or Natural Gas Act. The FERC has also issued final rules to implement the electric company merger and acquisition provisions of EPAct 2005.

Federal Power Act

The Federal Power Act grants the FERC exclusive jurisdiction over the rates, terms and conditions of wholesale sales of electricity and transmission services in interstate commerce (other than transmission that is "bundled" with retail sales), including ongoing, as well as initial, rate jurisdiction. This jurisdiction allows the FERC to revoke or modify previously approved rates after notice and opportunity for hearing. These rates may be based on a cost-of-service approach or, in geographic and product markets determined by the FERC to be workably competitive, may be market based. Most qualifying facilities, as that term is defined in PURPA, are exempt from the ratemaking and several other provisions of the Federal Power Act. EWGs certified in accordance with the FERC's rules under PUHCA 2005 and other non-qualifying facility independent power projects are subject to the Federal Power Act and to the FERC's ratemaking jurisdiction thereunder, but the FERC typically grants EWGs the authority to charge market-based rates to purchasers which are not affiliated electric utility companies as long as the absence of market power is shown. In addition, the Federal Power Act grants the FERC jurisdiction over the sale or transfer of jurisdictional facilities, including wholesale power sales contracts and, after EPAct 2005, generation facilities, and in some cases, jurisdiction over the issuance of securities or the assumption of specified liabilities and some interlocking directorates. In granting authority to make sales at market-based rates, the FERC typically also grants blanket approval for certain obligations, such as those related to the issuance of securities.

As of December 31, 2006, a number of EME's operating projects, including the Homer City facilities and the Illinois Plants, were subject to the FERC ratemaking regulation under the Federal Power Act. EME's future domestic non-qualifying facility independent power projects will also be subject to the FERC jurisdiction on rates.

PJM Reliability Pricing Model—

On August 31, 2005, PJM filed under sections 205 and 206 of the Federal Power Act a proposal for a RPM to replace its existing construct for the purchase and sale of capacity. PJM's proposal offered RPM as a way to address deficiencies in PJM's current structure in a comprehensive and integrated manner. On April 20, 2006, the FERC issued an Initial Order on RPM, finding PJM's existing capacity construct to be unjust and unreasonable as a long-term capacity solution, because it fails to set prices adequate to ensure energy resources to meet PJM's reliability responsibilities. Although the FERC did not find the RPM proposal, as filed by PJM, to be a just and reasonable replacement for the current capacity construct, because some elements of the proposal need further development and elaboration, it did find that certain elements of the RPM proposal, with some adjustment and clarification, could form the basis for a just and reasonable capacity market. Accordingly, in the order the FERC provided guidance on PJM's RPM proposal, noted other features that need to be included in a just and reasonable capacity market, and established further proceedings to resolve these issues. On September 29, 2006, a comprehensive settlement agreement among PJM and many of its stakeholders, including EME, embodying a proposed capacity market construct for PJM, was submitted to the FERC for approval. On December 22, 2006, the FERC issued an order conditionally approving the RPM settlement. EME continues to review and evaluate the FERC order, but believes at this time that the implementation of the settlement will benefit the Illinois Plants and the Homer City facilities.

FERC Order Regarding PJM Marginal Losses—

On May 1, 2006, the FERC issued an order in response to a complaint filed by Pepco Holdings, Inc. against PJM regarding marginal losses for transmission. The FERC concluded that PJM had violated its tariff by not implementing marginal losses and further directed PJM to implement marginal losses by October 2, 2006. On June 19, 2006, the FERC issued an order delaying implementation of marginal losses in PJM until June 1, 2007. On August 3, 2006, PJM filed its Tariff and Operating Agreement changes to implement marginal losses. On November 6, 2006, the FERC issued an order accepting those Tariff and Operating Agreement changes.

Implementation of marginal losses will adjust the algorithm that calculated locational marginal prices to include a component for marginal transmission losses in addition to the already included component for congestion. This may reduce market prices for sellers in the Western PJM and Northern Illinois regions, including the Homer City facilities and the Illinois Plants.

Public Utility Regulatory Policies Act of 1978

PURPA provides two primary benefits to qualifying facilities. First, all cogeneration facilities that are qualifying facilities are exempt from certain provisions of the Federal Power Act and regulations of the FERC thereunder. Second, the FERC regulations promulgated under PURPA require that electric utilities purchase electricity generated by qualifying facilities at a price based on the purchasing utility's avoided cost (unless, pursuant to EPAct 2005, the FERC determines that the relevant market meets certain conditions for competitive, nondiscriminatory access), and that the utilities sell back up power to the qualifying facility on a nondiscriminatory basis. The FERC's regulations also permit qualifying facilities and utilities to negotiate agreements for utility purchases of power at prices different from the utility's avoided costs. While it had been common for utilities to enter into long-term contracts with qualifying facilities in order, among other things, to facilitate project financing of independent power facilities and to reflect the deferral by the utility of capital costs for new plant additions, increasing competition and the development of new power markets have resulted in a trend toward shorter term power contracts that would place greater risk on the project owner.

If one of the projects in which EME has an interest were to lose its status as a qualifying cogeneration facility, the project would no longer be entitled to the qualifying facility-related exemptions from regulation. As a result, the project could become subject to rate regulation by the FERC under the Federal Power Act and additional state regulation. Loss of qualifying facility status could also trigger defaults under covenants to maintain qualifying facility status in the project's power sales agreements, steam sales agreements and financing agreements and result in termination, penalties or acceleration of indebtedness under such agreements. If a power purchaser were to cease taking and paying for electricity or were to seek to obtain refunds of past amounts paid because of the loss of qualifying facility status, EME cannot provide assurance that the costs incurred in connection with the project could be recovered through sales to other purchasers. Moreover, EME's business and financial condition could be adversely affected if regulations or legislation were modified or enacted that changed the standards applicable to EME's facilities for maintaining qualifying facility status or that eliminated or reduced the benefits and exemptions currently enjoyed by EME's qualifying facilities. Loss of qualifying facility status on a retroactive basis could lead to, among other things, fines and penalties, or claims by a utility customer for the refund of payments previously made.

EPAct 2005 made several important amendments to PURPA, including the elimination of qualifying facility ownership restrictions, elimination of the requirement that electric utilities enter into new contracts to purchase electricity from qualifying facilities that have access to wholesale power markets that meet specified criteria or sell energy to existing qualifying facilities in states where there is retail electricity competition and no obligation under state law to make power sales, the granting of new authority to the FERC to ensure recovery by electric utilities of all prudently incurred costs associated with purchases of energy and capacity from qualifying facilities, and certain obligations upon electric utilities for interconnection and metering for qualifying facilities. The FERC has initiated several proceedings to promulgate rules and regulations to implement the mandates of EPAct 2005 with respect to PURPA, and EME is continuing to evaluate the effect of the legislation and proposed regulations on its business activities.

EME endeavors to monitor regulatory compliance by its qualifying facility projects in a manner that minimizes the risks of losing these projects' qualifying facility status. However, some factors necessary to maintain qualifying facility status are subject to risks of events outside EME's control. For example, loss of a thermal energy customer or failure of a thermal energy customer to take required amounts of thermal energy from a cogeneration facility that is a qualifying facility could cause a facility to fail to meet the requirements regarding the minimum level of useful thermal energy output. Upon the occurrence of this type of event, EME would seek to replace the thermal energy customer or find another use for the thermal energy that meets the requirements of PURPA.

Natural Gas Act

Many of the operating facilities that EME owns, operates or has investments in use natural gas as their primary fuel. Under the Natural Gas Act, the FERC has jurisdiction over certain sales of natural gas and over transportation and storage of natural gas in interstate commerce. The FERC has granted blanket authority to all persons to make sales of natural gas without restriction but continues to exercise significant oversight with respect to transportation and storage of natural gas services in interstate commerce.

Transmission of Wholesale Power

Generally, projects that sell power to wholesale purchasers other than the local utility to which the project is interconnected require the transmission of electricity over power lines owned by others. This transmission service over the lines of intervening transmission owners is also known as wheeling. The prices and other terms and conditions of transmission contracts are regulated by the FERC when the entity providing the transmission service is a jurisdictional public utility under the Federal Power Act.

The Energy Policy Act of 1992 laid the groundwork for a competitive wholesale market for electricity by, among other things, expanding the FERC's authority to order electric utilities to transmit third-party electricity over their transmission lines, thus allowing qualifying facilities under PURPA, power marketers and those qualifying as EWGs under PUHCA 1935 to more effectively compete in the wholesale market.

In 1996, the FERC issued Order No. 888, also known as the Open Access Rules, which require utilities to offer eligible wholesale transmission customers open access on utility transmission lines on a comparable basis to the utilities' own use of the lines and directed jurisdictional public utilities that control a substantial portion of the nation's electric transmission networks to file uniform, non-discriminatory open access tariffs containing the terms and conditions under which they would provide such open access transmission service. The FERC subsequently issued Order Nos. 888-A, 888-B and 888-C to clarify the terms that jurisdictional transmitting utilities are required to include in their open access transmission tariffs and Order No. 889, which required those transmitting utilities to abide by specified standards of conduct when using their own transmission systems to make wholesale sales of power, and to post specified transmission information, including information about transmission requests and availability, on a publicly available computer bulletin board.

On February 15, 2007, the FERC issued Order No. 890 with the stated intent of promoting competition in wholesale power markets and strengthening the electric power grids. Order No. 890 is designed to strengthen the Open Access Rules embodied in Order No. 888, increase transparency in the rules applicable to planning and use of the transmission system, make undue discrimination in transmission easier to detect, and facilitate the FERC's enforcement efforts in remedying such discrimination. Public utility transmission providers, including RTOs and ISOs, are required to make changes in their tariffs to comply with Order No. 890. Order No. 890 will take effect within 60 days of its publication in the Federal Register, which is expected to occur within 30 days of its issuance.

See "Overview of Facilities—Illinois Plants—Transmission" for further discussion of developments and other transmission issues affecting the Illinois Plants.

Environmental Matters and Regulations

See the discussion on environmental matters and regulations in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Environmental Matters and Regulations."

Employees

At December 31, 2006, EME and its subsidiaries employed 1,751 people, including:

- approximately 732 employees at the Illinois Plants covered by a collective bargaining agreement governing wages, certain benefits and working conditions. This collective bargaining agreement will expire on December 31, 2009. Midwest Generation also has a separate collective bargaining agreement governing retirement, health care, disability and insurance benefits that expired on June 15, 2006. Despite extensive negotiations, Midwest Generation and Local 15 were not able to reach agreement on changes in this benefits agreement. Midwest Generation will continue to provide benefits under the expired agreement until a determination is made to implement the proposed new terms over which the parties are at impasse; and

- approximately 196 employees at the Homer City facilities covered by a collective bargaining agreement governing wages, benefits and working conditions. This collective bargaining agreement, which expired on December 31, 2006, was extended to December 31, 2007 by mutual agreement.

EME's Relationship with Certain Affiliated Companies

EME is an indirect subsidiary of Edison International. Edison International is a holding company. Edison International is also the corporate parent of SCE, an electric utility that serves customers in California.

MEHC

On June 8, 2001, Edison International created MEHC as a wholly owned indirect subsidiary. MEHC's principal asset is EME's common stock. During 2001, MEHC issued $800 million of 13.50% senior secured notes due 2008. The senior secured notes are secured by a first priority security interest in EME's common stock. Any foreclosure on the pledge of EME's common stock by the holders of the senior secured notes could result in a change in control of EME. A change in control of EME could trigger an obligation of Midwest Generation to repurchase its outstanding senior secured notes at 101% of the aggregate principal amount of notes repurchased, plus accrued and unpaid interest and liquidated damages, if any, and could result in an event of default under Midwest Generation's secured term loan facility. This relationship is discussed further in "Item 8. Financial Statements and Supplementary Data—Edison Mission Energy and Subsidiaries Notes to Consolidated Financial Statements—Note 1. Summary of Significant Accounting Policies."

ITEM 1A. RISK FACTORS

EME has substantial interests in merchant energy power plants which are subject to market risks related to wholesale energy prices.

EME's merchant energy power plants do not have long-term power purchase agreements. Because the output of these power plants is not committed to be sold under long-term contracts, these projects are subject to market forces which determine the amount and price of energy, capacity and ancillary services sold from the power plants. The factors that influence the market price for energy, capacity and ancillary services include:

- prevailing market prices for coal, natural gas and fuel oil, and associated transportation;
- the extent of additional supplies of capacity, energy and ancillary services from current competitors or new market entrants, including the development of new generation facilities or technologies that may be able to produce electricity at a lower cost than EME's generating facilities and/or increased access by competitors to EME's markets as a result of transmission upgrades;
- transmission congestion in and to each market area and the resulting differences in prices between delivery points;
- the market structure rules established for each market area and regulatory developments affecting the market areas, including any price limitations and other mechanisms adopted to address volatility or illiquidity in these markets or the physical stability of the system;

- the cost and availability of emission credits or allowances;
- the availability, reliability and operation of competing power generation facilities, including nuclear generating plants where applicable, and the extended operation of such facilities beyond their presently expected dates of decommissioning;
- weather conditions prevailing in surrounding areas from time to time; and
- changes in the demand for electricity or in patterns of electricity usage as a result of factors such as regional economic conditions and the implementation of conservation programs.

In addition, unlike most other commodities, electric power can only be stored on a very limited basis and generally must be produced concurrently with its use. As a result, the wholesale power markets are subject to significant and unpredictable price fluctuations over relatively short periods of time.

There is no assurance that EME's merchant energy power plants will be successful in selling power into their markets or that the prices received for their power will generate positive cash flows. If EME's merchant energy power plants do not meet these objectives, they may not be able to generate enough cash to service their own debt and lease obligations, which could have a material adverse effect on EME.

EME's financial results can be affected by changes in fuel prices, fuel transportation cost increases, and interruptions in fuel supply.

EME's business is subject to changes in fuel costs, which may negatively affect its financial results and financial position by increasing the cost of producing power. The fuel markets can be volatile, and actual fuel prices can differ from EME's expectations.

Although EME attempts to purchase fuel based on its known fuel requirements, it is still subject to the risks of supply interruptions, transportation cost increases, and fuel price volatility. In addition, fuel deliveries may not exactly match energy sales, due in part to the need to purchase fuel inventories in advance for reliability and dispatch requirements. The price at which EME can sell its energy may not rise or fall at the same rate as a corresponding rise or fall in fuel costs. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Market Risk Exposures—Commodity Price Risk."

EME may not be able to hedge market risks effectively.

EME is exposed to market risks through its ownership and operation of merchant energy power plants and through its power marketing business. These market risks include, among others, volatility arising from the timing differences associated with buying fuel, converting fuel into energy and delivering energy to a buyer. EME uses forward contracts and derivative financial instruments, such as futures contracts and options, to manage market risks and exposure to fluctuating electricity and fuel prices. However, EME cannot provide assurance that these strategies will successfully mitigate market risks, or that they will not result in net losses.

EME may not cover the entire exposure of its assets or positions to market price volatility, and the level of coverage will vary over time. Fluctuating commodity prices may negatively affect EME's financial results to the extent that assets and positions have not been hedged.

The effectiveness of EME's hedging activities may depend on the amount of working capital available to post as collateral in support of these transactions, either in support of performance guarantees or as a cash margin. The amount of credit support that must be provided typically is based on the difference between the price of the commodity in a given contract and the market price of the commodity. Significant movements in market prices can result in a requirement to provide cash collateral and letters of credit in very large amounts. Without adequate liquidity to meet margin and collateral requirements, EME could be exposed to the following:

- a reduction in the number of counterparties willing to enter into bilateral contracts, which would result in increased reliance on short-term and spot markets instead of bilateral contracts, increasing EME's exposure to market volatility; and
- a failure to meet a margining requirement, which could permit the counterparty to terminate the related bilateral contract early and demand immediate payment for the replacement value of the contract.

As a result of these and other factors, EME cannot predict with precision the effect that risk management decisions may have on its businesses, operating results or financial position. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Margin, Collateral Deposits and Other Credit Support for Energy Contracts."

EME is exposed to credit and performance risk from third parties under supply and transportation contracts.

EME relies on contracts for the supply and transportation of fuel and other services required for the operation of its generation facilities. EME's operations are exposed to the risk that counterparties will not perform their obligations. If a counterparty failed to perform under a contract, EME would need to obtain alternate suppliers or alternate means of transportation for its requirements of fuel or other services, which could result in higher costs or disruptions in its operations. Furthermore, EME is exposed to credit risk because damages related to a breach of contract may not be recoverable. Accordingly, the failure of a supplier to fulfill its contractual obligations could have a material adverse effect on EME's financial results.

EME is subject to extensive energy industry regulation.

EME's operations are subject to extensive regulation by governmental agencies. EME's projects are subject to federal laws and regulations that govern, among other things, transactions by and with purchasers of power, including utility companies, the development and construction of generation facilities, the ownership and operations of generation facilities, and access to transmission. Under limited circumstances where exclusive federal jurisdiction is not applicable or specific exemptions or waivers from state or federal laws or regulations are otherwise unavailable, federal and/or state utility regulatory commissions may have broad jurisdiction over non-utility owned electric power plants. Generation facilities are also subject to federal, state and local laws and regulations that govern, among other things, the geographical location, zoning, land use and operation of a project. See "Regulatory Matters."

The FERC may impose various forms of market mitigation measures, including price caps and operating restrictions, where it determines that potential market power might exist and that the public interest requires mitigation. In addition, many of EME's facilities are subject to rules, restrictions and terms of participation imposed and administered by various RTOs and ISOs. For example, ISOs and RTOs may impose bidding and scheduling rules, both to curb the potential exercise of market power and to facilitate market functions. Such actions may materially affect EME's results of operations.

There is no assurance that the introduction of new laws or other future regulatory developments will not have a material adverse effect on EME's business, results of operations or financial condition, nor is there any assurance that EME will be able to obtain and comply with all necessary licenses, permits and approvals for its projects. If projects cannot comply with all applicable regulations, EME's business, results of operations and financial condition could be adversely affected.

EME is subject to extensive environmental regulation and permitting requirements that involve significant and increasing costs.

EME's operations are subject to extensive environmental regulations with respect to, among other things, air quality, water quality, waste disposal, and noise. EME is required to comply with these regulations, as well as conditions established by licenses, permits and other approvals, in order to construct, operate or modify its facilities. Failure to comply with these requirements could subject EME to civil or criminal liability, the imposition of liens or fines, or actions by regulatory agencies seeking to curtail EME's operations.

EME devotes significant resources to environmental monitoring, pollution control equipment and emission allowances to comply with environmental regulatory requirements. EME believes that it is currently in substantial compliance with environmental regulatory requirements. However, the current trend is toward more stringent standards, stricter regulation, and more expansive application of environmental regulations. Environmental advocacy groups and regulatory agencies in the United States have been focusing considerable attention on carbon dioxide emissions from coal-fired power plants and their potential role in climate change. The adoption of laws and regulations to implement carbon dioxide controls could adversely affect EME's coal-fired plants. Also, coal plant emissions of NO_X and SO_2, mercury and particulates are subject to increased controls and mitigation expenses. Additionally, certain of the states in which EME operates are contemplating air pollution control regulations that are more stringent than existing and proposed federal regulations. The continued operation of EME's facilities, particularly its coal-fired facilities, will require substantial capital expenditures for environmental controls.

For example, in December 2006, Midwest Generation entered into an agreement with the Illinois EPA to reduce mercury, NO_x and SO_2 emissions at Midwest Generation's Illinois coal-fired power plants. Capital expenditures relating to controls contemplated by the agreement are expected (in 2006 dollars) to be in the range of approximately \$2.7 billion to \$3.4 billion through 2018. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Environmental Matters and Regulations—Air Quality Regulation—Clean Air Act—Illinois." There is no assurance that these capital expenditures will not exceed the above estimates.

In addition, future environmental laws and regulations, and future enforcement proceedings that may be taken by environmental authorities, could affect the costs and the manner in which EME conducts its business. There is no assurance that EME would be able to recover these increased costs from its customers or that its business, financial position and results of operations would not be materially adversely affected. Furthermore, changing environmental regulations could make some units uneconomical to maintain or operate. If EME cannot comply with all applicable regulations, it could be required to retire or suspend operations at its facilities, or restrict or modify the operations of its facilities, and its business, results of operations and financial condition could be adversely affected.

Typically, environmental laws require a lengthy and complex process for obtaining licenses, permits and approvals prior to construction, operation or modification of a project or generating facility. Meeting all the necessary requirements can delay or sometimes prevent the completion of a proposed project as well as require extensive modifications to existing projects, which may involve significant capital expenditures. EME cannot provide assurance that it will be able to obtain and comply with all necessary licenses, permits and approvals for its plants. If there is a delay in obtaining required approvals or permits or if EME fails to obtain and comply with such permits, the operation of EME's facilities may be interrupted or become subject to additional costs.

EME's development projects or future acquisitions may not be successful.

EME's future financial condition, results of operation and cash flows will depend in large part upon its ability to successfully implement its long-term strategy, which includes the development and acquisition of electric power generation facilities, with an emphasis on renewable energy (primarily wind) and gas-fired power plants. EME may be unable to identify attractive acquisition or development opportunities and/or to complete and integrate them on a successful and timely basis. Furthermore, implementation of this strategy may be affected by factors beyond EME's control, such as increased competition, legal and regulatory developments, price volatility in electric or fuel markets, and general economic conditions.

In support of its development activities, EME has entered into commitments of $489 million to purchase turbines for future projects and plans to make substantial additional commitments in the future. In addition, EME expends significant amounts for preliminary engineering, permitting, legal and other expenses before it can determine whether it will win a competitive bid, or whether a project is feasible or economically attractive.

EME's development activities are subject to risks including, without limitation, risks related to project siting, financing, construction, permitting, and governmental approvals. EME may not be successful in developing new projects or the timing of such development may be delayed beyond the date such turbines are ready for installation. Furthermore, EME may not be able to obtain financing for new projects that are developed and may not be able to obtain sufficient equity capital or additional borrowings to enable it to fund equity commitments for future projects. If a project under development is abandoned, EME would expense all capitalized costs incurred in connection with that project, and could incur additional losses associated with any related contingent liabilities. If EME is not successful in developing new projects, it may be required to sell turbines that were purchased and such sales may result in substantial losses. For example, in February 2007, EME was advised that it was an unsuccessful bidder in the request for offers conducted by SCE for the supply of generation capacity. EME plans to use the turbines which it had purchased and reserved for this bid for other generation supply opportunities, although there is no assurance that these efforts will be successful. For further discussion, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Contractual Obligations, Contingencies and Commitments—Purchase Obligations."

Finally, EME cannot provide assurance that its development projects or acquired assets will generate sufficient cash flow to support the indebtedness incurred to acquire them or the capital expenditures needed to develop them, or that the rate of return from such projects or assets will be sufficient to justify the decision to invest in them.

Competition could adversely affect EME's business.

The independent power industry is characterized by numerous capable competitors, some of whom may have more extensive operating experience in the acquisition and development of power projects, larger staffs, and greater financial resources than EME. Several participants in the wholesale markets, including many regulated utilities, have a lower cost of capital than most merchant generators and often are able to recover fixed costs through rate base mechanisms, allowing them to build, buy and upgrade generation assets without relying exclusively on market clearing prices to recover their investments. This could affect EME's ability to compete effectively in the markets in which those entities operate.

Newer plants owned by EME's competitors are often more efficient than EME's facilities. This may put some of EME's facilities at a competitive disadvantage to the extent that its competitors are able to produce more power from each increment of fuel than EME's facilities are capable of producing. Over time, some of EME's facilities may become obsolete in their markets, or be unable to compete, because of the construction of newer, more efficient power plants.

In addition to the competition already existing in the markets in which EME presently operates or may consider operating in the future, EME is likely to encounter significant competition as a result of further consolidation of the power industry by mergers and asset reallocations, which could create powerful new competitors, and new market entrants such as investment companies. In addition, the EPAct 2005 and other regulatory initiatives may result in changes in the power industry to which EME may not be able to respond in as timely and effective manner as its competitors.

EME's parent, MEHC, depends upon cash flows from EME to service its debt.

The principal asset of MEHC is the common stock of EME. In July 2001, MEHC issued $800 million of 13.50% senior secured notes due 2008. These senior secured notes are secured by a first priority security interest in EME's common stock. Any foreclosure on the pledge of EME's common stock by the holders of the senior secured notes would result in a change in control of EME which could have a material adverse effect on EME. Dividends from EME are limited based on its earnings and cash flow, the terms of restrictions contained in EME's corporate credit facility, business and tax considerations and restrictions imposed by applicable law. For a discussion of contractual restrictions that could constrain the ability of EME's subsidiaries to pay dividends or distributions to EME, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Dividend Restrictions in Major Financings."

EME may not be able to raise capital on favorable terms, to refinance existing EME or subsidiary indebtedness or to fund operations, capital expenditures, future acquisitions and development activities, which could adversely affect its results of operations.

The factors that influence EME's ability to arrange for financing and its costs of capital include:

- general economic and capital market conditions;
- the availability of bank credit;
- investor confidence;
- the financial condition, performance, prospects, and credit rating of EME and/or the subsidiary requiring the financing; and
- changes in tax and securities laws.

While EME believes that its sources of capital will be adequate to meet its obligations for the foreseeable future, this belief is based on a number of material assumptions, including without limitation assumptions about EME's ability to access the capital and commercial lending markets, the operating and financial performance of EME's subsidiaries, and the ability of EME's subsidiaries to pay dividends. Any of these assumptions could prove to be incorrect. EME cannot provide assurance that its projected sources of capital will be available when needed or that its actual cash requirements will not be greater than expected.

EME and its subsidiaries have a substantial amount of indebtedness, including long-term lease obligations.

As of December 31, 2006, EME's consolidated debt was $3.2 billion. In addition, EME's subsidiaries have $4.2 billion of long-term power plant lease obligations that are due over a period ranging up to 28 years. The substantial amount of consolidated debt and financial obligations presents the risk that EME and its subsidiaries might not have sufficient cash to service their indebtedness or long-term lease obligations and that the existing corporate debt, project debt and lease obligations could limit the ability of EME and its subsidiaries to grow their business, to compete effectively, to operate successfully under adverse economic conditions, or to plan for and react to business and industry changes. If EME's or a subsidiary's cash flows and capital resources were insufficient to allow it to make scheduled payments on its debt, EME or its subsidiaries might have to reduce or delay capital expenditures, sell assets, seek additional capital, or restructure or refinance the debt. The terms of EME's or its subsidiaries' debt may not allow these alternative measures, the debt or equity may not be available on acceptable terms, and these alternative measures may not satisfy all scheduled debt service obligations.

The ability of EME's largest subsidiary, Midwest Generation, to make distributions is restricted.

Midwest Generation, which owns or leases EME's fossil fuel plants located in Illinois, has entered into financing documents that contain restrictions on its ability to pay dividends. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

EME is the guarantor of the Powerton and Joliet (Units 7 and 8) leases and is obligated under intercompany notes to make debt service payments to Midwest Generation. Each intercompany note is a general corporate obligation of EME, and payments on it are made from distributions from subsidiaries and other sources of cash received by EME. Accordingly, EME must continue to make payments under the intercompany notes regardless of whether or not Midwest Generation makes distributions to EME. If EME were not able to satisfy its obligations under the intercompany notes, it would result in a default under the financing documents of EME and Midwest Generation. This could have a material adverse effect on the results of operations and cash flows of EME.

Restrictions in EME's certificate of incorporation, its credit facilities and the MEHC financing documents limit the ability of EME and its subsidiaries to enter into specified transactions that they otherwise may enter into and may significantly impede their ability to refinance their debt or borrow additional funds.

The financing documents entered into by MEHC contain financial and investment covenants restricting EME and its subsidiaries. EME's certificate of incorporation binds it to the provisions in MEHC's financing documents by restricting EME's ability to enter into specified transactions and engage in specified business activities without shareholder approval. The instruments governing EME's indebtedness also contain financial and investment covenants. Restrictions contained in these documents could affect, and in some cases significantly limit or prohibit, EME and its subsidiaries' ability to, among other things, incur, refinance, and prepay debt, make capital expenditures, pay dividends and make other distributions, make investments, create liens, sell assets, enter into sale and leaseback transactions, issue equity interests, enter into transactions with affiliates, create restrictions on the ability to pay dividends or make other distributions and engage in mergers and consolidations. These restrictions may significantly impede the ability of EME and its subsidiaries to take advantage of business opportunities as they arise, to grow their business and compete effectively, or to develop and implement any refinancing plans in respect of their indebtedness. See "—EME and its subsidiaries have a substantial amount of indebtedness, including long-term lease obligations," for further discussion.

In addition, in connection with the entry into new financings or amendments to existing financing arrangements, EME's and its subsidiaries' financial and operational flexibility may be further reduced as a result of more restrictive covenants, requirements for security and other terms that are often imposed on sub-investment grade entities.

EME's projects may be affected by general operating risks and hazards customary in the power generation industry. EME may not have adequate insurance to cover all these hazards.

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

- performance below expected levels of output or efficiency;
- interruptions in fuel supply;
- disruptions in the transmission of electricity;
- curtailment of operations due to transmission constraints;
- breakdown or failure of equipment or processes;
- imposition of new regulatory, permitting, or environmental requirements, or violations of existing requirements;
- employee work force factors, including strikes, work stoppages or labor disputes;
- operator/contractor error; and
- catastrophic events such as terrorist activities, fires, tornadoes, earthquakes, explosions, floods or other similar occurrences affecting power generation facilities or the transmission and distribution infrastructure over which power is transported.

These and other hazards can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, contamination of or damage to the environment, and suspension of operations. The occurrence of one or more of the events listed above could decrease or eliminate revenues generated by EME's projects or significantly increase the costs of operating them, and could also result in EME being named as a defendant in lawsuits asserting claims for substantial damages, potentially including environmental cleanup costs, personal injury, property damage, fines and penalties. Equipment and plant warranties and insurance may not be sufficient or effective under all circumstances to cover lost revenues or increased expenses. A decrease or elimination in revenues generated by the facilities or an increase in the costs of operating them could decrease or eliminate funds available to meet EME's obligations as they become due and could have a material adverse effect on EME. A default under a financing obligation of a project entity could result in a loss of EME's interest in the project.

The accounting for EME's hedging and proprietary trading activities may increase the volatility of its quarterly and annual financial results.

EME engages in hedging activities in order to mitigate its exposure to market risk with respect to electricity sales from its generation facilities, fuel utilized by those facilities and emissions allowances. EME generally attempts to balance its fixed-price physical and financial purchases and sales commitments in terms of contract volumes and the timing of performance and delivery obligations through the use of financial and physical derivative contracts. EME also uses derivative contracts with respect to its limited proprietary trading activities, through which EME attempts to achieve incremental returns by transacting where it has specific market expertise. These derivative contracts are recorded on its balance sheet at fair value pursuant to SFAS No. 133. Some of these derivative contracts do not qualify under SFAS No. 133 for hedge accounting and changes in their fair value are therefore recognized currently in earnings as unrealized gains or losses. As a result, EME's financial results, including gross margin, operating income and balance sheet ratios, will at times be volatile and subject to fluctuations in value primarily due to changes in electricity and fuel prices. For a more detailed discussion of the accounting treatment of EME's hedging and proprietary trading activities, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Market Risk Exposures—Accounting for Energy Contracts."

ITEM 1B. UNRESOLVED STAFF COMMENTS

Inapplicable.

ITEM 2. PROPERTIES

EME leases its principal office in Irvine, California. The office lease is for approximately 60,000 square feet and expires on December 31, 2010. EME also leases office space in Chicago, Illinois; Chantilly, Virginia; Boston, Massachusetts; and Washington D.C. The Chicago lease is for approximately 41,000 square feet and expires on December 31, 2014. The Chantilly lease is for approximately 30,000 square feet and expires on March 31, 2010 and has been subleased since May 2001. The Boston lease is for approximately 37,000 square feet and expires on July 31, 2007. The Washington D.C. lease is immaterial.

The following table shows, as of December 31, 2006, the material properties owned or leased by EME's subsidiaries and affiliates. Each property represents at least five percent of EME's income before tax or is one in which EME has an investment balance greater than $50 million. Most of these properties are subject to mortgages or other liens or encumbrances granted to the lenders providing financing for the plant or project.

Description of Properties

Plant	Location	Interest In Land	Plant Description
Homer City	Pittsburgh, Pennsylvania	Owned	Coal-fired generation facility
Illinois Plants	Northeast Illinois	Owned	Coal, oil/gas-fired generation facilities
Sunrise	Fellows, California	Leased	Combined cycle generation facility
Sycamore	Oildale, California	Leased	Natural gas-turbine cogeneration facility
Watson	Carson, California	Leased	Natural gas-turbine cogeneration facility

ITEM 3. LEGAL PROCEEDINGS

FERC Notice Regarding Investigatory Proceeding against EMMT

At the end of October 2006, EMMT was advised by the enforcement staff at the FERC that it is prepared to recommend that the FERC initiate a formal investigatory proceeding and seek monetary sanctions against EMMT for alleged violation of the FERC's rules with respect to certain bidding practices employed by EMMT. EMMT is engaged in discussions with the staff to explore the possibility of resolution of this matter. Should a formal proceeding be commenced, EMMT will be entitled to contest any alleged violations before the FERC and an appropriate court. EME believes that EMMT has complied with the FERC's rules and intends to contest vigorously any allegation of violation. EME cannot predict at this time the outcome of this matter or estimate the possible liability should the outcome be adverse.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Inapplicable.

PART II

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

All the outstanding common stock of EME is, as of the date hereof, owned by MEHC, which is a wholly owned subsidiary of Edison Mission Group Inc., a wholly owned subsidiary of Edison International. There is no market for the common stock. Dividends on the common stock will be paid when declared by EME's board of directors. EME made cash dividend payments totaling $51 million in 2006, $360 million in 2005 and $74 million in 2004. A total of $26 million in dividends was paid in January 2007. Dividends from EME may be limited based on its earning and cash flow, terms of restrictions contained in EME's corporate credit facility, business and tax considerations, and restrictions imposed by applicable law. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Dividend Restrictions in Major Financings" for more information about dividend restrictions in EME's corporate credit facility.

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data was derived from EME's audited financial statements and is qualified in its entirety by the more detailed information and financial statements, including notes to these financial statements, included in this annual report. EME's international operations are accounted for as discontinued operations, except the Doga project in Turkey, which is accounted for as an equity investment. Continuing operations include EME's Illinois Plants and Homer City facilities, energy trading, power projects under contract, the Doga project, corporate interest expense and general and administrative expenses. In April 2006, EME received, as a capital contribution, ownership interests in a portfolio of wind projects located in Iowa and Minnesota and a small biomass project. These projects were previously owned by EME's affiliate, Edison Capital. EME accounted for this acquisition at Edison Capital's historical cost as a transaction between entities under common control for a net book value of approximately $76 million. The historical consolidated financial and operating results data reflects the acquisition as though EME had ownership of such projects for all periods presented. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Results of Continuing Operations" and "—Results of Discontinued Operations" for more information about the sale of EME's international operations and loss on lease termination, asset impairment and other charges in 2005 and 2004.

	Years Ended December 31,				
	2006	2005	2004	2003	2002
	(in millions)				
INCOME STATEMENT DATA					
Operating revenues	$ 2,239	$ 2,265	$ 1,653	$ 1,779	$ 1,713
Operating expenses					
Fuel, plant operations and plant operating lease	1,332	1,287	1,300	1,334	1,292
Depreciation and amortization	144	134	152	156	147
Loss on lease termination, asset impairment and other charges and credits	—	7	989	304	60
Administrative and general	140	154	149	138	118
	1,616	1,582	2,590	1,932	1,617
Operating income (loss)	623	683	(937)	(153)	96
Equity in income from unconsolidated affiliates	186	229	218	239	196
Impairment loss on equity method investment	—	(55)	—	—	—
Interest and other income	120	69	52	2	15
Interest expense	(279)	(300)	(298)	(303)	(313)
Loss on early extinguishment of debt	(146)	(4)	—	—	—
Income (loss) from continuing operations before income taxes and minority interest	504	622	(965)	(215)	(6)
Provision (benefit) for income taxes	189	208	(406)	(121)	(28)
Minority interest	1	—	(1)	(2)	(2)
Income (loss) from continuing operations	316	414	(560)	(96)	20
Income from operations of discontinued subsidiaries (including gain on disposal of $533 million in 2004), net of tax	98	29	690	124	22
Income before accounting change	414	443	130	28	42
Cumulative effect of change in accounting, net of tax(1)	—	(1)	—	(9)	(14)
Net income	$ 414	$ 442	$ 130	$ 19	$ 28

(1) The 2005 loss from a change in accounting principle resulted from the adoption of a new accounting standard for conditional asset retirements. The 2003 loss from a change in accounting principle resulted from adoption of a new accounting standard for AROs. The 2002 loss from a change in accounting principle resulted from adoption of a new accounting standard for goodwill and other intangible assets.

	As of December 31,				
	2006	2005	2004(2)	2003(3)	2002
	(in millions)				
BALANCE SHEET DATA					
Assets	$ 7,250	$ 7,023	$ 7,087	$ 12,299	$ 11,220
Current liabilities	646	846	994	1,203	1,356
Long-term obligations	3,035	3,330	3,530	2,919	3,022
Preferred securities	—	—	—	—	281
Shareholder's equity	2,582	1,910	1,745	1,954	1,751

(2) Assets decreased in 2004 compared to 2003 due to completion of the sale of substantially all EME's international assets.

(3) In the fourth quarter of 2003, EME adopted FIN No. 46, "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51," which required EME to reflect the junior subordinated deferrable debentures as a liability, which under the prior accounting treatment would have been eliminated in consolidation, instead of the Monthly Income Preferred Securities.

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

This MD&A contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. These statements reflect EME's current expectations and projections about future events based on EME's knowledge of present facts and circumstances and assumptions about future events and include any statement that does not directly relate to a historical or current fact. Other information distributed by EME that is incorporated in this MD&A, or that refers to or incorporates this MD&A, may also contain forward-looking statements. In this MD&A and elsewhere, the words "expects," "believes," "anticipates," "estimates," "projects," "intends," "plans," "probable," "may," "will," "could," "would," "should," and variations of such words and similar expressions, or discussions of strategy or plans, are intended to identify forward-looking statements. Such statements necessarily involve risks and uncertainties that could cause actual results to differ materially from those anticipated. See "Item 1. Business—Forward-Looking Statements" and "Item 1A. Risk Factors" for a discussion of some of the risks, uncertainties and other important factors that could cause results to differ, or otherwise could impact EME or its subsidiaries. Additional information about risks and uncertainties is contained throughout this MD&A. Readers are urged to read this entire annual report, including the information incorporated by reference, and carefully consider the risks, uncertainties and other factors that affect EME's business. Forward-looking statements speak only as of the date they are made and EME is not obligated to publicly update or revise forward-looking statements. Readers should review future reports filed by EME with the Securities and Exchange Commission.

This MD&A is presented in four sections:

MANAGEMENT'S OVERVIEW; CRITICAL ACCOUNTING ESTIMATES

Management's Overview

Introduction

EME is a holding company which operates primarily through its subsidiaries and affiliates which are engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from independent power production facilities. EME's subsidiaries or affiliates have typically been formed to own all or an interest in one or more power plants and ancillary facilities, with each plant or group of related plants being individually referred to by EME as a project. As of December 31, 2006, EME's subsidiaries and affiliates owned or leased interests in 29 operating power plants and 5 projects under construction.

EME's subsidiaries and affiliates have financed the development and construction or acquisition of its projects by capital contributions from EME and the incurrence of debt obligations by its subsidiaries and affiliates owning the operating facilities. These project level debt obligations are generally structured as non-recourse to EME, with several exceptions, including EME's guarantee of the Powerton and Joliet leases as part of a refinancing of indebtedness incurred by its project subsidiary to purchase the Illinois Plants. As a result, these project level debt obligations have structural priority with respect to revenues, cash flows and assets of the project companies over debt obligations incurred by EME itself. In this regard, EME has, itself, borrowed funds to make the equity contributions required of it for its projects and for general corporate purposes. Since EME does not, itself, directly own any revenue producing generation facilities, it depends for the most part on cash distributions from its projects to meet its debt service obligations, to pay for general and administrative expenses and to pay dividends to its parent, MEHC. Distributions to EME from projects are generally only available after all current debt service obligations at the project level have been paid and are further restricted by contractual restrictions on distributions included in the documentation evidencing the project level debt obligations.

Business Strategy

EME's business strategy includes the following core elements:

- Optimizing the value of its existing generation assets through:
  - operational excellence focused on long-term cost effective maintenance;
  - integration of commercial marketing and trading activities with plant operations to enhance gross margin; and
  - effective participation in regulatory rule-making in markets where EME operates.
- Diversifying the fuel type of its generation assets through:
  - developing and acquiring new renewable energy projects, primarily wind;
  - developing and acquiring natural gas-fired power projects in locations where existing or projected capacity for generation is constrained; and
  - developing new clean coal generation projects such as IGCC.
- Entering into more mid- to long-term power sales contracts in order to complement its merchant sales activities.
- Reducing cash flow volatility from merchant power plants through asset-based commodity hedging activities.
- Leveraging the knowledge and expertise in trading to enhance financial performance within a disciplined risk management structure.

Significant 2006 Items

Illinois Auction

In September 2006, the first Illinois power procurement auction was held by Commonwealth Edison according to the rules approved by the Illinois Commerce Commission. Through the auction, EMMT entered into two load requirements services contracts. Under the terms of these agreements, Midwest Generation expects to deliver, through EMMT, electricity, capacity and specified ancillary, transmission and load following services necessary to serve a portion of Commonwealth Edison's residential and small commercial customer load. The estimated megawatt-hours for 2007, 2008 and 2009 under these energy supply agreements are 8.5 million, 6.2 million and 1.8 million, respectively. The amount of power sold under these agreements can vary significantly with variations in load. See "Market Risk Exposures—Commodity Price Risk—Energy Price Risk Affecting Sales from the Illinois Plants" for further discussion of Midwest Generation's hedge position.

Environmental Developments Regarding Emissions

On December 11, 2006, Midwest Generation entered into an agreement with the Illinois EPA to reduce mercury, NO_x and SO_2 emissions at Midwest Generation's Illinois coal-fired power plants. Implementation of the agreement will require further regulatory proceedings in order to become effective, and once implemented the agreement will provide reasonable certainty of the timing and amount of emissions reductions which will be required of Midwest Generation's Illinois Plants for these pollutants through 2018. No assurance can be given that all required regulatory approvals will be received, and if not received, Midwest Generation will remain subject to existing and future requirements as to emissions of these pollutants. If the agreement is implemented as contemplated, Midwest Generation will be required to achieve specified emissions reductions through a combination of environmental retrofits or unit shutdowns. Capital expenditures are estimated (in 2006 dollars) between $2.7 billion and $3.4 billion. See "Liquidity and Capital Resources—Environmental Matters and Regulations—Air Quality Regulation—Clean Air Act—Illinois" for further discussion.

Business Development

EME has substantially expanded its activities with respect to the development of wind projects by entering into joint development agreements with third parties. During 2006, EME jointly completed development and commenced construction of four new wind projects (totaling 181 MW) with third parties. These projects, together with the Wildorado wind project (161 MW), which was a development project acquired in early 2006 with total construction costs, excluding capitalized interest, estimated to be $270 million, are expected to be completed during 2007. At December 31, 2006, joint development agreements were in place for multiple potential wind projects located in Pennsylvania, Illinois, Maine, Maryland, New York, West Virginia and Wisconsin, as well as a number of individual projects. To support completion of wind projects in 2007 and 2008, EME has purchased wind turbines supporting 487 MW of projects. Wind projects currently receive federal subsidies in the form of production tax credits. In December 2006, the production tax credit was extended to apply to new wind projects placed in service by December 31, 2008.

Financing Activities

On June 6, 2006, EME completed a private offering of $500 million of its 7.50% senior notes due 2013 and $500 million of its 7.75% senior notes due 2016. The proceeds of the offering were used, together with cash on hand, to purchase substantially all of EME's outstanding 10% senior notes due 2008 and 9.875% senior notes due 2011. On December 6, 2006, EME redeemed all of its remaining 10% senior notes and 9.875% senior notes outstanding. In connection with the purchase of these notes, EME recorded a $146 million loss on early extinguishment of debt in 2006.

On June 15, 2006, EME entered into a new credit agreement providing for $500 million in revolving loan and letter of credit capacity to be used for general corporate purposes including credit support for the hedging and trading activities of EME and its subsidiaries. The new credit agreement replaced EME's $98 million credit agreement.

ERP Initiative

EME has commenced a new initiative as part of an Edison International enterprise-wide project to implement an integrated enterprise resource planning (ERP) application from SAP during the next two years. The implementation of this application will replace EME's existing financial, human resources, materials management, and fuel management information systems with SAP's integrated ERP application.

The objective of this initiative is to improve the efficiency and effectiveness of EME's operational systems and enhance the transparency of information throughout the company.

Critical Accounting Estimates

Introduction

The accounting policies described below are viewed by management as "critical" because their correct application requires the use of material judgments and estimates, and they have a material impact on EME's results of operations and financial position.

Derivative Financial Instruments and Hedging Activities

EME uses derivative financial instruments for hedging activities and trading purposes. Derivative financial instruments are mainly utilized to manage exposure from changes in electricity and fuel prices and interest rates. EME follows SFAS No. 133, which requires derivative financial instruments to be recorded at their fair value unless an exception applies. SFAS No. 133 also requires that changes in a derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. For derivatives that qualify for hedge accounting, depending on the nature of the hedge, changes in fair value are either offset by changes in the fair value of the hedged assets, liabilities or firm commitments through earnings, or recognized in other comprehensive income until the hedged item is recognized in earnings. The ineffective portion of a derivative's change in fair value is immediately recognized in earnings. For further discussion, see "Market Risk Exposures—Accounting for Energy Contracts."

Management's judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal sales and purchases exception applies or whether individual transactions qualify for hedge accounting treatment. The majority of EME's long-term power sales and fuel supply agreements related to its generation activities either: (1) do not meet the definition of a derivative because they are not readily convertible to cash, or (2) qualify as normal purchases and sales and are, therefore, recorded on an accrual basis.

Derivative financial instruments used for trading purposes include forwards, futures, options, swaps and other financial instruments with third parties. EME records derivative financial instruments used for trading at fair value. The majority of EME's derivative financial instruments with a short-term duration (less than one year) are valued using quoted market prices. In the absence of quoted market prices, derivative financial instruments are valued considering the time value of money, volatility of the underlying commodity, and other factors as determined by EME. Resulting gains and losses are recognized in operating revenues in the accompanying consolidated income statements in the period of change. Derivative assets include open financial positions related to derivative financial instruments recorded at fair value, including cash flow hedges, that are "in-the-money" and the present value of net amounts receivable from structured transactions. Derivative liabilities include open financial positions related to derivative financial instruments, including cash flow hedges, that are "out-of-the-money."

Determining the fair value of derivatives under SFAS No. 133 is a critical accounting estimate because the fair value of a derivative is susceptible to significant change resulting from a number of factors, including: volatility of energy prices, credit risks, market liquidity and discount rates. See "Market Risk Exposures," for a description of risk management activities and sensitivities to change in market prices.

EME enters into master agreements and other arrangements in conducting hedging and trading activities with a right of setoff in the event of bankruptcy or default by the counterparty. These types of transactions are reported net in the balance sheet in accordance with FASB Interpretation No. 39, "Offsetting Amounts Related to Certain Contracts."

Impairment of Long-Lived Assets

EME follows SFAS No. 144. EME evaluates long-lived assets whenever indicators of impairment exist. This accounting standard requires that if the undiscounted expected future cash flow from a company's assets or group of assets (without interest charges) is less than its carrying value, asset impairment must be recognized in the financial statements. The amount of impairment is determined by the difference between the carrying amount and fair value of the asset.

The assessment of impairment is a critical accounting estimate because significant management judgment is required to determine: (1) if an indicator of impairment has occurred, (2) how assets should be grouped, (3) the forecast of undiscounted expected future cash flow over the asset's estimated useful life to determine if an impairment exists, and (4) if an impairment exists, the fair value of the asset or asset group. Factors that EME considers important, which could trigger an impairment, include operating losses from a project, projected future operating losses, the financial condition of counterparties, or significant negative industry or economic trends. During 2005 and 2004, EME recorded impairment charges of $55 million and $35 million, respectively, related to specific assets included in continuing operations. See "Results of Operations—Results of Continuing Operations—Earnings from Consolidated Operations—Illinois Plants" and "—Earnings from Unconsolidated Affiliates—Impairment Loss on Equity Method Investment."

Off-Balance Sheet Financing

EME has entered into sale-leaseback transactions related to the Powerton and Joliet plants in Illinois and the Homer City facilities in Pennsylvania. See "Liquidity and Capital Resources—Contractual Obligations, Commitments and Contingencies—Operating Lease Obligations." Each of these transactions was completed and accounted for by EME as an operating lease in its consolidated financial statements in accordance with SFAS No. 98, which requires, among other things, that all the risk and rewards of ownership of assets be transferred to a new owner without continuing involvement in the assets by the former owner other than as normal for a lessee. The sale-leaseback transactions of these power plants were complex matters that involved management judgment to determine compliance with SFAS No. 98, including the transfer of all the risk and rewards of ownership of the power plants to the new owner without EME's continuing involvement other than as normal for a lessee. These transactions were entered into to provide a source of capital either to fund the original acquisition of the assets or to repay indebtedness previously incurred for the acquisition. Each of these leases uses special purpose entities.

Based on existing accounting guidance, EME does not record these lease obligations in its consolidated balance sheet. If these transactions were required to be consolidated as a result of future changes in accounting guidance, it would: (1) increase property, plant and equipment and long-term obligations in the consolidated financial position, and (2) impact the pattern of expense recognition related to these obligations because EME would likely change from its current straight-line recognition of rental expense to an annual recognition of the straight-line depreciation on the leased assets as well as the interest component of the financings which is weighted more heavily toward the early years of the obligations. The difference in expense recognition would not affect EME's cash flows under these transactions. See "Liquidity and Capital Resources—Off-Balance Sheet Transactions—Sale-Leaseback Transactions."

Contract Indemnities

During 2004, EME sold a majority of its international operations. The asset sale agreements contain indemnities from EME to the purchasers, including indemnification for pre-closing environmental liabilities and for pre-closing foreign taxes imposed with respect to operations of the assets prior to the sale. At December 31, 2006, EME had recorded an estimated liability of $95 million related to these matters.

In addition, Midwest Generation has agreed to reimburse Commonwealth Edison and Exelon Generation for 50% of specific asbestos claims pending as of February 2003 and related expenses less recovery of insurance costs, and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in a supplemental agreement. See "Liquidity and Capital Resources—Contractual Obligations, Commitments and Contingencies—Commercial Commitments." Midwest Generation engaged an independent actuary during 2004 with extensive experience in performing asbestos studies to estimate future losses based on its claims experience and other available information. In calculating future losses, the actuary made various assumptions, including, but not limited to, the settlement of future claims under the supplemental agreement with Commonwealth Edison as described above, the distribution of exposure sites, and that the filing date of asbestos claims will not be after 2045. At December 31, 2006, Midwest Generation had recorded a liability of $65 million related to this contract indemnity.

Income Taxes

SFAS No. 109, "Accounting for Income Taxes," requires the asset and liability approach for financial accounting and reporting for deferred income taxes. EME uses the asset and liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. See "Edison Mission Energy and Subsidiaries Notes to Consolidated Financial Statements—Note 10. Income Taxes" for additional details.

As part of the process of preparing its consolidated financial statements, EME is required to estimate its income taxes in each jurisdiction in which it operates. This process involves estimating actual current tax expense together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within EME's consolidated balance sheet. In addition, estimated taxes for uncertain tax positions are accrued and included in other long-term liabilities in the consolidated balance sheet.

For additional information regarding EME's accounting policies, see "Edison Mission Energy and Subsidiaries Notes to Consolidated Financial Statements—Note 1. Summary of Significant Accounting Policies."

RESULTS OF OPERATIONS

Introduction

This section discusses operating results in 2006, 2005 and 2004. Continuing operations include EME's Illinois Plants and Homer City facilities, energy trading, power projects under contract, corporate interest expense and general and administrative expenses. Discontinued operations include all of EME's international operations, except the Doga project. This section also discusses the effect of new accounting pronouncements on EME's consolidated financial statements.

On April 1, 2006, EME received, as a capital contribution, ownership interests in a portfolio of wind projects located in Iowa and Minnesota and a small biomass project. These projects were previously owned by EME's affiliate, Edison Capital. Both MEHC and Edison Capital are wholly owned subsidiaries of Edison Mission Group, which is a subsidiary of Edison International. EME accounted for this acquisition at Edison Capital's historical cost as a transaction between entities under common control. Therefore, these consolidated financial statements include the results of operations, financial position and cash flows of the acquired projects as though EME had such ownership throughout the periods presented.

This section is organized under the following headings:

Net Income Summary

Net income is comprised of the following components:

	Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Income (loss) from continuing operations	$ 316	$ 414	$ (560)
Income from discontinued operations	98	29	690
Cumulative changes in accounting principle	—	(1)	—
Net Income	$ 414	$ 442	$ 130

EME's 2006 decrease in income from continuing operations was primarily due to loss on early extinguishment of debt, lower generation at the Illinois Plants and lower energy trading income from EMMT. Partially offsetting these decreases were a favorable change in SFAS No. 133 unrealized gains, lower net interest expense and the March Point impairment loss recorded during 2005.

EME's 2005 increase in income from continuing operations was primarily attributable to the absence in 2005 as compared to 2004 of a $608 million, after tax, charge related to the termination of the Collins Station lease and the return of ownership of the Collins Station to EME, and the impairment of plant assets and related inventory reserves. The 2005 increase was also due to higher energy trading income in 2005 and higher wholesale energy prices at the Illinois Plants in 2005. Further details regarding income from continuing operations is set forth below.

EME's 2006 and 2005 income from discontinued operations, net of tax, was primarily related to distributions authorized by the liquidators of the Lakeland power project. EME has received a total of $125 million and $24 million of distributions in 2006 and 2005, respectively, from the settlement of a 2001 claim for termination of a power contract by a subsidiary of TXU Europe Group plc. The activities of the Lakeland liquidator are near completion and substantially all the distributions from the Lakeland project have been made.

EME's 2005 loss from a change in accounting principle resulted from the adoption of a new accounting standard for conditional AROs. See "Results of Continuing Operations—Cumulative Effect of Change in Accounting Principle" for further discussion of this change in accounting.

Results of Continuing Operations

Overview

EME operates in one line of business, independent power production. Operating revenues are primarily derived from the sale of power generated from the Illinois Plants and the Homer City facilities. Intercompany interest expense and income between EME and its consolidated subsidiaries have been eliminated in the following project results, except as described below with respect to loans provided to EME from a wholly owned subsidiary, Midwest Generation, and loans from Midwest Generation to EMMT for margining. Equity in income from unconsolidated affiliates relates to energy projects accounted for under the equity method. EME recognizes its proportional share of the income or loss of such entities.

EME uses the words "earnings" or "losses" in this section to describe income or loss from continuing operations before income taxes.

The following section provides a summary of the operating results for the three years ended December 31, 2006 together with discussions of the contributions by specific projects and of other significant factors affecting these results.

	Years Ended December 31		
	2006	2005	2004
		(in millions)	
Project Earnings (Losses)(1)			
Consolidated operations			
Illinois Plants	$ 459	$ 547	$ (881)
Homer City	156	74	77
Energy Trading(2)	130	195	23
Doga(3)	—	—	6
San Juan Mesa	7	—	—
Gain on sale of assets	4	—	—
Storm Lake	5	2	8
Other	—	(1)	4
Unconsolidated affiliates			
Big 4 projects	132	158	142
Sunrise	34	29	28
March Point	—	9	17
Impairment loss on equity method investment	—	(55)	—
Doga	1	7	1
Other	12	13	12
	940	978	(563)
Corporate interest income	82	55	6
Corporate interest expense	(253)	(270)	(283)
Corporate administrative and general	(113)	(126)	(150)
Gain on sale of investments	—	—	43
Loss on early extinguishment of debt	(146)	(4)	—
Other income (expense), net	10	(3)	(11)
	$ 520	$ 630	$ (958)

(1) Project earnings are equal to income from continuing operations before income taxes, except for production tax credits. Accordingly, project earnings for the wind projects include $16 million, $8 million and $7 million of production tax credits for the years ended December 31, 2006, 2005 and 2004, respectively. Production tax credits are recognized as wind energy is generated based upon a per kilowatt-hour rate prescribed in applicable federal and state statutes. Under GAAP, production tax credits generated by the wind projects are recorded as a reduction in income taxes. Accordingly, project earnings (losses) represent a non-GAAP performance measure which may not be comparable to those of other companies. Management believes that inclusion of production tax credits in project earnings for wind projects is more meaningful for investors as federal and state subsidies are an integral part of the economics of these projects. The following table reconciles the total project earnings as shown above with income from continuing operations before income taxes and minority interest under GAAP:

	Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Project earnings (losses)	$ 520	$ 630	$ (958)
Less: Production tax credits	(16)	(8)	(7)
Income (loss) from continuing operations before income taxes and minority interest	$ 504	$ 622	$ (965)

(2) Income from energy trading represents the gains recognized from price changes associated with the purchase and sale of contracts for electricity, fuels and transmission. The overhead cost of energy trading is included in administrative and general expenses.

(3) Income before taxes of Doga represents both EME's 80% ownership interest and the ownership interests of minority interest holders on a calendar year basis. The interests of minority shareholders in the after-tax earnings of Doga are reflected in a separate line item in the consolidated statements of income.

Earnings from Consolidated Operations

Illinois Plants

	Years Ended December 31		
	2006	**2005**	**2004**
		(in millions)	
Operating Revenues	$ 1,399	$ 1,429	$ 1,058
Operating Expenses			
Fuel(1)	382	383	408
Gain on sale of emission allowances(2)	(16)	(56)	(26)
Plant operations	369	351	379
Plant operating leases	75	75	84
Depreciation and amortization	101	99	116
Loss on lease termination, asset impairment and other charges	4	7	989
Administrative and general	19	19	1
Total operating expenses	934	878	1,951
Operating Income (Loss)	465	551	(893)
Other Income (Expense)			
Interest income from note receivable from EME	115	113	113
Interest expense and other	(121)	(117)	(101)
Total other income (expense)	(6)	(4)	12
Income (Loss) Before Taxes	$ 459	$ 547	$ (881)
Statistics			
Generation (in GWh):			
Merchant	28,898	30,953	17,133
Power purchase agreement	—	—	13,435
Total coal-fired generation	28,898	30,953	30,568
Equivalent availability(3)	79.3%	79.6%	84.4%
Capacity factor(4)	58.8%	63.0%	65.3%
Load factor(5)	74.1%	79.1%	77.4%
Forced outage rate(6)	7.9%	7.8%	5.4%
Average realized energy price/MWh(7):			
Merchant	$ 46.19	$ 45.55	$ 31.20
Power purchase agreement	$ —	$ —	$ 17.60
Total coal-fired generation(8)	$ 46.19	$ 45.55	$ 25.22
Capacity revenue only (in millions)	$ 24	$ 27	$ 289
Average fuel costs/MWh	$ 13.19	$ 12.40	$ 11.60

(1) The Illinois Plants purchased NO_x emission allowances from the Homer City facilities at fair market value. Purchases were $6 million in 2006, $5 million in 2005 and none in 2004. These purchases are included in fuel costs.

(2) The Illinois Plants sold excess SO_2 emission allowances to the Homer City facilities at fair market value. Sales to the Homer City facilities were $14 million in 2006, $61 million in 2005 and $26 million in 2004. These sales reduced operating expenses. EME recorded $6 million of intercompany profit during the first quarter of 2006 that was eliminated by EME in 2005 on emission allowances sold by the Illinois Plants to the Homer City facilities in the fourth quarter of 2005 but not used by the Homer City facilities until the first quarter of 2006. In addition, EME eliminated $4 million of intercompany profit during the fourth quarter of 2006 on emission allowances sold but not yet used by the Homer City facilities at December 31, 2006.

(3) The equivalent availability factor is defined as the number of megawatt-hours the coal plants are available to generate electricity divided by the product of the capacity of the coal plants (in MW) and the number of hours in the period. Equivalent availability reflects the impact of the unit's inability to achieve full load, referred to as derating, as well as outages which result in a complete unit shutdown. The coal plants are not available during periods of planned and unplanned maintenance.

(4) The capacity factor is defined as the actual number of megawatt-hours generated by the coal plants divided by the product of the capacity of the coal plants (in MW) and the number of hours in the period.

(5) The load factor is determined by dividing capacity factor by the equivalent availability factor.

(6) Midwest Generation refers to unplanned maintenance as a forced outage.

(7) The average realized energy price reflects the average price at which energy is sold into the market including the effects of hedges, real-time and day-ahead sales and PJM fees and ancillary services. It is determined by dividing (i) operating revenue less unrealized SFAS No. 133 gains (losses) and other non-energy related revenue by (ii) total generation. Revenue related to capacity sales are excluded from the calculation of average realized energy price.

(8) The average realized energy price in 2004 represented an average, weighted by generation, of energy prices earned by the merchant coal plants and energy prices earned under the power purchase agreements with Exelon Generation. Due to the structure of the power purchase agreements with Exelon Generation (with higher capacity prices and lower energy prices), the composite data in 2004 is not directly comparable to 2005 and 2006 merchant energy prices.

Earnings from the Illinois Plants decreased $88 million in 2006 compared to 2005, and increased $1.4 billion in 2005 compared to 2004. The 2006 decrease in earnings was primarily attributable to lower energy revenues resulting from lower generation, a decrease in sales of excess SO_2 emission allowances in 2006, as compared to 2005, due to lower prices for SO_2 allowances and higher plant overhaul costs. Partially offsetting these decreases was an increase in unrealized gains in 2006 related to hedge contracts described below.

Earnings from the Illinois Plants, excluding discrete items discussed below, increased $438 million in 2005 compared to 2004. The 2005 increase in earnings is due to the following factors:

- substantially higher energy revenues resulting from increased average realized energy prices;
- higher fuel costs in 2004 during the period the Collins Station operated (operations ceased effective September 30, 2004);
- an increase in sales of excess SO_2 emission allowances in 2005, as compared to 2004, due to higher market prices;
- the absence in 2005 as compared to 2004 of a $56 million charge recorded during the fourth quarter of 2004 related to an estimate of possible future payments under a contract indemnity agreement related to asbestos claims with respect to activities at the Illinois Plants prior to their acquisition in 1999. See "Liquidity and Capital Resources—Contractual Obligations, Commitments and Contingencies—Indemnities Provided as Part of the Acquisition of the Illinois Plants"; and
- lower plant operating lease costs due to the termination of the Collins Station lease in April 2004.

Partially offset by:

- lower capacity revenues resulting from the expiration of the power purchase agreements with Exelon Generation;
- higher plant operation costs due to higher planned maintenance;
- higher coal costs attributable to higher coal prices primarily due to price escalation under coal and transportation agreements; and
- higher interest expense primarily attributable to a full year of interest expense in 2005 versus approximately eight months of interest expense in 2004 related to debt issued in April 2004 by Midwest Generation, which owns or leases the Illinois Plants.

Discrete items affecting the loss of the Illinois Plants in 2004 include:

- $961 million loss in 2004 related to the termination of the Collins Station lease and the return of ownership of the Collins Station to EME, and the impairment of plant assets and related inventory reserves. Management concluded that the Collins Station was not economically competitive in the marketplace given generation overcapacity and ceased operations effective September 30, 2004; and
- $29 million loss recorded in 2004 related to the impairment of small peaking units in Illinois.

Included in operating revenues were unrealized gains (losses) of $30 million, $(19) million and $(4) million in 2006, 2005 and 2004, respectively. Unrealized gains (losses) are primarily due to power contracts that did not qualify for hedge accounting under SFAS No. 133 (sometimes referred to as economic hedges). These energy contracts were entered into to hedge the price risk related to projected sales of power. During 2005 and 2004, power prices increased, resulting in mark-to-market losses on economic hedges. As economic hedge contracts were settled in 2006 the previous unrealized losses resulted in unrealized gains. The 2006 unrealized gains also included $8 million of mark-to-market gains from economic hedges for periods subsequent to December 31, 2006, resulting from a decline in market prices during the fourth quarter of 2006. See "Market Risk Exposures—Commodity Price Risk" for more information regarding forward market prices.

The earnings (losses) of the Illinois Plants included interest income of $115 million for the year ended December 31, 2006 and $113 million for each of the years ended December 31, 2005 and 2004 related to loans to EME. In August 2000, Midwest Generation, which owns or leases the Illinois Plants, entered into a sale-leaseback transaction of the Powerton-Joliet facilities. The proceeds from the sale of these facilities were loaned to EME, which also provided a guarantee of the related lease obligations of Midwest Generation. The Powerton-Joliet sale-leaseback is recorded as an operating lease for accounting purposes. See "Management's Overview; Critical Accounting Estimates—Critical Accounting Estimates—Off-Balance Sheet Financing" for further discussion of these leases.

Homer City

	Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Operating Revenues	$ 642	$ 592	$ 497
Operating Expenses			
Fuel(1)	283	288	215
Gain on sale of emission allowances(2)	(7)	(4)	—
Plant operations	106	112	88
Plant operating leases	102	102	102
Depreciation and amortization	16	16	15
Administrative and general	5	6	3
Total operating expenses	505	520	423
Operating Income	137	72	74
Other Income (Expense)			
Interest and other income	20	3	4
Interest expense	(1)	(1)	(1)
Total other income	19	2	3
Income Before Taxes	$ 156	$ 74	$ 77
Statistics			
Generation (in GWh)	12,286	13,637	13,292
Equivalent availability(3)	81.9%	85.2%	85.1%
Capacity factor(4)	74.3%	82.4%	80.1%
Load factor(5)	90.7%	96.7%	94.1%
Forced outage rate(6)	13.5%	4.8%	5.3%
Average realized energy price/MWh(7)	$ 48.02	$ 45.05	$ 35.93
Capacity revenue only (in millions)	$ 16	$ 18	$ 28
Average fuel costs/MWh	$ 23.05	$ 21.08	$ 16.15

(1) The Homer City facilities purchased SO_2 emission allowances from the Illinois Plants at fair market value. Purchases were $14 million in 2006, $61 million in 2005 and $26 million in 2004. These purchases are included in fuel costs.

(2) The Homer City facilities sold excess NO_x emission allowances to the Illinois Plants at fair market value. Sales to the Illinois Plants were $6 million in 2006, $5 million in 2005 and none in 2004. These sales reduced operating expenses. In addition, EME recorded a $1 million intercompany profit during 2006, eliminated in 2005, on emission allowances sold by the Homer City facilities to the Illinois Plants but not used by the Illinois Plants until 2006.

(3) The equivalent availability factor is defined as the number of megawatt-hours the coal plants are available to generate electricity divided by the product of the capacity of the coal plants (in MW) and the number of hours in the period. Equivalent availability reflects the impact of the unit's inability to achieve full load, referred to as derating, as well as outages which result in a complete unit shutdown. The coal plants are not available during periods of planned and unplanned maintenance.

(4) The capacity factor is defined as the actual number of megawatt-hours generated by the coal plants divided by the product of the capacity of the coal plants (in MW) and the number of hours in the period.

(5) The load factor is determined by dividing capacity factor by the equivalent availability factor.

(6) Homer City refers to unplanned maintenance as a forced outage.

(7) The average realized energy price reflects the average price at which energy is sold into the market including the effects of hedges, real-time and day-ahead sales and PJM fees and ancillary services. It is determined by dividing (i) operating revenue less unrealized SFAS No. 133 gains (losses) and other non-energy related revenue by (ii) total generation.

Earnings from Homer City increased $82 million in 2006 compared to 2005 and decreased $3 million in 2005 compared to 2004. The 2006 increase was primarily attributable to the timing of unrealized gains and losses related to hedge contracts discussed below, higher average realized energy prices and lower prices of SO_2 emission allowances. Partially offsetting these increases were lower generation in 2006 due to an unplanned outage at Unit 3 (net of estimated insurance recoveries) and higher coal prices. Homer City is generally classified as a baseload plant, which means the amount of generation is largely based on the availability of the plant. Accordingly, the Unit 3 outage reduced the amount of generation during 2006. Included in fuel costs were $35 million, $81 million and $42 million in 2006, 2005 and 2004, respectively, related to the net cost of SO_2 emission allowances. See "Market Risk Exposures—Commodity Price Risk—Emission Allowances Price Risk" for more information regarding the price of SO_2 allowances.

The 2005 decrease was primarily attributable to unrealized losses related to hedge contracts, mostly offset by higher energy margin including the effect of higher wholesale energy prices, higher coal prices, higher priced SO_2 emission allowances and higher plant operations costs. Homer City had higher planned equipment maintenance costs in 2005 compared to 2004 and incurred costs in 2005 related to the replacement of the catalyst for the pollution control equipment.

Included in operating revenues were unrealized gains (losses) from hedge activities of $35 million, $(41) million and $(13) million in 2006, 2005 and 2004, respectively. Unrealized gains (losses) were primarily attributable to the ineffective portion of forward and futures contracts which are derivatives that qualify as cash flow hedges under SFAS No. 133. The ineffective portion of hedge contracts at Homer City was primarily attributable to changes in the difference between energy prices at PJM West Hub (the settlement point under forward contracts) and the energy prices at the Homer City busbar (the delivery point where power generated by the Homer City facilities is delivered into the transmission system). At December 31, 2006, unrealized losses of $11 million were recognized from the ineffective portion of cash flow hedges related to 2007. See "Market Risk Exposures—Commodity Price Risk" for more information regarding forward market prices.

The average realized energy price received by Homer City in 2006, 2005 and 2004 was $48.02/MWh, $45.05/MWh and $35.93/MWh, respectively, compared to the average real-time market price at the Homer City busbar for the same periods of $45.15/MWh, $54.80/MWh and $40.79/MWh, respectively. Homer City's average realized energy price varies from the average real-time market price due to: (1) hedge contracts having been entered into in prior periods, and (2) changes in the differential in market prices at the PJM West Hub versus the Homer City busbar. The increase in the differential is referred to as a widening of the basis between these PJM locations. Homer City hedges its energy price risk at PJM West Hub and retains the risk that the basis between PJM West Hub and Homer City widens. During 2005, the basis between these two locations widened substantially resulting in ineffective losses on hedge contracts. See "Market Risk Exposures—Commodity Price Risk—Basis Risk."

Homer City Unit 3 Outage—

On January 29, 2006, the main power transformer on Unit 3 of the Homer City facilities failed resulting in a suspension of operations at this unit. Homer City secured a replacement transformer and Unit 3 returned to service on May 5, 2006. Homer City has adjusted its previously planned outage schedules for Unit 3 and the other Homer City units in order to minimize to the extent practicable overall outage activities for all units through the first half of 2007. The main transformer failure resulted in claims under Homer City's property and business interruption insurance policies. At December 31, 2006, Homer City had a $17 million receivable related to these claims. Resolution of the claims is subject to a number of uncertainties, including computations of the lost profit during the outage period.

Seasonal Disclosure

Due to higher electric demand resulting from warmer weather during the summer months and cold weather during the winter months, electric revenues from the Illinois Plants and the Homer City facilities vary substantially on a seasonal basis. In addition, maintenance outages generally are scheduled during periods of lower projected electric demand (spring and fall) further reducing generation and increasing major maintenance costs which are recorded as an expense when incurred. Accordingly, earnings from the Illinois Plants and the Homer City facilities are seasonal and have significant variability from quarter to quarter. Seasonal fluctuations may also be affected by changes in market prices. See "Market Risk Exposures—Commodity Price Risk-Energy Price Risk Affecting Sales from the Illinois Plants" and "—Energy Price Risk Affecting Sales from the Homer City Facilities" for further discussion regarding market prices.

Energy Trading

EME seeks to generate profit by utilizing its subsidiary, EMMT, to engage in trading activities in those markets in which it is active as a result of its management of the merchant power plants of Midwest Generation and Homer City. EMMT trades power, fuel and transmission congestion primarily in the eastern power grid using products available over the counter, through exchanges and from ISOs. Earnings from energy trading activities were $130 million, $195 million and $23 million in 2006, 2005 and 2004, respectively. The 2006 decrease in earnings from energy trading activities was primarily attributable to less congestion due in part to lower wholesale energy prices driven by lower natural gas prices. Volatile market conditions in 2005, driven by increased natural gas and oil prices and warmer summer temperatures, created favorable conditions for EMMT's trading strategies in 2005 compared to 2004.

San Juan Mesa

EME's earnings from the San Juan Mesa wind project were $7 million in 2006, with no earnings recorded in 2005 and 2004 due to the acquisition of the San Juan Mesa wind project on December 27, 2005.

During the first quarter of 2006, EME completed the sale of 25% of its ownership interest in the San Juan Mesa wind project to Citi Renewable Investments I LLC, a wholly owned subsidiary of Citicorp North America, Inc. Proceeds from the sale were $43 million. EME recorded a pre-tax gain on the sale of approximately $4 million during the first quarter of 2006.

Earnings from Unconsolidated Affiliates

Big 4 Projects

EME owns partnership investments (50% ownership or less) in Kern River Cogeneration Company, Midway-Sunset Cogeneration Company, Sycamore Cogeneration Company and Watson Cogeneration Company. These projects have similar economic characteristics and have been used, collectively, to secure financing by Edison Mission Energy Funding Corp., a special purpose entity. Due to similar economic characteristics and the financing related to EME's equity investments in these projects, EME evaluates them collectively and refers to them as the Big 4 projects.

Earnings from the Big 4 projects decreased $26 million in 2006 compared to 2005, and increased $16 million in 2005 compared to 2004. The 2006 change in earnings was primarily due to lower earnings from the Kern River project during 2006, compared to 2005, resulting from the expiration of the project's long-term power purchase and steam supply agreements in August 2005. Effective June 1, 2006, the project commenced selling electricity under a five-year bilateral agreement with SCE. The decrease in earnings was also attributable to lower earnings from the Watson and Sycamore projects during 2006, compared to 2005, primarily due to lower energy margins resulting from lower natural gas prices.

The 2005 change in earnings was largely due to higher energy prices in 2005. The impact of the higher energy prices in 2005 was partially offset by lower earnings from the Kern River project during 2005, compared to 2004, resulting from the expiration of the project's long-term power purchase and steam supply agreements described above and an unplanned outage in December 2005.

Earnings from the Big 4 projects are net of interest expense of $5 million, $9 million and $12 million in 2006, 2005 and 2004, respectively, with respect to Edison Mission Energy Funding.

Sunrise

Earnings from the Sunrise project increased $5 million in 2006 from 2005 and $1 million in 2005 from 2004. The 2006 increase was largely due to higher capacity revenues and availability incentive payments in 2006.

March Point

Earnings from March Point decreased $8 million in 2005 from 2004. The 2005 decrease is primarily attributable to earnings recorded for a full year in 2004, compared to nine months in 2005 due to the impairment charge recorded during the third quarter of 2005 discussed below.

Impairment Loss on Equity Method Investment

During the third quarter of 2005, EME fully impaired its equity investment in the March Point project following an updated forecast of future project cash flows. The March Point project is a 140 MW natural gas-fired cogeneration facility located in Anacortes, Washington, in which a subsidiary of EME owns a 50% partnership interest. The March Point project sells electricity to Puget Sound Energy, Inc. under two power purchase agreements that expire in 2011 and sells steam to Equilon Enterprises, LLC (a subsidiary of Shell Oil) under a steam supply agreement that also expires in 2011. March Point purchases a portion of its fuel requirements under long-term contracts with the remaining requirements purchased at current market prices. March Point's power sales agreements do not provide for a price adjustment related to the project's fuel costs. During the first nine months of 2005, long-term natural gas prices increased substantially, thereby adversely affecting the future cash flows of the March Point project. As a result, management concluded that its investment was impaired and recorded a $55 million charge during the third quarter of 2005.

Doga

In accordance with FIN 46(R), EME determined that it was not the primary beneficiary of the Doga project and, accordingly, deconsolidated this project at March 31, 2004. Beginning April 1, 2004, EME recorded its interest in the Doga project on the equity method basis of accounting. Earnings from the Doga project were $1 million in 2006, $7 million in 2005 and $1 million in 2004, representing earnings from the final three quarters of 2004.

Earnings from the Doga project decreased $6 million in 2006, compared to the corresponding period of 2005. The decrease in earnings was primarily due to a change in the Turkish corporate tax rate. In June 2006, the corporate tax rate in Turkey was reduced from 30% to 20%. Although the decrease in the corporate tax rate will reduce future income tax payments, Doga reported a loss from a reduction in deferred tax assets (related to levelization of income under the power purchase agreement for financial reporting purposes).

Seasonal Disclosure

EME's third quarter equity in income from its energy projects is materially higher than equity in income related to other quarters of the year due to warmer weather during the summer months and because a number of EME's energy projects located on the West Coast have power sales contracts that provide for higher payments during the summer months.

Corporate Interest Income

EME corporate interest income increased $27 million in 2006 from 2005 and $49 million in 2005 from 2004. The 2006 increase was primarily attributable to higher interest rates in 2006 compared to 2005. The 2005 increase was primarily attributable to higher average cash balances in 2005 compared to 2004 due largely to cash proceeds received from the sale of international operations.

Corporate Interest Expense

	Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Interest expense to third parties	$ 138	$ 157	$ 170
Interest expense to Midwest Generation(1)	115	113	113
Total corporate interest expense	$ 253	$ 270	$ 283

(1) Includes interest expense of EMMT related to loans from Midwest Generation for margining.

Interest Expense to Third Parties

EME's interest expense to third parties decreased $19 million in 2006, compared to the corresponding period of 2005. The decrease was primarily attributable to lower interest rates resulting from EME's refinancing in June 2006.

Corporate Administrative and General Expenses

Administrative and general expenses decreased $13 million in 2006 from 2005, and $24 million in 2005 from 2004. The 2006 decrease was primarily due to $13 million of costs incurred during 2005 for severance and related costs in connection with EME restructuring activities. The 2005 decrease was primarily due to decreased use of third-party consultants partially offset by charges for severance and related costs recorded in 2005.

Gain on Sale of Investments

On January 4, 2004, EME completed the sale of its ownership interest in Four Star Oil & Gas Company and recorded a pre-tax gain of $47 million. Proceeds from the sale were approximately $100 million.

On March 31, 2004, EME completed the sale of 100% of its stock of Mission Energy New York, Inc., which in turn owned a 50% partnership interest in Brooklyn Navy Yard, to a third party for a sales price of approximately $42 million. EME recorded an impairment charge of $53 million during the fourth quarter of 2003 related to the planned disposition of this investment and a pre-tax loss of approximately $4 million during the first quarter of 2004 due to changes in the terms of the sale.

Loss on Early Extinguishment of Debt

Loss on early extinguishment of debt was $146 million in 2006 related to the early repayment of all EME's 10% senior notes due August 15, 2008 and 9.875% senior notes due April 15, 2011.

Loss on early extinguishment of debt was $4 million in 2005. Extinguishment of debt consisted of a $4 million loss related to the early repayment of EME's junior subordinated debentures recorded during the first quarter of 2005.

Other Income (Expense), Net

Other income (expense), net increased $13 million in 2006 from 2005 and $8 million in 2005 from 2004. The 2006 increase was partially attributable to an $8 million gain related to receipt of shares from Mirant Corporation from settlement of a claim recorded during the first quarter of 2006.

Income Taxes

EME's income tax provision (benefit) from continuing operations was $189 million in 2006, $208 million in 2005 and $(406) million in 2004. Income tax benefits are recognized pursuant to a tax-allocation agreement with Edison International. See "Liquidity and Capital Resources—EME's Liquidity as a Holding Company—Intercompany Tax-Allocation Agreement." EME recognized $16 million, $8 million and $7 million of production tax credits related to wind projects for the years ended December 31, 2006, 2005 and 2004, respectively, and $14 million, $8 million and $8 million for each period related to estimated state income tax benefits allocated from Edison International. During the second quarter of 2005, EME resolved a dispute regarding additional taxes asserted by the Internal Revenue Service during the audit of the 1994-1996 tax returns. As a result of the resolution of this item, EME reversed $11.5 million of accrued taxes, recording this amount as a reduction of income taxes during the second quarter of 2005. During the second quarter of 2004, EME recorded a tax benefit of $368 million primarily relating to the loss on the termination of the Collins Station lease, and during the first quarter of 2004, EME recorded a tax provision of $18 million relating to the sale of 100% of its stock in Edison Mission Energy Oil & Gas, which in turn held interests in Four Star Oil & Gas.

Cumulative Effect of Change in Accounting Principle

Statement of Financial Accounting Standard Interpretation No. 47

Effective December 31, 2005, EME adopted Financial Accounting Standard Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47). For further discussion of FIN 47 refer to "New Accounting Pronouncements." EME recorded a $1 million, after tax, decrease to net income as the cumulative effect of the adoption of FIN 47.

Results of Discontinued Operations

Income from discontinued operations, net of tax, was $98 million in 2006, $29 million in 2005 and $690 million in 2004. The 2006 increase is largely attributable to distributions received from the Lakeland project, discussed below. In addition, EME recorded a tax benefit adjustment of $22 million during the fourth quarter of 2006, which resulted from resolution of a tax uncertainty pertaining to the ownership interest in a foreign project. During 2005, EME completed the following sales:

- On January 10, 2005, EME sold its 50% equity interest in the Caliraya-Botocan-Kalayaan (CBK) hydroelectric power project to CBK Projects B.V. Proceeds from the sale were approximately $104 million.
- On February 3, 2005, EME sold its 25% equity interest in the Tri Energy project to IPM. Proceeds from the sale were approximately $20 million.

The aggregate after-tax gain on sale of the projects mentioned above was $5 million.

During the fourth quarter of 2005, EME recorded an after-tax charge of $25 million related to a tax indemnity for a project sold to IPM in December 2004. This charge related to an adverse tax court ruling in Spain, which the local company appealed. During the third quarter of 2005, EME recorded tax benefit adjustments of $28 million, which resulted from completion of the 2004 federal and California income tax returns and quarterly review of tax accruals. Most of the tax adjustments are related to the sale of the international projects in December 2004.

During 2004, EME completed the following sales:

- On September 30, 2004, EME sold its 51.2% interest in Contact Energy to Origin Energy New Zealand Limited. Consideration for the sale was NZ$1,101.4 million (approximately US$739 million) in cash and NZ$535 million (approximately US$359 million) of debt assumed by the purchaser.
- On December 16, 2004, EME sold the stock and related assets of MEC International B.V. (MECIBV) to IPM. The sale of MECIBV included the sale of EME's interests in ten electric power generating projects or companies located in Europe, Asia, Australia, and Puerto Rico. Consideration from the sale of MECIBV was $2.0 billion in cash. EME retained its ownership of the subsidiaries associated with the Lakeland project and some inactive subsidiaries.

The aggregate after-tax gain on the sale of the above-referenced international projects was $533 million.

Lakeland Project

EME previously owned a 220 MW power plant located in the United Kingdom, referred to as the Lakeland project. An administrative receiver was appointed in 2002 as a result of a default by the project's counterparty, a subsidiary of TXU Europe Group plc. Following a claim for termination of the power sales agreement, the Lakeland project received a settlement of £116 million (approximately $217 million). EME is entitled to receive the remaining amount of the settlement after payment of creditor claims. As creditor claims have been settled, EME has received to date payments of £13 million (approximately $24 million) in 2005, £72 million (approximately $125 million) in 2006 and £4 million (approximately $8 million) in January 2007. The after-tax income attributable to the Lakeland project was $85 million and $24 million for 2006 and 2005, respectively, and none in 2004. Beginning in 2002, EME reported the Lakeland project as discontinued operations and accounts for its ownership of Lakeland Power on the cost method (earnings are recognized as cash is distributed from the project).

Related Party Transactions

Specified EME subsidiaries have ownership in partnerships that sell electricity generated by their project facilities to SCE and others under the terms of long-term power purchase agreements. Sales by these partnerships to SCE under these agreements amounted to $756 million, $932 million and $824 million in 2006, 2005 and 2004, respectively.

New Accounting Pronouncements

Accounting Principles Adopted

Statement of Financial Accounting Standards No. 123(R)

SFAS No. 123(R) requires companies to use the fair value accounting method for stock-based compensation. EME implemented SFAS No. 123(R) in the first quarter of 2006 and applied the modified prospective transition method. Under the modified prospective method, SFAS No. 123(R) was applied effective January 1, 2006 to the unvested portion of awards previously granted and will be applied to all prospective awards. Prior financial statements were not restated under this method. SFAS No. 123(R) resulted in the recognition of expense for all stock-based compensation awards. In addition, EME elected to calculate the pool of windfall tax benefits as of the adoption of SFAS No. 123(R) based on the method (also known as the short-cut method) proposed in FSP FAS 123(R)-3, "Transition Election to Accounting for the Tax Effects of Share-Based Payment Awards." Prior to January 1, 2006, EME used the intrinsic value method of accounting, which resulted in no recognition of expense for Edison International stock options. Prior to adoption of SFAS No. 123(R), EME presented all tax benefits of deductions resulting from the exercise of stock options as a component of operating cash flows under the caption "Other operating—liabilities" in the consolidated statements of cash flows. SFAS No. 123(R) requires the cash flows resulting from the tax benefits that occur from estimated tax deductions in excess of the compensation cost recognized for those options (excess tax benefits) to be classified as financing cash flows. The $7 million excess tax benefit is classified as a financing cash inflow in 2006.

Due to the adoption of SFAS No. 123(R), EME recorded a cumulative effect adjustment that increased net income by approximately $0.4 million, net of tax, in the first quarter of 2006, mainly to reflect the change in the valuation method for performance shares classified as liability awards and the use of forfeiture estimates.

FASB Staff Position FIN 46(R)-6

In April 2006, the FASB issued Staff Position FIN 46(R)-6, "Determining Variability to be Considered in Applying FIN 46(R)." FIN 46(R)-6 states that the variability to be considered in applying FIN 46(R) shall be based on an analysis of the design of the entity following a two-step process. The first step is to analyze the nature of the risks in the entity. The second step would be to determine the purpose(s) for which the entity was created and determine the variability (created by the risks identified in Step 1) the entity is designed to create and pass along to its interest holders. The guidance in this FASB Staff Position was effective prospectively beginning July 1, 2006, although companies had until December 31, 2006 to elect retrospective applications. EME adopted FIN 46(R)-6 prospectively beginning July 1, 2006. Applying the guidance had no effect on EME's consolidated financial statements for the year ending December 31, 2006.

Statement of Financial Accounting Standards No. 158

In September 2006, the FASB issued SFAS No. 158, which amends the accounting by employers for defined benefit pension plans and postretirement benefits other than pensions. SFAS No. 158 requires companies to recognize the overfunded or underfunded status of a defined benefit pension and other postretirement plans as assets or liabilities in their balance sheet; the assets or liabilities are offset through other comprehensive income. EME adopted SFAS No. 158 prospectively on December 31, 2006. SFAS No. 158 also requires companies to align the measurement dates for their plans to their fiscal year-ends; EME already has a fiscal year-end measurement date for all of its postretirement plans. Upon adoption, EME recorded additional postretirement benefit liabilities of $10 million (included in other long-term liabilities) and a reduction to accumulated other comprehensive income (a component of shareholder's equity) of $6 million, net of tax.

Staff Accounting Bulletin No. 108

In September 2006, the SEC issued Staff Accounting Bulletin (SAB) No. 108, which provides interpretive guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. SAB No. 108 requires additional quantitative testing to determine whether a misstatement is material. EME implemented SAB No. 108 for the filing of its Annual Report on Form 10-K for the year ended December 31, 2006. Applying the guidance had no effect on EME's consolidated financial statements for the year ended December 31, 2006.

Accounting Principles Not Yet Adopted

Statement of Financial Accounting Standards Interpretation No. 48

In July 2006, the FASB issued SFAS Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," that clarifies the accounting for uncertain tax positions. An enterprise would be required to recognize, in its financial statements, the best estimate of the impact of a tax position by determining if the weight of the available evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained on audit. EME will adopt the new interpretation in the first quarter of 2007. The new interpretation is not expected to result in a material adjustment to shareholder's equity.

Statement of Financial Accounting Standards No. 155

In February 2006, the FASB issued SFAS No. 155, which amends SFAS No. 133 and SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities." SFAS No. 155 allows financial instruments that have embedded derivatives to be accounted for at fair value at acquisition, at issuance, or when a previously recognized financial instrument is subject to a remeasurement event, on an instrument-by-instrument basis, in cases in which a derivative would otherwise have to be bifurcated. SFAS No. 155 is effective for all financial instruments acquired, issued, or subject to remeasurement after January 1, 2007. The fair value election provided for in paragraph 4(c) of this Statement may also be applied upon adoption of this Statement for hybrid financial instruments that had been bifurcated under paragraph 12 of SFAS No. 133 prior to the adoption of this Statement. EME does not expect the adoption of this standard to have a material impact on EME's consolidated financial statements.

Statement of Financial Accounting Standards No. 157

In September 2006, the FASB issued a new accounting standard on fair value measurements (SFAS No. 157). SFAS No. 157 clarifies the definition of fair value, establishes a framework for measuring fair value and expands the disclosures on fair value measurements. EME will adopt SFAS No. 157 on January 1, 2008. EME is currently evaluating the impact of adopting SFAS No. 157 on its consolidated financial statements.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of liquidity and capital resources is organized in the following sections:

EME's Liquidity

At December 31, 2006, EME and its subsidiaries had cash and cash equivalents and short-term investments of $1.8 billion, and EME had a total of $968 million of available borrowing capacity under its $500 million corporate credit facility and a $500 million working capital facility at Midwest Generation. EME's consolidated debt at December 31, 2006 was $3.2 billion. In addition, EME's subsidiaries had $4.2 billion of long-term lease obligations related to the sale-leaseback transactions that are due over periods ranging up to 28 years.

EME Financing Developments

During June 2006, EME replaced its $98 million credit agreement with a new credit agreement that provides for a $500 million senior secured revolving loan and letter of credit facility and matures on June 15, 2012. As security for its obligations under this credit facility, EME pledged its ownership interests in the holding companies through which it owns its interests in the Illinois Plants, the Homer City facilities, the Westside projects and the Sunrise project. EME also granted a security interest in an account into which all distributions received by it from the Big 4 projects will be deposited. EME will be free to use these proceeds unless an event of default occurs under the credit facility.

Also in June 2006, EME completed a private offering of $500 million aggregate principal amount of its 7.50% senior notes due June 15, 2013 and $500 million aggregate principal amount of its 7.75% senior notes due June 15, 2016. EME pays interest on the senior notes on June 15 and December 15 of each year, beginning on December 15, 2006. The senior notes are redeemable by EME at any time at a price equal to 100% of the principal amount of, plus accrued and unpaid interest and liquidated damages, if any, on the senior notes plus a "make-whole" premium. During the fourth quarter of 2006, EME completed an exchange of the senior notes issued in the private offering for new senior notes (with the same terms and conditions as the existing senior notes) registered under the Securities Act. EME used the net proceeds of the offering of the senior notes, together with cash on hand, to repay debt.

Capital Expenditures

At December 31, 2006, the three-year estimated capital expenditures by EME's subsidiaries related to existing projects, corporate activities and turbine commitments were as follows:

	2007	2008	2009
		(in millions)	
Illinois Plants			
Plant capital expenditures	$ 54	$ 45	$ 26
Environmental expenditures	21	38	66
Homer City Facilities			
Plant capital expenditures	19	26	20
Environmental expenditures	9	9	15
Wind Projects			
Projects under construction	176	—	—
Turbine commitments	463	26	—
Corporate capital expenditures	19	7	7
Total	$ 761	$ 151	$ 134

Expenditures for Existing Projects

Plant capital expenditures relate to non-environmental projects such as upgrades to boiler and turbine controls and dust collection/mitigation systems, a spare main power transformer, railroad interconnection and an expansion of a coal cleaning plant refuse site. Environmental expenditures relate to environmental projects such as mercury emission monitoring and control and SCR performance improvements at the Homer City facilities and various projects at the Illinois Plants to achieve specified emissions reductions such as installation of mercury controls. EME plans to finance these expenditures with financings, cash on hand or cash generated from operations. See further discussion regarding these and possible additional capital expenditures, including environmental control equipment at the Homer City facilities, under "Management's Overview—Business Strategy," "—Environmental Matters and Regulations—Air Quality Regulation—Clean Air Act—Illinois" and "—Environmental Matters and Regulations—Air Quality Regulation—Mercury Regulation."

Expenditures for New Projects

EME expects to make substantial investments in new projects during the next three years. In addition to the capital expenditures to purchase turbines set forth in the above table, EME has entered into an agreement to purchase 60 additional turbines (totaling 150 MW) subsequent to December 31, 2006, subject to certain conditions, and has entered into a letter of intent to purchase 300 turbines (totaling 630 MW) for delivery in 2008 and 2009. The purchase of these turbines is subject to completion of a definitive turbine purchase agreement. Total capital expenditures under these agreements would be approximately $875 million, not including the cost to complete construction, if the maximum number of turbines were purchased.

EME's Historical Consolidated Cash Flow

Consolidated Cash Flows from Operating Activities

Net cash provided by (used in) operating activities:

	Years Ended December 31,		
	2006	2005	2004
	(in millions)		
Continuing operations	$ 1,131	$ (239)	$ (353)
Discontinued operations	94	20	(434)
	$ 1,225	$ (219)	$ (787)

The 2006 increase in cash provided by operating activities from continuing operations was primarily attributable to a decrease of $625 million in required margin and collateral deposits in 2006 for EME's hedging and trading activities, compared to an increase of $656 million in 2005. This change resulted from a decrease in forward market prices in 2006 from 2005 and settlement of hedge contracts during 2006.

The 2005 decrease in cash used in operating activities from continuing operations was primarily attributable to the $960 million lease termination payment in 2004 related to the Collins Station lease and improved operating income in 2005. Partially offsetting these decreases was $656 million in required margin and collateral deposits in 2005 for EME's hedging and trading activities, compared to $30 million in 2004. This increase in margin and collateral deposits resulted from an increase in forward market prices.

Cash provided by operating activities from discontinued operations increased in 2006 from 2005 reflecting higher distributions received in 2006 compared to 2005 from the Lakeland power project. See "Results of Operations—Results of Discontinued Operations—Lakeland Project" for more information regarding these distributions. Cash used in operating activities from discontinued operations in 2004 primarily reflects settlement of working capital items from the sale of EME's international operations.

Consolidated Cash Flows from Financing Activities

Net cash used in financing activities:

	Years Ended December 31,		
	2006	2005	2004
	(in millions)		
Continuing operations	$ (461)	$ (773)	$ (21)
Discontinued operations	—	—	(144)
	$ (461)	$ (773)	$ (165)

The 2006 decrease in cash used in financing activities from continuing operations was primarily attributable to net proceeds of $1 billion received from EME's issuance of senior notes in 2006, which were mostly used to repay $1 billion of EME's outstanding senior notes and $139 million paid for tender premiums and related fees. In addition, dividend payments were made to MEHC of $360 million in 2005 compared to $51 million in 2006. In 2006, Midwest Generation also had net repayments of $170 million under its credit facility.

The 2005 increase in cash used in financing activities from continuing operations was primarily attributable to dividend payments made to MEHC of $360 million during 2005, compared to $74 million during 2004. The increase was also due to the repayment of EME's junior subordinated debentures of $150 million in January 2005 and a $302 million repayment in April 2005 related to Midwest Generation's existing term loan.

Cash used in financing activities from discontinued operations in 2004 primarily reflects repayment of debt and dividends to minority shareholders.

Consolidated Cash Flows from Investing Activities

Net cash provided by (used in) investing activities:

	Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Continuing operations	$ (706)	$ (134)	$ 2,707
Discontinued operations	—	5	18
	$ (706)	$ (129)	$ 2,725

The 2006 increase in cash used in investing activities from continuing operations was primarily due to net purchases of marketable securities of $375 million in 2006, compared to $43 million in 2005. In addition, EME paid $18 million towards the purchase price of the Wildorado wind project during 2006, incurred higher capital expenditures in 2006 and received lower proceeds from sales of projects.

The 2005 increase in cash used in investing activities from continuing operations was primarily attributable to proceeds of $2.7 billion received in 2004 from the sale of most of EME's international operations and $154 million paid towards the purchase price for the San Juan Mesa project in December 2005. Proceeds of $124 million received in 2005 from the sale of EME's 25% investment in the Tri Energy project and EME's 50% investment in the CBK project were comparable to proceeds of $118 million received in 2004. Partially offsetting the 2005 increase were net purchases of marketable securities of $43 million in 2005, compared to $120 million in 2004.

Credit Ratings

Overview

Credit ratings for EME and its subsidiaries, Midwest Generation and EMMT, at December 31, 2006, were as follows:

	Moody's Rating	S&P Rating
EME	B1	BB-
Midwest Generation:		
First priority senior secured rating	Baa3	BB
Second priority senior secured rating	Ba2	B+
EMMT	Not Rated	BB-

On September 27, 2006, Moody's raised Midwest Generation's first priority senior secured rating to Baa3 from Ba2 and its second priority senior secured rating to Ba2 from Ba3. On September 29, 2006, S&P raised the credit ratings of EME and EMMT to BB-from B+. S&P also raised Midwest Generation's first priority senior secured rating to BB from BB- and its second priority senior secured rating to B+ from B.

EME cannot provide assurance that its current credit ratings or the credit ratings of its subsidiaries will remain in effect for any given period of time or that one or more of these ratings will not be lowered. EME notes that these credit ratings are not recommendations to buy, sell or hold its securities and may be revised at any time by a rating agency.

EME does not have any "rating triggers" contained in subsidiary financings that would result in it being required to make equity contributions or provide additional financial support to its subsidiaries.

Credit Rating of EMMT

The Homer City sale-leaseback documents restrict EME Homer City's ability to enter into trading activities, as defined in the documents, with EMMT to sell forward the output of the Homer City facilities if EMMT does not have an investment grade credit rating from S&P or Moody's or, in the absence of those ratings, if it is not rated as investment grade pursuant to EME's internal credit scoring procedures. These documents include a requirement that the counterparty to such transactions, and EME Homer City, if acting as seller to an unaffiliated third party, be investment grade. EME currently sells all the output from the Homer City facilities through EMMT, which has a below investment grade credit rating, and EME Homer City is not rated. Therefore, in order for EME to continue to sell forward the output of the Homer City facilities, either: (1) EME must obtain consent from the sale-leaseback owner participant to permit EME Homer City to sell directly into the market or through EMMT; or (2) EMMT must provide assurances of performance consistent with the requirements of the sale-leaseback documents. EME has obtained a consent from the sale-leaseback owner participant that will allow EME Homer City to enter into such sales, under specified conditions, through December 31, 2008. EME Homer City continues to be in compliance with the terms of the consent. EME is permitted to sell the output of the Homer City facilities into the spot market at any time. See "Market Risk Exposures—Commodity Price Risk—Energy Price Risk Affecting Sales from the Homer City Facilities."

Margin, Collateral Deposits and Other Credit Support for Energy Contracts

In connection with entering into contracts in support of EME's hedging and energy trading activities (including forward contracts, transmission contracts and futures contracts), EME's subsidiary, EMMT, has entered into agreements to mitigate the risk of nonperformance. Because the credit ratings of EMMT and EME are below investment grade, EME has historically provided collateral in the form of cash and letters of credit for the benefit of counterparties related to accounts payable and unrealized losses in connection with these hedging and trading activities. At December 31, 2006, EMMT had deposited $31 million in cash with brokers in margin accounts in support of futures contracts and had deposited $42 million with counterparties in support of forward energy and transmission contracts. In addition, EME had issued letters of credit of $6 million in support of commodity contracts at December 31, 2006.

Future cash collateral requirements may be higher than the margin and collateral requirements at December 31, 2006, if wholesale energy prices increase or the amount hedged increases. EME estimates that margin and collateral requirements for energy contracts outstanding as of December 31, 2006 could increase by approximately $610 million over the remaining life of the contracts using a 95% confidence level.

Midwest Generation has cash on hand and a $500 million working capital facility to support margin requirements specifically related to contracts entered into by EMMT related to the Illinois Plants. At December 31, 2006, Midwest Generation had available $495 million of borrowing capacity under this credit facility. As of December 31, 2006, Midwest Generation had $43 million in loans receivable from EMMT for margin advances. In addition, EME has cash on hand and a $500 million working capital facility to provide credit support to subsidiaries. See "—EME Financing Developments" and "—EME's Liquidity as a Holding Company" for further discussion.

EME's Liquidity as a Holding Company

Overview

At December 31, 2006, EME had corporate cash and cash equivalents and short-term investments of $1.5 billion to meet liquidity needs. See "—EME's Liquidity." Cash distributions from EME's subsidiaries and partnership investments and unused capacity under its corporate credit facility represent EME's major sources of liquidity to meet its cash requirements. The timing and amount of distributions from EME's subsidiaries may be affected by many factors beyond its control. See "—Dividend Restrictions in Major Financings."

Historical Distributions Received By EME

The following table is presented as an aid in understanding the cash flow of EME's continuing operations and its various subsidiary holding companies which depend on distributions from subsidiaries and affiliates to fund general and administrative costs and debt service costs of recourse debt.

	Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Distributions from Consolidated Operating Projects:			
Edison Mission Midwest Holdings (Illinois Plants)	$ 542(1)	$ 330(2)	$ 88
EME Homer City (Homer City facilities)	—	86	61
Holding company for Storm Lake project	11	—	—
Holding companies of other consolidated operating projects	5	1	1
Distributions from Unconsolidated Operating Projects:			
Edison Mission Energy Funding Corp. (Big 4 Projects)(3)	116	122	108
Sunrise Power Company	22	20	19
Holding company for Doga project	—	17	15
Holding companies for Westside projects	16	17	18
Holding companies of other unconsolidated operating projects	1	5	3
Total Distributions	$ 713	$ 598	$ 313

(1) Subsequent to December 31, 2006, Edison Mission Midwest Holdings made an additional distribution of $117 million.

(2) In April 2005, EME made a capital contribution of $300 million which was used to repay debt.

(3) The Big 4 projects consist of investments in the Kern River project, Midway-Sunset project, Sycamore project and Watson project. Distributions reflect the amount received by EME after debt service payments by Edison Mission Energy Funding Corp.

Intercompany Tax-Allocation Agreement

EME is included in the consolidated federal and combined state income tax returns of Edison International and is eligible to participate in tax-allocation payments with other subsidiaries of Edison International in circumstances where domestic tax losses are incurred. The right of EME to receive and the amount of and timing of tax-allocation payments are dependent on the inclusion of EME in the consolidated income tax returns of Edison International and its subsidiaries and other factors, including the consolidated taxable income of Edison International and its subsidiaries, the amount of net operating losses and other tax items of EME, its subsidiaries, and other subsidiaries of Edison International and specific procedures regarding allocation of state taxes. EME receives tax-allocation payments for tax losses when and to the extent that the consolidated Edison International group generates sufficient taxable income in order to be able to utilize EME's consolidated tax losses in the consolidated income tax returns for Edison International and its subsidiaries. Based on the application of the factors cited above, EME is obligated during periods it generates taxable income to make payments under the tax-allocation agreements. EME made net tax-allocation payments to Edison International of $151 million and $129 million in 2006 and 2005, respectively.

Dividend Restrictions in Major Financings

General

Each of EME's direct or indirect subsidiaries is organized as a legal entity separate and apart from EME and its other subsidiaries. Assets of EME's subsidiaries are not available to satisfy EME's obligations or the obligations of any of its other subsidiaries. However, unrestricted cash or other assets that are available for distribution may, subject to applicable law and the terms of financing arrangements of the parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to EME or to its subsidiary holding companies.

Key Ratios of EME's Principal Subsidiaries Affecting Dividends

Set forth below are key ratios of EME's principal subsidiaries required by financing arrangements for the twelve months ended December 31, 2006:

Subsidiary	Financial Ratio	Covenant	Actual
Midwest Generation (Illinois Plants)	Interest Coverage Ratio	Greater than or equal to 1.40 to 1	5.14 to 1
Midwest Generation (Illinois Plants)	Secured Leverage Ratio	Less than or equal to 7.25 to 1	2.17 to 1
EME Homer City (Homer City facilities)	Senior Rent Service Coverage Ratio	Greater than 1.7 to 1	2.32 to 1(1)

(1) The senior rent service coverage ratio is determined by dividing net operating cash flow by senior rent. Net operating cash flow represents revenues less operating expenses as defined in the sale-leaseback documents. Revenue during the twelve months ended December 31, 2006 includes $15.5 million from an advance payment from EMMT against future deliveries of power to it under its trading arrangements with EME Homer City.

Midwest Generation Financing Restrictions on Distributions

Midwest Generation is bound by the covenants in its credit agreement and indenture as well as certain covenants under the Powerton-Joliet lease documents with respect to Midwest Generation making payments under the leases. These covenants include restrictions on the ability to, among other things, incur debt, create liens on its property, merge or consolidate, sell assets, make investments, engage in transactions with affiliates, make distributions, make capital expenditures, enter into agreements restricting its ability to make distributions, engage in other lines of business or engage in transactions for any speculative purpose. In addition, the credit agreement contains financial covenants binding on Midwest Generation.

Covenants in Credit Agreement

In order for Midwest Generation to make a distribution, it must be in compliance with covenants specified under its credit agreement. Compliance with the covenants in its credit agreement includes maintaining the following two financial performance requirements:

- At the end of each fiscal quarter, Midwest Generation's consolidated interest coverage ratio for the immediately preceding four consecutive fiscal quarters must be at least 1.40 to 1. The consolidated interest coverage ratio is defined as the ratio of consolidated net income (plus or minus specified amounts as set forth in the credit agreement), to consolidated interest expense (as more specifically defined in the credit agreement).
- Midwest Generation's secured leverage ratio for the 12-month period ended on the last day of the immediately preceding fiscal quarter may be no greater than 7.25 to 1. The secured leverage ratio is defined as the ratio of the aggregate principal amount of Midwest Generation secured debt plus all indebtedness of a subsidiary of Midwest Generation, to the aggregate amount of consolidated net income (plus or minus specified amounts as set forth in the credit agreement).

In addition, Midwest Generation's distributions are limited in amount. Under the terms of Midwest Generation's credit agreement, Midwest Generation is permitted to distribute 75% of its excess cash flow (as defined in the credit agreement). In addition, if equity is contributed to Midwest Generation, Midwest Generation is permitted to distribute 100% of excess cash flow until the aggregate portion of distributions that Midwest Generation attributed to the equity contribution equals the amount of the equity contribution. Because EME made a $300 million equity contribution to Midwest Generation on April 19, 2005, Midwest Generation is permitted to distribute 100% of excess cash flow until the aggregate portion of such distributions attributed to that equity contribution equals $300 million. After taking into account Midwest Generation's most recent distribution in January 2007, $58 million of the equity contribution is still available for this purpose. To the extent Midwest Generation makes a distribution which is not fully attributed to an equity contribution, Midwest Generation is required to make concurrently with such distribution an offer to repay debt in an amount equal to the excess, if any, of one-third of such distribution over the amount attributed to the equity contribution.

Covenants in Indenture

Midwest Generation's indenture contains restrictions on its ability to make a distribution substantially similar to those in the credit agreement. Failure to achieve the conditions required for distributions will not result in a default under the indenture, nor does the indenture contain any other financial performance requirements.

EME Homer City (Homer City Facilities)

EME Homer City completed a sale-leaseback of the Homer City facilities in December 2001. In order to make a distribution, EME Homer City must be in compliance with the covenants specified in the lease agreements, including the following financial performance requirements measured on the date of distribution:

- At the end of each quarter, the senior rent service coverage ratio for the prior twelve-month period (taken as a whole) must be greater than 1.7 to 1. The senior rent service coverage ratio is defined as all income and receipts of EME Homer City less amounts paid for operating expenses, required capital expenditures, taxes and financing fees divided by the aggregate amount of the debt portion of the rent, plus fees, expenses and indemnities due and payable with respect to the lessor's debt service reserve letter of credit.

At the end of each quarter, the equity and debt portions of rent then due and payable must have been paid. The senior rent service coverage ratio (discussed above) projected for each of the prospective two twelve-month periods must be greater than 1.7 to 1. No more than two rent default events may have occurred, whether or not cured. A rent default event is defined as the failure to pay the equity portion of the rent within five business days of when it is due.

EME Corporate Credit Facility Restrictions on Distributions from Subsidiaries

EME's corporate credit facility contains covenants that restrict its ability, and the ability of several of its subsidiaries, to make distributions. This restriction binds the subsidiaries through which EME owns the Westside projects, the Sunrise project, the Illinois Plants, the Homer City facilities and the Big 4 projects. These subsidiaries would not be able to make a distribution to EME if an event of default were to occur and be continuing under EME's corporate credit facility after giving effect to the distribution.

In addition, EME granted a security interest in an account into which all distributions received by it from the Big 4 projects are deposited. EME is free to use these distributions unless and until an event of default occurs under its corporate credit facility.

As of December 31, 2006, EME had no borrowings and $27 million of letters of credit outstanding under this credit facility.

Contractual Obligations, Commitments and Contingencies

Contractual Obligations

The following table summarizes EME's significant consolidated contractual obligations as of December 31, 2006.

		Payments Due by Period (in millions)			
Contractual Obligations	**Total**	**Less than 1 year**	**1 to 3 years**	**3 to 5 years**	**More than 5 years**
Long-term debt(1)	$ 4,692	$ 375	$ 1,089	$ 716	$ 2,512
Operating lease obligations	4,407	360	713	664	2,670
Purchase obligations:					
Capital improvements	186	186	—	—	—
Turbine commitments	489	463	26	—	—
Fuel supply contracts	685	365	239	71	10
Gas transportation agreements	92	8	16	16	52
Coal transportation	455	220	159	76	—
Other contractual obligations	43	11	22	10	—
Employee benefit plan contribution(2)	15	15	—	—	—
Total Contractual Obligations	$11,064	$ 2,003	$ 2,264	$ 1,553	$ 5,244

(1) See "Edison Mission Energy and Subsidiaries Notes to Consolidated Financial Statements—Note 8. Financial Instruments" for additional details. Table assumes long-term debt is held to maturity, except the Midwest Generation senior secured notes which are assumed to be held until 2014. Amount also includes interest payments over applicable period of the debt.

(2) Amount includes estimated contribution for pension plans and postretirement benefits other than pensions. The estimated contributions beyond 2007 are not available. For more information, see "Edison Mission Energy and Subsidiaries Notes to Consolidated Financial Statements—Note 11. Compensation and Benefit Plans—Pension Plans and Postretirement Benefits Other Than Pensions."

Operating Lease Obligations

At December 31, 2006, minimum operating lease payments were primarily related to long-term leases for the Powerton and Joliet Stations and the Homer City facilities. During 2000, EME entered into sale-leaseback transactions for two power facilities, the Powerton and Joliet coal-fired stations located in Illinois, with third-party lessors. During the fourth quarter of 2001, EME entered into a sale-leaseback transaction for the Homer City coal-fired facilities located in Pennsylvania, with third-party lessors. Total minimum lease payments during the next five years are $336 million in 2007, $337 million in 2008, $336 million in 2009, $325 million in 2010, $312 million in 2011, and the minimum lease payments due after 2011 are $2.6 billion. For further discussion, see "—Off-Balance Sheet Transactions—Sale-Leaseback Transactions."

Purchase Obligations

Capital Improvements

At December 31, 2006, EME's subsidiaries had firm commitments for capital and construction expenditures. The majority of these expenditures relate to the construction of the 161 MW Wildorado wind project and four other wind projects totaling 181 MW. Also included are expenditures for dust collection and mitigation system and various other smaller projects. These expenditures are planned to be financed by cash on hand, cash generated from operations or existing subsidiary credit agreements.

Turbine Commitments

At December 31, 2006, EME had entered into agreements with vendors securing 255 wind turbines (487 MW) with remaining commitments of $387 million in 2007 and $23 million in 2008. In addition, EME had entered into an agreement for the purchase of five gas turbines and related equipment for an aggregate purchase price of approximately $140 million with remaining commitments of $76 million in 2007 and $3 million in 2008. In February 2007, EME was advised that it was an unsuccessful bidder in the request for offers conducted by SCE for the supply of generation capacity. EME plans to use the turbines which it had purchased and reserved for this bid for other generation supply opportunities.

Fuel Supply Contracts

At December 31, 2006, Midwest Generation and EME Homer City had contractual commitments to purchase coal with various third-party suppliers. The remaining contracts' lengths range from less than one year to six years. The minimum commitments are based on the contract provisions, which consist of fixed prices, subject to adjustment clauses. For further discussion, see "—Market Risk Exposures—Commodity Price Risk—Coal Price Risk."

Gas Transportation Agreements

At December 31, 2006, EME had a contractual commitment to transport natural gas. EME is committed to pay its share of fixed monthly capacity charges under its gas transportation agreement, which has a remaining contract length of 11 years.

Coal Transportation Agreements

At December 31, 2006, EME's subsidiaries had contractual commitments for the transport of coal to their respective facilities, with remaining contract lengths that range from one year to five years. Midwest Generation's primary contract is with Union Pacific Railroad (and various delivering carriers) which extends through 2011. Midwest Generation commitments under this agreement are based on actual coal purchases from the PRB. Accordingly, Midwest Generation's contractual obligations for transportation are based on coal volumes set forth in their fuel supply contracts. EME Homer City commitments under its agreements are based on the contract provisions, which consist of fixed prices, subject to adjustment clauses. Although trucking remains the predominant mode of transportation for coal shipments to the Homer City facilities, rail transportation is expected to increase in 2007 as EME Homer City diversifies its alternative modes of transporting coal to the plant site.

Commercial Commitments

Standby Letters of Credit

As of December 31, 2006, standby letters of credit aggregated to $34 million and were scheduled to expire in 2007.

Guarantees and Indemnities

Tax Indemnity Agreements—

In connection with the sale-leaseback transactions that EME has entered into related to the Powerton and Joliet Stations in Illinois, the Collins Station in Illinois, and the Homer City facilities in Pennsylvania, EME and several of its subsidiaries entered into tax indemnity agreements. Under these tax indemnity agreements, these entities agreed to indemnify the lessors in the sale-leaseback transactions for specified adverse tax consequences that could result in certain situations set forth in each tax indemnity agreement, including specified defaults under the respective leases. The potential indemnity obligations under these tax indemnity agreements could be significant. Due to the nature of these potential obligations, EME cannot determine a maximum potential liability which would be triggered by a valid claim from the lessors. EME has not recorded a liability related to these indemnities. In connection with the termination of the Collins Station lease in April 2004, Midwest Generation will continue to have obligations under the tax indemnity agreement with the former lease equity investor. For more information about the termination of the Collins Station lease, see "Edison Mission Energy and Subsidiaries Notes to Consolidated Financial Statements—Note 2. Restructuring, Loss on Lease Termination, Asset Impairment and Other Charges."

Indemnities Provided as Part of the Acquisition of the Illinois Plants—

In connection with the acquisition of the Illinois Plants, EME agreed to indemnify Commonwealth Edison with respect to specified environmental liabilities before and after December 15, 1999, the date of sale. The indemnification claims are reduced by any insurance proceeds and tax benefits related to such claims and are subject to a requirement that Commonwealth Edison take all reasonable steps to mitigate losses related to any such indemnification claim. Due to the nature of the obligation under this indemnity, a maximum potential liability cannot be determined. This indemnification for environmental liabilities is not limited in term and would be triggered by a valid claim from Commonwealth Edison. Except as discussed below, EME has not recorded a liability related to this indemnity.

Midwest Generation entered into a supplemental agreement with Commonwealth Edison and Exelon Generation on February 20, 2003 to resolve a dispute regarding interpretation of its reimbursement obligation for asbestos claims under the environmental indemnities set forth in the Asset Sale Agreement. Under this supplemental agreement, Midwest Generation agreed to reimburse Commonwealth Edison and Exelon Generation for 50% of specific asbestos claims pending as of February 2003 and related expenses less recovery of insurance costs, and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement. As a general matter, Commonwealth Edison and Midwest Generation apportion responsibility for future asbestos-related claims based upon the number of exposure sites that are Commonwealth Edison locations or Midwest Generation locations. The obligations under this agreement are not subject to a maximum liability. The supplemental agreement has a five-year term with an automatic renewal provision (subject to the right of either party to terminate). Payments are made under this indemnity upon tender by Commonwealth Edison of appropriate proof of liability for an asbestos-related settlement, judgment, verdict, or expense. There were approximately 186 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed at December 31, 2006. Midwest Generation had recorded a $65 million liability at December 31, 2006 related to this matter.

The amounts recorded by Midwest Generation for the asbestos-related liability are based upon a number of assumptions. Future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding asbestos litigation in the United States, could cause the actual costs to be higher or lower than projected.

Indemnity Provided as Part of the Acquisition of the Homer City Facilities—

In connection with the acquisition of the Homer City facilities, EME Homer City agreed to indemnify the sellers with respect to specific environmental liabilities before and after the date of sale. Payments would be triggered under this indemnity by a claim from the sellers. EME guaranteed the obligations of EME Homer City. Due to the nature of the obligation under this indemnity provision, it is not subject to a maximum potential liability and does not have an expiration date. EME has not recorded a liability related to this indemnity.

Indemnities Provided under Asset Sale Agreements—

The asset sale agreements for the sale of EME's international assets contain indemnities from EME to the purchasers, including indemnification for taxes imposed with respect to operations of the assets prior to the sale and for pre-closing environmental liabilities. Not all indemnities under the asset sale agreements have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. At December 31, 2006, EME had recorded a liability of $95 million related to these matters.

In connection with the sale of various domestic assets, EME has from time to time provided indemnities to the purchasers for taxes imposed with respect to operations of the asset prior to the sale. EME has also provided indemnities to purchasers for items specified in each agreement (for example, specific pre-existing litigation matters and/or environmental conditions). Due to the nature of the obligations under these indemnity agreements, a maximum potential liability cannot be determined. Not all indemnities under the asset sale agreements have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. EME has not recorded a liability related to these indemnities.

Capacity Indemnification Agreements—

EME has guaranteed, jointly and severally with Texaco Inc., the obligations of March Point Cogeneration Company under its project power sales agreements to repay capacity payments to the project's power purchaser in the event that the power sales agreements terminate, March Point Cogeneration Company abandons the project, or the project fails to return to normal operations within a reasonable time after a complete or partial shutdown, during the term of the power sales agreements. In addition, a subsidiary of EME has guaranteed the obligations of Sycamore Cogeneration Company under its project power sales agreement to repay capacity payments to the project's power purchaser in the event that the project unilaterally terminates its performance or reduces its electric power producing capability during the term of the power sales agreement. The obligations under the indemnification agreements as of December 31, 2006, if payment were required, would be $101 million. EME has not recorded a liability related to these indemnities.

Subsidiary Guarantee for Performance of Unconsolidated Affiliate—

A subsidiary of EME has guaranteed the obligations of an unconsolidated affiliate to make payments to a third party for power delivered under a fixed-price power sales agreement that expires in August 2007. EME believes there is sufficient cash flow to pay the power suppliers, assuming timely payment by the power purchasers. Due to the nature of this indemnity, a maximum potential liability cannot be determined. To the extent EME's subsidiary would be required to make payments under the guarantee, EME's subsidiary and EME are indemnified by Peabody Energy Corporation pursuant to the 2000 Purchase and Sale Agreement for Citizens Power LLC. EME's subsidiary has not recorded a liability related to this indemnity.

Contingencies

FERC Notice Regarding Investigatory Proceeding against EMMT

At the end of October 2006, EMMT was advised by the enforcement staff at the FERC that it is prepared to recommend that the FERC initiate a formal investigatory proceeding and seek monetary sanctions against EMMT for alleged violation of the FERC's rules with respect to certain bidding practices employed by EMMT. EMMT is engaged in discussions with the staff to explore the possibility of resolution of this matter. Should a formal proceeding be commenced, EMMT will be entitled to contest any alleged violations before the FERC and an appropriate court. EME believes that EMMT has complied with the FERC's rules and intends to contest vigorously any allegation of violation. EME cannot predict at this time the outcome of this matter or estimate the possible liability should the outcome be adverse.

Midway-Sunset Cogeneration Company

San Joaquin Energy Company, a wholly owned subsidiary of EME, owns a 50% general partnership interest in Midway-Sunset Cogeneration Company, which owns a 225 MW cogeneration facility near Fellows, California. Midway-Sunset is a party to several proceedings pending at the FERC involving claims for refunds from entities that sold power and related services into the California markets operated by the California Power Exchange and the California Independent System Operator (collectively the California Markets) at prices that were allegedly not just and reasonable, as required by the Federal Power Act.

Midway-Sunset is a party to these proceedings because Midway-Sunset was a seller in the California Markets during 2000 and 2001, both for its own account and on behalf of SCE and PG&E, the utilities to which the majority of Midway-Sunset's power was contracted for sale. As a seller into the California Markets, Midway-Sunset is potentially liable for refunds to purchasers in these markets.

The claims asserted against Midway-Sunset for refunds related to power sold into the California Markets, including power sold on behalf of SCE and PG&E, are estimated to be less than $70 million for all periods under consideration. Midway-Sunset has calculated its potential liability for refunds related to power sold into the California Markets on its own behalf (excluding power sold on behalf of SCE and PG&E) to be approximately $0.5 million for the period October 2, 2000 through June 20, 2001. Midway Sunset's potential liability for sales on its own behalf during the period May 1, 2000 through October 1, 2000 has not yet been calculated but is not expected to be material. These calculations were made in accordance with the methodology approved by the FERC, but it is possible that this methodology will be challenged.

Because Midway-Sunset did not retain any proceeds from power sold into the California Markets on behalf of SCE and PG&E in excess of the amounts to which it was entitled under the pre-existing power sales contracts, but instead passed those proceeds on to the utilities, EME believes that PG&E and SCE are obligated to reimburse Midway-Sunset for any refund liability that it incurs as a result of sales made into the California Markets on their behalf. Midway-Sunset intends vigorously to assert these positions. However, at this time EME cannot predict the outcome of this matter.

Insurance

On January 29, 2006, the main power transformer on Unit 3 of the Homer City facilities failed, resulting in a suspension of operations at this unit. EME Homer City secured a replacement transformer and Unit 3 returned to service on May 5, 2006. The main transformer failure resulted in claims under EME Homer City's property and business interruption insurance policies. At December 31, 2006, EME Homer City had a $17 million receivable, of which $11 million relates to business interruption insurance coverage and has been reflected in other income (expense), net in EME's consolidated income statements. In January 2007, EME Homer City received a $3.5 million cash payment related to the replacement transformer.

Tax Matters

EME is, and may in the future be, under examination by tax authorities in varying tax jurisdictions with respect to positions it takes in connection with the filing of its tax returns. Matters raised upon audit may involve substantial amounts, which, if resolved unfavorably, an event not currently anticipated, could possibly be material. However, in EME's opinion, it is unlikely that the resolution of any such matters will have a material adverse effect upon EME's financial condition or results of operations.

Litigation

EME experiences other routine litigation in the normal course of its business. None of such pending routine litigation is expected to have a material adverse effect on EME's consolidated financial position or results of operations.

Off-Balance Sheet Transactions

Introduction

EME has off-balance sheet transactions in two principal areas: investments in projects accounted for under the equity method and operating leases resulting from sale-leaseback transactions.

Investments Accounted for under the Equity Method

EME has a number of investments in power projects that are accounted for under the equity method. Under the equity method, the project assets and related liabilities are not consolidated in EME's consolidated balance sheet. Rather, EME's financial statements reflect its investment in each entity and it records only its proportionate ownership share of net income or loss. These investments are of three principal categories.

Historically, EME has invested in qualifying facilities, those which produce electrical energy and steam, or other forms of energy, and which meet the requirements set forth in PURPA. See "Item 1. Business—Regulatory Matters—U.S. Federal Energy Regulation." Prior to the passage of the EPAct 2005, these regulations limited EME's ownership interest in qualifying facilities to no more than 50% due to EME's affiliation with SCE, a public utility. For this reason, EME owns a number of domestic energy projects through partnerships in which it has a 50% or less ownership interest.

Entities formed to own these projects are generally structured with a management committee or board of directors in which EME exercises significant influence but cannot exercise unilateral control over the operating, funding or construction activities of the project entity. EME's energy projects have generally secured long-term debt to finance the assets constructed and/or acquired by them. These financings generally are secured by a pledge of the assets of the project entity, but do not provide for any recourse to EME. Accordingly, a default on a long-term financing of a project could result in foreclosure on the assets of the project entity resulting in a loss of some or all of EME's project investment, but would generally not require EME to contribute additional capital. At December 31, 2006, entities which EME has accounted for under the equity method had indebtedness of $524 million, of which $252 million is proportionate to EME's ownership interest in these projects.

Sale-Leaseback Transactions

EME has entered into sale-leaseback transactions related to the Powerton and Joliet Stations in Illinois and the Homer City facilities in Pennsylvania. See "—Contractual Obligations, Commitments and Contingencies—Contractual Obligations—Operating Lease Obligations." Each of these transactions was completed and accounted for in accordance with SFAS No. 98, which requires, among other things, that all the risk and rewards of ownership of assets be transferred to a new owner without continuing involvement in the assets by the former owner other than as normal for a lessee. These transactions were entered into to provide a source of capital either to fund the original acquisition of the assets or to repay indebtedness previously incurred for the acquisition. In each of these transactions, the assets were sold to and then leased from owner/lessors owned by independent equity investors. In addition to the equity invested in them, these owner/lessors incurred or assumed long-term debt, referred to as lessor debt, to finance the purchase of the assets. The lessor debt takes the form generally referred to as secured lease obligation bonds.

EME's subsidiaries account for these leases as financings in their separate financial statements due to specific guarantees provided by EME or another one of its subsidiaries as part of the sale-leaseback transactions. These guarantees do not preclude EME from recording these transactions as operating leases in its consolidated financial statements, but constitute continuing involvement under SFAS No. 98 that precludes EME's subsidiaries from utilizing this accounting treatment in their separate subsidiary financial statements. Instead, each subsidiary continues to record the power plants as assets in a similar manner to a capital lease and records the obligations under the leases as lease financings. EME's subsidiaries, therefore, record depreciation expense from the power plants and interest expense from the lease financing in lieu of an operating lease expense which EME uses in preparing its consolidated financial statements. The treatment of these leases as an operating lease in its consolidated financial statements in lieu of a lease financing, which is recorded by EME's subsidiaries, resulted in an increase in consolidated net income by $61 million, $72 million and $73 million in 2006, 2005 and 2004, respectively.

The lessor equity and lessor debt associated with the sale-leaseback transactions for the Powerton, Joliet and Homer City assets are summarized in the following table:

Power Station(s)	Acquisition Price	Equity Investor	Original Equity Investment in Owner/Lessor	Amount of Lessor Debt at December 31, 2006	Maturity Date of Lessor Debt
			(in millions)		
Powerton/Joliet	$ 1,367	PSEG/ Citigroup, Inc.	$ 238	$ 330.8 Series A	2009
				679.1 Series B	2016
Homer City	1,591	GECC/ Metropolitan Life Insurance Company(1)	798	$ 276.0 Series A	2019
				521.2 Series B	2026

PSEG—PSEG Resources, Inc.
GECC—General Electric Capital Corporation

(1) On September 29, 2005, GECC sold 10% of its investment to Metropolitan Life Insurance Company.

The operating lease payments to be made by each of EME's subsidiary lessees are structured to service the lessor debt and provide a return to the owner/lessor's equity investors. Neither the value of the leased assets nor the lessor debt is reflected in EME's consolidated balance sheet. In accordance with GAAP, EME records rent expense on a levelized basis over the terms of the respective leases. To the extent that EME's cash rent payments exceed the amount levelized over the term of each lease, EME records prepaid rent. At December 31, 2006 and 2005, prepaid rent on these leases was $556 million and $395 million, respectively. To the extent that EME's cash rent payments are less than the amount levelized, EME reduces the amount of prepaid rent.

In the event of a default under the leases, each lessor can exercise all its rights under the applicable lease, including repossessing the power plant and seeking monetary damages. Each lease sets forth a termination value payable upon termination for default and in certain other circumstances, which generally declines over time and in the case of default may be reduced by the proceeds arising from the sale of the repossessed power plant. A default under the terms of the Powerton and Joliet or Homer City leases could result in a loss of EME's ability to use such power plant and would trigger obligations under EME's guarantee of the Powerton and Joliet leases. These events could have a material adverse effect on EME's results of operations and financial position.

EME's minimum lease obligations under its power related leases are set forth under "—Contractual Obligations, Commitments and Contingencies—Contractual Obligations—Operating Lease Obligations."

EME's Obligations to Midwest Generation

The proceeds, in the aggregate amount of approximately $1.4 billion, received by Midwest Generation from the sale of the Powerton and Joliet plants, described above under "Sale-Leaseback Transactions," were loaned to EME. EME used the proceeds from this loan to repay corporate indebtedness. Although interest and principal payments made by EME to Midwest Generation under this intercompany loan assist in the payment of the lease rental payments owing by Midwest Generation, the intercompany obligation does not appear on EME's consolidated balance sheet. This obligation was disclosed to the credit rating agencies at the time of the transaction and has been included by them in assessing EME's credit ratings. The following table summarizes principal payments due under this intercompany loan:

Years Ending December 31,	Principal Amount	Interest Amount	Total
		(in millions)	
2007	$ 3	$ 113	$ 116
2008	4	112	116
2009	5	112	117
2010	4	112	116
2011	9	111	120
Thereafter	1,334	401	1,735
Total	$ 1,359	$ 961	$ 2,320

EME funds the interest and principal payments due under this intercompany loan from distributions from EME's subsidiaries, including Midwest Generation, cash on hand, and amounts available under corporate lines of credit. A default by EME in the payment of this intercompany loan could result in a shortfall of cash available for Midwest Generation to meet its lease and debt obligations. A default by Midwest Generation in meeting its obligations could in turn have a material adverse effect on EME.

Environmental Matters and Regulations

Introduction

The construction and operation of power plants are subject to environmental regulation by federal, state and local authorities. EME believes that it is in substantial compliance with existing environmental regulatory requirements. Typically, environmental laws and regulations require a lengthy and complex process for obtaining licenses, permits and approvals prior to construction, operation or modification of a project or generating facility. Meeting all the necessary requirements can delay or sometimes prevent the completion of a proposed project, as well as require extensive modifications to existing projects, which may involve significant capital expenditures. If EME fails to comply with applicable environmental laws, it may be subject to injunctive relief or penalties and fines imposed by regulatory authorities.

Air Quality Regulation

Federal environmental regulations require reductions in emissions beginning in 2009 and require states to adopt implementation plans that are equal to or more stringent than the federal requirements. Compliance with these regulations and SIPs will affect the costs and the manner in which EME conducts its business, and will require EME to make substantial additional capital expenditures. There is no assurance that EME would be able to recover these increased costs from its customers or that EME's financial position and results of operations would not be materially adversely affected as a result.

Clean Air Act

On May 12, 2005, the CAIR was published in the Federal Register. The CAIR requires 28 eastern states and the District of Columbia to address ozone attainment issues by reducing regional NO_x and SO_2 emissions. The CAIR reduces the current Clean Air Act Title IV Phase II SO_2 emissions allowance cap for 2010 and 2015 by 50% and 65%, respectively. The CAIR also requires reductions in regional NO_x emissions in 2009 and 2015 by 53% and 61%, respectively, from 2003 levels. The CAIR has been challenged in court, which may result in changes to the substance of the rule and to the timetables for implementation.

EME expects that compliance with the CAIR and the regulations and revised SIPs developed as a consequence of the CAIR will result in increased capital expenditures and operating expenses. EME's approach to meeting these obligations will consist of a blending of capital expenditure and emission allowance purchases that will be based on an ongoing assessment of the dynamics of its market conditions.

Illinois—

On December 11, 2006, Midwest Generation entered into an agreement with the Illinois EPA to reduce mercury, NO_x and SO_2 emissions at the Illinois Plants. The agreement has been embodied in rule language, called the CPS, and Midwest Generation's obligations under the agreement are conditioned upon the formal adoption of the CPS as an Illinois rule. On January 5, 2007, the Illinois EPA and Midwest Generation jointly filed the CPS in the pending state rulemaking related to the Illinois SIP for the CAIR. Midwest Generation expects the CPS to become final in the spring of 2007 and believes that, upon adoption, the CPS will provide greater predictability of the timing and amount of emissions reductions which will be required of the Illinois Plants for these pollutants through 2018. No assurance can be given that all required regulatory approvals will be received, and if not received, Midwest Generation will remain subject to existing and future requirements as to emissions of these pollutants.

If the agreement is implemented as contemplated, Midwest Generation will be required to achieve specified emissions reductions through a combination of environmental retrofits or unit shutdowns. The agreement contemplates three phases with each phase relating to one of the pollutants involved. Capital expenditures will be required for each phase.

The first phase involves installing activated carbon injection technology in 2008 and 2009 for the removal of mercury, a technology which EME has been testing at some of its plants. Capital expenditures relating to these controls are currently estimated to be approximately $60 million.

The second phase requires the installation of additional controls by the end of 2011 to further reduce NO_x emissions from units to be determined by Midwest Generation in order to achieve an agreed-on fleetwide level of NO_x emissions per million Btu. Capital expenditures for these controls are currently estimated to be approximately $450 million.

Thereafter, during the third phase of the plan, the focus will be on the reduction of SO_2 emissions. Midwest Generation will be required either to place controls on several units at the Illinois Plants between 2012 and 2018 for this purpose or to remove them from service. Midwest Generation will consider many factors in making this choice including, among others, an assessment of the cost and performance of environmental technologies and equipment, the remaining estimated useful life of each affected unit and the market outlook for the prices of various commodities including electrical energy and capacity, coal and natural gas. In view of the many factors involved, Midwest Generation has not yet determined what actions it may take at each affected unit to provide for optimal compliance with the agreement during its third phase. At this time, however, additional capital expenditures during the third phase of the plan are estimated as being in the range of approximately $2.2 billion to $2.9 billion, depending on the number of units on which controls are placed versus the number which are removed from service. For the reasons described above, actual capital expenditures may vary substantially from the above estimates.

On May 30, 2006, the Illinois EPA submitted a proposed regulation to the Illinois Pollution Control Board to implement the Illinois SIP required for compliance with the CAIR. The Illinois Pollution Control Board held hearings on this SIP on October 10, 2006 and November 28, 2006. As noted previously, on January 5, 2007 the Illinois EPA and Midwest Generation filed the CPS in the pending Illinois rulemaking.

Pennsylvania—

The Pennsylvania Environmental Quality Board accepted the PADEP's proposed SIP to implement the CAIR on February 20, 2007. The SIP is very similar to the Federal CAIR with modest NOx set asides for generation from renewables and waste coal. At this time EME plans to comply with the proposal using existing pollution control equipment supplemented with the purchase of SO_2 credits for the first phase of the rule which is effective in 2010.

Mercury Regulation

The CAMR, published in the Federal Register on May 18, 2005, creates a market-based cap-and-trade program to reduce nationwide utility emissions of mercury in two distinct phases. In the first phase of the program, which will come into effect in 2010, the annual nationwide cap will be 38 tons. Emissions of mercury are to be reduced primarily by taking advantage of mercury reductions achieved by reducing SO_2 and NO_x emissions under the CAIR. In the second phase, which is to take effect in 2018, coal-fired power plants will be subject to a lower annual cap, which will reduce emissions nationwide to 15 tons. States may join the trading program by adopting the CAMR model trading rule in state regulations, or they may adopt regulations that mirror the necessary components of the model trading rule. States are not required to adopt a cap-and-trade program and may promulgate alternative regulations, such as command and control regulations, that are equivalent to or more stringent than the CAMR's suggested cap-and-trade program. Any program adopted by a state must be approved by the US EPA.

Contemporaneous with the adoption of the CAMR, the US EPA rescinded its previous finding that mercury emissions from coal-fired power plants had to be regulated as a hazardous air pollutant pursuant to Section 112 of the federal Clean Air Act, which would have imposed technology-based standards. Both the US EPA's rescission action and the CAMR are being challenged in the courts. Because EME cannot predict the outcome of these challenges, which could result in changes to the CAMR rules and timetables, the full impact of this regulation currently cannot be assessed.

Illinois—

The final state rule for the reduction of mercury emissions in Illinois was adopted and became effective on December 21, 2006. The rule requires a 90% reduction of mercury emissions from coal-fired power plants averaged across company-owned Illinois stations and a minimum reduction of 75% for individual generating sources by July 1, 2009. The rule requires each station to achieve a 90% reduction by January 1, 2014 and, because emissions are measured on a rolling 12-month average, stations must install equipment necessary to meet the January 1, 2014, 90% reduction by January 1, 2013. Buying or selling of emission allowances under the federal CAMR cap and trade program would be prohibited.

Midwest Generation's pending CPS, if adopted, will supersede this rule for the Illinois Plants. The CPS requires installation of activated carbon injection technology for the removal of mercury on all Midwest Generation units by July 2009 (except for three units to be shut down by the end of 2010), prohibits participation in the federal cap-and-trade program, and requires a 90% removal of mercury by unit by the end of 2015. While its CPS is pending, Midwest Generation has filed an appeal of the state's mercury rule that would require a 90% fleetwide reduction in mercury emissions by July 2009.

Pennsylvania—

On February 17, 2007, the PADEP published in the Pennsylvania Bulletin regulations that would require coal-fired power plants to reduce mercury emissions by 80% by 2010 and 90% by 2015. The rule does not allow the use of emissions trading to achieve compliance. The rule became final upon publication.

At this time EME expects the Homer City facilities to achieve compliance by the 2010 deadline with mercury removal achieved by an existing flue gas desulfurization system on one generating unit and by sorbent injection on the other two units. EME has deferred making commitments for the installation of further environmental controls at the Homer City facilities at this time, but continues to study available environmental control technologies and estimated costs to reduce SO_2 and mercury and to monitor developments related to mercury and other environmental regulations.

Ambient Air Quality Standards

The US EPA designated non-attainment areas for its 8-hour ozone standard on April 30, 2004, and for its fine particulate matter standard on January 5, 2005. Almost all of EME's facilities are located in counties that have been identified as being in non-attainment with both standards. States are required to revise their SIPs for the ozone and particulate matter standards within three years of the effective date of the respective non-attainment designations. The revised SIPs are likely to require additional emission reductions from facilities that are significant emitters of ozone precursors and particulates. Any additional obligations on EME's facilities to further reduce their emissions of SO_2, NO_x and fine particulates to address local non-attainment with the 8-hour ozone and fine particulate matter standards will not be known until the states revise their SIPs. Depending upon the final standards that are adopted, EME may incur substantial costs or experience other financial impacts resulting from required capital improvements or operational changes.

On September 22, 2006 the US EPA issued a final rule that implements the revisions to its fine particulate standard originally proposed on January 17, 2006. Under the new rule, the annual standard remains the same but the 24-hour fine particulate standard is significantly more stringent. The rule may require states to impose further emission reductions beyond those necessary to meet the existing standards. EME anticipates that any such further emissions reduction obligations would not be imposed under this standard until 2015 at the earliest, and intends to consider such rules as part of its overall plan for environmental compliance.

Illinois—

Beginning with the 2003 ozone season (May 1 through September 30), EME has been required to comply with an average NO_x emission rate of 0.25 lb NO_x/MMBtu of heat input. This limitation is commonly referred to as the East St. Louis State Implementation Plan. This regulation is a State of Illinois requirement. Each of the Illinois Plants complied with this standard in 2004. Beginning with the 2004 ozone season, the Illinois Plants became subject to the federally mandated "NO_x SIP Call" regulation that provided ozone-season NO_x emission allowances to a 19-state region east of the Mississippi. This program provides for NO_x allowance trading similar to the SO_2 (acid rain) trading program already in effect.

During 2004, the Illinois Plants stayed within their NO_x allocations by augmenting their allocation with early reduction credits generated within the fleet. In 2005, the Illinois Plants used banked allowances, along with some purchased allowances, to stay within their NO_x allocations. In 2006, the Illinois Plants used purchased allowances to stay within their NO_x allocations. Midwest Generation plans to continue to purchase allowances as it implements the agreement it reached with the Illinois EPA.

The Illinois EPA has begun to develop SIPs to meet National Ambient Air Quality Standards for 8-hour ozone and fine particulates with the intent of bringing non-attainment areas, such as Chicago, into attainment. The SIPs are expected to deal with all emission sources, not just power generators, and to address emissions of NO_x, SO_2, and volatile organic compounds. These SIPs are to be submitted to the US EPA by June 15, 2007 for 8-hour ozone, and by April 5, 2008 for fine particulates.

Midwest Generation's agreement with the Illinois EPA and the pending CPS include emission controls that will contribute to ozone and fine particulate attainment. Midwest Generation expects, but cannot guarantee, that the reductions required under the agreement and the pending CPS will be sufficient for compliance with future ozone and particulate matter regulations. See "—Clean Air Act—Illinois" for further discussion.

Pennsylvania—

The Homer City facilities comply with current ozone requirements due to the selective catalytic reduction systems installed at each unit. Particulate requirements are met using a combination of scrubber reductions from Unit 3 and the purchase of SO_2 allowances. Pennsylvania has not yet proposed new regulations to implement the National Ambient Air Quality Standards for 8-hour ozone or for fine particulates. These SIPs are to be submitted to US EPA by June 15, 2007 and April 5, 2008, respectively. Although the final form of the SIPs is not yet known, at this time EME anticipates that current treatment will be sufficient to meet the SIP requirements for 8-hour ozone, and that the SIP for fine particulates will require the continued use of the existing scrubber supplemented by the purchase of SO_2 allowances.

Regional Haze—

The goal of the 1999 regional haze regulations is to restore visibility in mandatory federal Class I areas, such as national parks and wilderness areas, to natural background conditions in 60 years. Sources such as power plants that are reasonably anticipated to contribute to visibility impairment in Class I areas may be required to install BART or implement other control strategies to meet regional haze control requirements. States are required to revise their SIPs to demonstrate reasonable further progress towards meeting regional haze goals. Emission reductions achieved through other ongoing control programs may be sufficient to demonstrate reasonable progress toward the long-term goal, particularly for the first 10 to 15 year phase of the program. States must develop SIPs by December 2007. It is possible that sources subject to the CAIR will be able to satisfy their obligations under the regional haze regulations through compliance with the CAIR. However, until the SIPs are revised, EME cannot predict whether it will be required to install BART or implement other control strategies, and cannot identify the financial impacts of any additional control requirements.

The CPS, discussed above in "—Clean Air Act—Illinois," addresses emissions reductions at BART affected sources. In Pennsylvania, the PADEP considers the CAIR to meet the BART requirements, and the Homer City facilities are only required to consider reductions in emissions of suspended particulate matter (PM10), which at this time have not been developed by the state.

New Source Review Requirements

Since 1999, the US EPA has pursued a coordinated compliance and enforcement strategy to address Clean Air Act NSR compliance issues at the nation's coal-fired power plants. The NSR regulations impose certain requirements on facilities, such as electric generating stations, in the event that modifications are made to air emissions sources at a facility. The US EPA's strategy included both the filing of a number of suits against power plant owners, and the issuance of a number of administrative notices of violation to power plant owners alleging NSR violations. Neither EME nor any of its subsidiaries has been named as a defendant in these lawsuits and have not received any administrative Notices of Violation alleging NSR violations at any of their facilities.

On October 13, 2005, the US EPA proposed a change to the NSR program. The proposal put forth several options for a new emissions test based on the impact of a facility modification on a facility's maximum hourly emissions or its emissions per unit of energy produced. The existing NSR emissions test is based on the impact of a modification on a generating station's net annual emissions.

In October 2005, the US EPA announced a revised NSR strategy to take account of recent US EPA rulemakings, such as the CAIR and regional haze rules, affecting coal-fired power plants. Under the revised strategy, while the US EPA will continue to pursue filed cases and cases in active negotiation, it intends to shift its future enforcement focus from coal-fired power plants to other sectors where compliance assurance activities have the potential to produce significant environmental benefits.

Prior to EME's purchase of the Homer City facilities, the US EPA requested information under Section 114 of the Clean Air Act from the prior owners of the plant concerning physical changes at the plant. This request was part of the US EPA's industry-wide investigation of compliance by coal-fired plants with the Clean Air Act NSR requirements. On February 21, 2003, Midwest Generation received a request for information under Section 114 regarding past operations, maintenance and physical changes at the Illinois Plants from the US EPA. On July 28, 2003, Commonwealth Edison received a substantially similar request for information from the US EPA related to the same plants. In a request dated February 1, 2005, the US EPA submitted a request for additional information to Midwest Generation. Midwest Generation has provided responses to these requests. Other than these requests for information, no NSR enforcement-related proceedings have been initiated by the US EPA with respect to any of EME's facilities.

EME will continue to monitor developments with respect to the NSR program and NSR enforcement to assess what implications, if any, they will have on its facilities, its results of operations or financial position.

Water Quality Regulation

Clean Water Act—Cooling Water Intake Structures

On July 9, 2004, the US EPA published the final Phase II rule implementing Section 316(b) of the Clean Water Act establishing standards for cooling water intake structures at existing large power plants. The purpose of the regulation is to reduce substantially the number of aquatic organisms that are pinned against cooling water intake structures or drawn into cooling water systems. Pursuant to the regulation, a demonstration study must be conducted when applying for a new or renewed NPDES wastewater discharge permit. If one can demonstrate that the costs of meeting the presumptive standards set forth in the regulation are significantly greater than the costs that the US EPA assumed in its rule making or are significantly disproportionate to the expected environmental benefits, a site-specific analysis may be performed to establish alternative standards. Depending on the findings of the demonstration studies, cooling towers and/or other mechanical means of reducing impingement and entrainment of aquatic organisms may be required. EME has begun to collect impingement and entrainment data at its potentially affected Midwest Generation facilities in Illinois to begin the process of determining what corrective actions may need to be taken.

The Phase II cooling water intake structure rule was challenged in the courts, and the cases were consolidated and transferred to the United States Court of Appeals for the Second Circuit. On January 25, 2007, the Second Circuit granted the petitions challenging the rule and remanded the rule to the US EPA for further proceedings. Although the Phase II rule could have a material impact on EME's operations, EME cannot reasonably determine the financial impact on it at this time because it is still collecting the data required by the regulation and because the challenges mentioned above may affect the obligations imposed by the rule.

Illinois

The Illinois EPA is reviewing the water quality standards for the Des Plaines River adjacent to the Joliet Station and immediately downstream of the Will County Station to determine if the use classification should be upgraded. If the existing use classification is changed, the limits on the temperature of the discharges from the Joliet and Will County plants may be made more stringent. The Illinois EPA has also begun a review of the water quality standards for the Chicago River and Chicago Sanitary and Ship Canal which are adjacent to the Fisk and Crawford Stations. Proposed changes to the existing standards are still being developed. Accordingly, EME is not able to estimate the financial impact of potential changes to the water quality standards. However, the cost of additional cooling water treatment, if required, could be substantial.

Pennsylvania

The discharge from the treatment plant receiving the wastewater stream from EME's Unit 3 flue gas desulfurization system at the Homer City facilities has exceeded the stringent water-quality based limits for selenium in the station's NPDES permit. As a result, EME was notified in April 2002 by the PADEP that it was included in the Quarterly Noncompliance Report submitted to the US EPA. With PADEP's approval, EME has undertaken a pilot program utilizing biological treatment. EME prepared a draft of a consent order and agreement addressing the selenium issue and presented it to the PADEP for consideration in connection with the renewal of the station's NPDES permit. The PADEP has included civil penalties in consent agreements related to other facilities with selenium treatment issues, but the amount of civil penalties that may be assessed against EME cannot be estimated at this time.

Environmental Remediation

Under various federal, state and local environmental laws and regulations, a current or previous owner or operator of any facility, including an electric generating facility, may be required to investigate and remediate releases or threatened releases of hazardous or toxic substances or petroleum products located at that facility, and may be held liable to a governmental entity or to third parties for property damage, personal injury, natural resource damages, and investigation and remediation costs incurred by these parties in connection with these releases or threatened releases. In addition, persons who arrange for the disposal or treatment of hazardous or toxic substances at a disposal or treatment facility may be liable for the costs to remediate releases of hazardous substances from such facilities even where the disposal of such wastes was undertaken in compliance with applicable laws. Many of these laws, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980, commonly referred to as CERCLA, as amended by the Superfund Amendments and Reauthorization Act of 1986, impose liability without regard to whether the owner knew of or caused the presence of the hazardous substances, and courts have interpreted liability under these laws to be strict and joint and several.

With respect to EME's potential liabilities arising under CERCLA or similar laws for the investigation and remediation of contaminated property, EME accrues a liability to the extent the costs are probable and can be reasonably estimated. Midwest Generation has accrued approximately $3 million at December 31, 2006 for estimated environmental investigation and remediation costs for the Illinois Plants. This estimate is based upon the number of sites, the scope of work and the estimated costs for environmental activity where such expenditures could be reasonably estimated. Future estimated costs may vary based on changes in regulations or requirements of federal, state, or local governmental agencies, changes in technology, and actual costs of disposal. In addition, future remediation costs will be affected by the nature and extent of contamination discovered at the sites that requires remediation. Given the prior history of the operations at its facilities, EME cannot be certain that the existence or extent of all contamination at its sites has been fully identified. However, based on available information, management believes that future costs in excess of the amounts disclosed on all known and quantifiable environmental contingencies will not be material to EME's financial position.

Federal, state and local laws, regulations and ordinances also govern the removal, encapsulation or disturbance of asbestos-containing materials when these materials are in poor condition or in the event of construction, remodeling, renovation or demolition of a building. Those laws and regulations may impose liability for release of asbestos-containing materials and may provide for the ability of third parties to seek recovery from owners or operators of these properties for personal injury associated with asbestos-containing materials. In connection with the ownership and operation of its facilities, EME may be liable for these costs. EME has agreed to indemnify the sellers of the Illinois Plants and the Homer City facilities with respect to specified environmental liabilities. See "—Contractual Obligations, Commitments and Contingencies—Commercial Commitments—Guarantees and Indemnities" for a discussion of these indemnities.

Climate Change

To date, the United States has chosen to pursue a voluntary greenhouse gas emissions reduction program to meet its obligations as a signatory to the United Nations Framework Convention on Climate Change. Currently a number of bills are proposed or under discussion in Congress to mandate reductions of greenhouse gas emissions. At this point, EME is unable to determine whether any of these proposals will be enacted into law or to estimate their potential effect on EME.

There have been petitions from states and other parties to compel the US EPA to regulate greenhouse gases under the CAIR. Also, in 2004, several states and environmental organizations brought a complaint in federal court in New York, alleging that several electric utility corporations are jointly and severally liable under a theory of public nuisance for damages caused by the alleged contribution to global warming resulting from carbon dioxide emissions from coal-fired power plants owned and operated by these companies or their subsidiaries. Neither EME nor its subsidiaries were named as defendants in the complaint. The case was dismissed and is currently on appeal with the United States Court of Appeals for the Second Circuit.

In April 2006, private citizens brought a complaint in federal court in Mississippi against numerous defendants, including several electric utilities, arguing that emissions from the defendants' facilities contributed to climate change and seeking monetary damages related to the 2005 hurricane season. On December 19, 2006, the plaintiffs sought permission from the court to file an amended complaint naming approximately one hundred new defendants, including EME and three of its subsidiaries. The court has not yet ruled on the plaintiffs' motion.

On December 20, 2005, seven northeastern states entered into a Memorandum of Understanding to create a regional initiative to establish a cap and trade greenhouse gas program for electric generators, referred to as the Regional Greenhouse Gas Initiative (RGGI). In August 2006, the participating states issued a model rule to be used as a basis for individual state legislative and regulatory action to implement the program. Illinois and Pennsylvania are not signatories to the RGGI, although Pennsylvania has participated as an observer of the process. Recent reports indicate that Pennsylvania is planning to announce a climate change policy that may include joining the RGGI. If Pennsylvania were to join the RGGI, this could have a material impact on EME's Homer City facilities.

In September 2006, California's Governor Schwarzenegger signed two bills into law regarding greenhouse gas emissions. The first, known as AB 32 or the California Global Warming Solutions Act of 2006, establishes a comprehensive program of regulatory and market mechanisms to achieve reductions of greenhouse gases. AB 32 requires the California Air Resources Board to develop regulations and market mechanisms targeted to reduce California's greenhouse gas emissions to 1990 levels by 2020. California Air Resources Board's mandatory program will take effect commencing 2012 and will implement incremental reductions so that greenhouse gas emissions will be reduced to 1990 levels by 2020. The second bill, known as SB 1368, requires the California Public Utilities Commission and the California Energy Commission to adopt greenhouse gas emissions performance standards for investor owned and publicly owned utilities, respectively, for long-term procurement of electricity. The standards must equal the performance of a combined-cycle gas turbine generator. The California Public Utilities Commission adopted such a standard on January 25, 2007 (which limits emissions to 1,100 pounds of carbon dioxide per MWh). The California Energy Commission must take similar action by June 30, 2007. In addition, the California Public Utilities Commission is addressing climate change related issues in various regulatory proceedings. At this time, EME believes that all of its facilities in California meet the greenhouse gas emissions performance standard contemplated by SB 1368, but EME will continue to monitor both regulations, as they are developed, for potential impact on its existing facilities and its projects under development.

The ultimate outcome of the climate change debate could have a significant economic effect on EME. Any legal obligation that would require EME to reduce substantially its emissions of carbon dioxide or would impose additional costs or charges for the emission of carbon dioxide could have a materially adverse effect on EME.

MARKET RISK EXPOSURES

Introduction

EME's primary market risk exposures are associated with the sale of electricity and capacity from and the procurement of fuel for its merchant power plants. These market risks arise from fluctuations in electricity, capacity and fuel prices, emission allowances, and transmission rights. Additionally, EME's financial results can be affected by fluctuations in interest rates. EME manages these risks in part by using derivative financial instruments in accordance with established policies and procedures.

This section discusses these market risk exposures under the following headings:

Commodity Price Risk

Overview

EME's revenues and results of operations of its merchant power plants will depend upon prevailing market prices for capacity, energy, ancillary services, emission allowances or credits, coal, natural gas and fuel oil, and associated transportation costs in the market areas where EME's merchant plants are located. Among the factors that influence the price of energy, capacity and ancillary services in these markets are:

- prevailing market prices for coal, natural gas and fuel oil, and associated transportation;
- the extent of additional supplies of capacity, energy and ancillary services from current competitors or new market entrants, including the development of new generation facilities and/ or technologies that may be able to produce electricity at a lower cost than EME's generating facilities and/or increased access by competitors to EME's markets as a result of transmission upgrades;
- transmission congestion in and to each market area and the resulting differences in prices between delivery points;
- the market structure rules established for each market area and regulatory developments affecting the market areas, including any price limitations and other mechanisms adopted to address volatility or illiquidity in these markets or the physical stability of the system;
- the cost and availability of emission credits or allowances;
- the availability, reliability and operation of competing power generation facilities, including nuclear generating plants, where applicable, and the extended operation of such facilities beyond their presently expected dates of decommissioning;
- weather conditions prevailing in surrounding areas from time to time; and

- changes in the demand for electricity or in patterns of electricity usage as a result of factors such as regional economic conditions and the implementation of conservation programs. A discussion of commodity price risk for the Illinois Plants and the Homer City facilities is set forth below.

Introduction

EME's merchant operations expose it to commodity price risk, which represents the potential loss that can be caused by a change in the market value of a particular commodity. Commodity price risks are actively monitored by a risk management committee to ensure compliance with EME's risk management policies. Policies are in place which define risk management processes, and procedures exist which allow for monitoring of all commitments and positions with regular reviews by EME's risk management committee. Despite this, there can be no assurance that all risks have been accurately identified, measured and/or mitigated.

In addition to prevailing market prices, EME's ability to derive profits from the sale of electricity will be affected by the cost of production, including costs incurred to comply with environmental regulations. The costs of production of the units vary and, accordingly, depending on market conditions, the amount of generation that will be sold from the units is expected to vary.

EME uses "value at risk" to identify, measure, monitor and control its overall market risk exposure in respect of its Illinois Plants, its Homer City facilities, and its trading positions. The use of value at risk allows management to aggregate overall commodity risk, compare risk on a consistent basis and identify the risk factors. Value at risk measures the possible loss over a given time interval, under normal market conditions, at a given confidence level. Given the inherent limitations of value at risk and relying on a single risk measurement tool, EME supplements this approach with the use of stress testing and worst-case scenario analysis for key risk factors, as well as stop-loss limits and counterparty credit exposure limits.

Hedging Strategy

To reduce its exposure to market risk, EME hedges a portion of its merchant portfolio risk through EMMT, an EME subsidiary engaged in the power marketing and trading business. To the extent that EME does not hedge its merchant portfolio, the unhedged portion will be subject to the risks and benefits of spot market price movements. Hedge transactions are primarily implemented through:

- the use of contracts cleared on the Intercontinental Trading Exchange and the New York Mercantile Exchange,
- forward sales transactions entered into on a bilateral basis with third parties, including electric utilities and power marketing companies, and
- full requirements services contracts or load requirements services contracts for the procurement of power for electric utilities' customers, with such services including the delivery of a bundled product including, but not limited to, energy, transmission, capacity, and ancillary services, generally for a fixed unit price.

The extent to which EME enters into contracts to hedge its market price risk depends on several factors. First, EME evaluates over-the-counter market prices to determine whether sales at forward market prices are sufficiently attractive compared to assuming the risk associated with fluctuating spot market sales. Second, EME's ability to enter into hedging transactions depends upon its and Midwest Generation's credit capacity and upon the forward sales markets having sufficient liquidity to enable EME to identify appropriate counterparties for hedging transactions.

In the case of hedging transactions related to the generation and capacity of the Illinois Plants, Midwest Generation is permitted to use its working capital facility and cash on hand to provide credit support for these hedging transactions entered into by EMMT under an energy services agreement between Midwest Generation and EMMT. Utilization of this credit facility in support of hedging transactions provides additional liquidity support for implementation of EME's contracting strategy for the Illinois Plants. In the case of hedging transactions related to the generation and capacity of the Homer City facilities, credit support is provided by EME pursuant to intercompany arrangements between it and EMMT. See "—Credit Risk" below.

Recent Hedging Developments

In 2006, EMMT entered into agreements with third parties to hedge the price risk for power from the Illinois Plants for 2007, 2008 and 2009 (using the Northern Illinois Hub as a reference point). Under the terms of these agreements, EME has guaranteed the obligations of EMMT, but neither EME nor EMMT is required to post margin, provide liens on property or provide other collateral to support the obligations under the agreements.

EMMT participated in an Illinois auction in September 2006, which resulted in its entry into two load requirements contracts with Commonwealth Edison with periods of seventeen months and twenty-nine months, beginning January 1, 2007. Under load requirements services contracts, the amount of power sold is a portion of the retail load of the purchasing utility and can vary significantly with variations in that retail load. Retail load depends upon a number of factors, including the time of day, the time of the year and the utility's number of new and continuing customers.

Energy Price Risk Affecting Sales from the Illinois Plants

All the energy and capacity from the Illinois Plants is sold under terms, including price and quantity, arranged by EMMT with customers through a combination of bilateral agreements (resulting from negotiations or from auctions), forward energy sales and spot market sales. As discussed further below, power generated at the Illinois Plants is generally sold into the PJM market.

Midwest Generation sells its power into PJM at spot prices based upon locational marginal pricing. Hedging transactions related to the generation of the Illinois Plants are generally entered into at the Northern Illinois Hub in PJM, and may also be entered into at other trading hubs, including the AEP/Dayton Hub in PJM and the Cinergy Hub in the MISO. These trading hubs have been the most liquid locations for hedging purposes. However, hedging transactions which settle at points other than the Northern Illinois Hub are subject to the possibility of basis risk. See "—Basis Risk" below for further discussion.

PJM has a short-term market, which establishes an hourly clearing price. The Illinois Plants are situated in the PJM control area and are physically connected to high-voltage transmission lines serving this market.

The following table depicts the average historical market prices for energy per megawatt-hour during 2006, 2005 and 2004.

	2006(1)	2005(1)	2004
January	$ 42.27	$ 38.36	$ 27.88(2)
February	42.66	34.92	29.98(2)
March	42.50	45.75	30.66(2)
April	43.16	38.98	27.88(2)
May	39.96	33.60	34.05(1)
June	34.80	42.45	28.58(1)
July	51.82	50.87	30.92(1)
August	54.76	60.09	26.31(1)
September	31.87	53.30	27.98(1)
October	37.80	49.39	30.93(1)
November	41.90	44.03	29.15(1)
December	33.57	64.99	29.90(1)
Yearly Average	$ 41.42	$ 46.39	$ 29.52

(1) Represents average historical market prices for energy as quoted for sales into the Northern Illinois Hub. Energy prices were calculated at the Northern Illinois Hub delivery point using hourly real-time prices as published by PJM.

(2) Represents average historical market prices for energy "Into ComEd." Energy prices were determined by obtaining broker quotes and other public price sources for "Into ComEd" delivery points.

Forward market prices at the Northern Illinois Hub fluctuate as a result of a number of factors, including natural gas prices, transmission congestion, changes in market rules, electricity demand (which in turn is affected by weather, economic growth, and other factors), plant outages in the region, and the amount of existing and planned power plant capacity. The actual spot prices for electricity delivered by the Illinois Plants into these markets may vary materially from the forward market prices set forth in the table below.

The following table sets forth the forward month-end market prices for energy per megawatt-hour for the calendar year 2007 and calendar year 2008 "strips," which are defined as energy purchases for the entire calendar year, as quoted for sales into the Northern Illinois Hub during 2006:

	24-Hour Northern Illinois Hub Forward Energy Prices(1)	
	2007	2008
January 31, 2006	$ 51.25	$ 49.01
February 28, 2006	45.61	44.74
March 31, 2006	48.61	48.58
April 30, 2006	51.38	49.88
May 31, 2006	44.92	44.89
June 30, 2006	45.49	45.10
July 31, 2006	48.93	47.67
August 31, 2006	48.68	48.40
September 30, 2006	44.31	45.09
October 31, 2006	44.44	45.63
November 30, 2006	46.35	46.66
December 31, 2006	41.00	45.14

(1) Energy prices were determined by obtaining broker quotes and information from other public sources relating to the Northern Illinois Hub delivery point.

The following table summarizes Midwest Generation's hedge position at December 31, 2006:

	2007	2008	2009
Energy Only Contracts(1)			
Megawatt-hours	16,323,600	10,854,400	2,048,000
Average price/MWh(2)	$48.39	$61.33	$60.00
Load Requirements Services Contracts			
Estimated megawatt-hours(3)	8,522,380	6,209,315	1,805,456
Average price/MWh(4)	$64.13	$64.01	$63.65
Total estimated megawatt-hours	24,845,980	17,063,715	3,853,456

(1) Primarily at Northern Illinois Hub.

(2) The energy only contracts include forward contracts for the sale of power and futures contracts during different periods of the year and the day. Market prices tend to be higher during on-peak periods and during summer months, although there is significant variability of power prices during different periods of time. Accordingly, the above hedge position at December 31, 2006 is not directly comparable to the 24-hour Northern Illinois Hub prices set forth above.

(3) Under a load requirements services contract, the amount of power sold is a portion of the retail load of the purchasing utility and thus can vary significantly with variations in that retail load. Retail load depends upon a number of factors, including the time of day, the time of the year and the utility's number of new and continuing customers. Estimated megawatt-hours have been forecast based on historical patterns and on assumptions regarding the factors that may affect retail loads in the future. The actual load will vary from that used for the above estimate, and the amount of variation may be material.

(4) The average price per megawatt-hour under a load requirements services contract (which is subject to a seasonal price adjustment) represents the sale of a bundled product that includes, but is not limited to, energy, capacity and ancillary services. Furthermore, as a supplier of a portion of a utility's load, Midwest Generation will incur charges from PJM as a load serving entity. For these reasons, the average price per megawatt-hour under a load requirements services contract is not comparable to the sale of power under an energy only contract. The average price per megawatt-hour under a load requirements services contract represents the sale of the bundled product based on an estimated customer load profile.

The load requirements services contracts set forth in the table above are with Commonwealth Edison. Commonwealth Edison has stated that it would face possible bankruptcy if an electric rate freeze, which expired January 1, 2007, was re-introduced through legislation. On January 7, 2007, the Illinois House of Representatives voted to extend the rate freeze by three years, but the bill was not acted on by the State Senate before the Legislature adjourned its 2005-2006 session. It is possible that the issue will be revisited in the new 2007-2008 session, which convened on January 10, 2007. In addition, the Illinois Attorney General and other parties have appeals pending before the Illinois Supreme Court pertaining to the Illinois Commerce Commission orders which authorized Commonwealth Edison and Ameren Corporation to procure power through a reverse auction process. EME is unable to predict the outcome of the appeals or whether legislation or other policy changes affecting utility rates or procurement practices will be enacted, and, if so, what effect these developments may have on Commonwealth Edison's performance under the load requirement services contracts.

Energy Price Risk Affecting Sales from the Homer City Facilities

All the energy and capacity from the Homer City facilities is sold under terms, including price and quantity, arranged by EMMT with customers through a combination of bilateral agreements (resulting from negotiations or from auctions), forward energy sales and spot market sales. Electric power generated at the Homer City facilities is generally sold into the PJM market. PJM has a short-term market, which establishes an hourly clearing price. The Homer City facilities are situated in the PJM control area and are physically connected to high-voltage transmission lines serving both the PJM and NYISO markets.

The following table depicts the average historical market prices for energy per megawatt-hour at the Homer City busbar and in PJM West Hub (EME Homer City's primary trading hub) during the past three years:

	Historical Energy Prices(1) 24-Hour PJM					
	Homer City Busbar			PJM West Hub		
	2006	2005	2004	2006	2005	2004
January	$ 48.67	$ 45.82	$ 51.12	$ 54.57	$ 49.53	$ 55.01
February	49.54	39.40	47.19	56.39	42.05	44.22
March	53.26	47.42	39.54	58.30	49.97	39.21
April	48.50	44.27	43.01	49.92	44.55	42.82
May	44.71	43.67	44.68	48.55	43.64	48.04
June	38.78	46.63	36.72	45.78	53.72	38.05
July	53.68	54.63	40.09	63.47	66.34	43.64
August	58.60	66.39	34.76	76.57	82.83	38.59
September	33.26	66.67	40.62	34.40	76.82	41.96
October	37.42	67.93	37.37	39.65	77.56	37.78
November	40.13	59.78	35.79	44.83	62.01	36.91
December	35.29	75.03	38.59	40.53	81.97	41.83
Yearly Average	$ 45.15	$ 54.80	$ 40.79	$ 51.08	$ 60.92	$ 42.34

(1) Energy prices were calculated at the Homer City busbar (delivery point) and PJM West Hub using historical hourly real-time prices provided on the PJM web-site.

Forward market prices at the PJM West Hub fluctuate as a result of a number of factors, including natural gas prices, transmission congestion, changes in market rules, electricity demand (which in turn is affected by weather, economic growth and other factors), plant outages in the region, and the amount of existing and planned power plant capacity. The actual spot prices for electricity delivered by the Homer City facilities into these markets may vary materially from the forward market prices set forth in the table below.

The following table sets forth the forward month-end market prices for energy per megawatt-hour for the calendar 2007 and 2008 "strips," which are defined as energy purchases for the entire calendar year, as quoted for sales into the PJM West Hub during 2006:

	24-Hour PJM West Hub Forward Energy Prices(1)	
	2007	**2008**
January 31, 2006	$ 70.89	$ 67.69
February 28, 2006	62.16	60.09
March 31, 2006	66.79	64.37
April 30, 2006	70.11	68.07
May 31, 2006	63.22	61.33
June 30, 2006	63.80	62.58
July 31, 2006	67.66	64.26
August 31, 2006	65.23	63.17
September 30, 2006	57.61	58.25
October 31, 2006	57.97	59.31
November 30, 2006	61.26	61.83
December 31, 2006	52.13	59.13

(1) Energy prices were determined by obtaining broker quotes and information from other public sources relating to the PJM West Hub delivery point. Forward prices at PJM West Hub are generally higher than the prices at the Homer City busbar.

The following table summarizes Homer City's hedge position at December 31, 2006:

	2007	**2008**	**2009**
Megawatt-hours	7,590,000	7,232,000	2,048,000
Average price/MWh(1)	$64.35	$60.85	$71.05

(1) The above hedge positions include forward contracts for the sale of power during different periods of the year and the day. Market prices tend to be higher during on-peak periods during summer months, although there is significant variability of power prices during different periods of time. Accordingly, the above hedge position at December 31, 2006 is not directly comparable to the 24-hour PJM West Hub prices set forth above.

The average price/MWh for Homer City's hedge position is based on PJM West Hub. Energy prices at the Homer City busbar have been lower than energy prices at the PJM West Hub. See "—Basis Risk" below for a discussion of the difference.

Basis Risk

Sales made from the Illinois Plants and the Homer City facilities in the real-time or day-ahead market receive the actual spot prices or day-ahead prices, as the case may be, at the busbars (delivery points) of the individual plants. In order to mitigate price risk from changes in spot prices at the individual plant busbars, EME may enter into cash settled futures contracts as well as forward contracts with counterparties for energy to be delivered in future periods. Currently, a liquid market for entering into these contracts at the individual plant busbars does not exist. A liquid market does exist for a settlement point at the PJM West Hub in the case of the Homer City facilities and for a settlement point at the Northern Illinois Hub in the case of the Illinois Plants. EME's hedging activities use these settlement points (and, to a lesser extent, other similar trading hubs) to enter into hedging contracts. EME's revenues with respect to such forward contracts include:

- sales of actual generation in the amounts covered by the forward contracts with reference to PJM spot prices at the busbar of the plant involved, plus,
- sales to third parties at the price under such hedging contracts at designated settlement points (generally the PJM West Hub for the Homer City facilities and the Northern Illinois Hub for the Illinois Plants) less the cost of power at spot prices at the same designated settlement points.

Under PJM's market design, locational marginal pricing, which establishes market prices at specific locations throughout PJM by considering factors including generator bids, load requirements, transmission congestion and losses, can cause the price of a specific delivery point to be higher or lower relative to other locations depending on how the point is affected by transmission constraints. To the extent that, on the settlement date of a hedge contract, spot prices at the relevant busbar are lower than spot prices at the settlement point, the proceeds actually realized from the related hedge contract are effectively reduced by the difference. This is referred to as "basis risk." During 2006, transmission congestion in PJM has resulted in prices at the Homer City busbar being lower than those at the PJM West Hub by an average of 12%, compared to 10% during 2005 and 4% during 2004. The monthly average difference during 2006 ranged from 3% to 23%. In contrast to the Homer City facilities, during the past 12 months, the prices at the Northern Illinois Hub were substantially the same as those at the individual busbars of the Illinois Plants.

By entering into cash settled futures contracts and forward contracts using the PJM West Hub and the Northern Illinois Hub (or other similar trading hubs) as settlement points, EME is exposed to basis risk as described above. In order to mitigate basis risk, EME has purchased 3.5 terawatt-hours of financial transmission rights and basis swaps in PJM for Homer City during the period January 1, 2007 through May 31, 2007, and may continue to purchase financial transmission rights and basis swaps in the future. A financial transmission right is a financial instrument that entitles the holder to receive the difference of actual spot prices for two delivery points in exchange for a fixed amount. Accordingly, EME's hedging activities include using financial transmission rights alone or in combination with forward contracts and basis swap contracts to manage basis risk.

Coal Price Risk

The Illinois Plants and the Homer City facilities purchase coal primarily obtained from the Southern PRB of Wyoming and from mines located near the facilities in Pennsylvania, respectively. Coal purchases are made under a variety of supply agreements extending through 2010. The following table summarizes the amount of coal under contract at December 31, 2006 for the next four years.

	Amount of Coal Under Contract in Millions of Tons(1)			
	2007	2008	2009	2010
Illinois Plants	17.2	5.8	5.8	5.8
Homer City facilities	5.2	2.1	0.8	—

(1) The amount of coal under contract in tons is calculated based on contracted tons and applying an 8,800 Btu equivalent for the Illinois Plants and 13,000 Btu equivalent for the Homer City facilities.

In February 2007, Midwest Generation contracted for the purchase of additional coal in the amount of 9 million tons for 2008, 6 million tons for 2009 and 6 million tons for 2010.

EME is subject to price risk for purchases of coal that are not under contract. Prices of NAPP coal, which are related to the price of coal purchased for the Homer City facilities, decreased slightly in 2006 from 2005 year-end prices and increased considerably during 2005 and 2004. The price of NAPP coal (with 13,000 Btu per pound heat content and <3.0 pounds of SO_2 per MMBtu sulfur content) fluctuated between $37.50 per ton and $45.00 per ton during 2006, with a price of $43.00 per ton at December 15, 2006, as reported by the Energy Information Administration. The 2006 decrease in the NAPP coal price was largely due to the combined effects of mild weather, easing natural gas prices and improving eastern stockpiles. In 2005, the price of NAPP coal fluctuated between $44.00 per ton and $57.00 per ton, with a price of $45.00 per ton at December 30, 2005, as reported by the Energy Information Administration. In 2004, the price of NAPP coal increased to more than $60.00 per ton from below $40.00 per ton in January 2004. The 2005 overall increase in the NAPP coal price was largely attributed to greater demand from domestic power producers and increased international shipments of coal to Asia. Prices of PRB coal (with 8,800 Btu per pound heat content and 0.8 pounds of SO_2 per MMBtu sulfur content), which is purchased for the Illinois Plants decreased during 2006 from 2005 year-end prices due to easing natural gas prices, fuel switching, lower prices for SO_2 allowances and improved inventory. Prices of PRB coal significantly increased in 2005 due to the curtailment of coal shipments during 2005 due to increased PRB coal demand from other regions (east), rail constraints, higher oil and natural gas prices and higher prices for SO_2 allowances. The price of PRB coal decreased from $20.66 per ton in January 2006 to $9.90 per ton at December 15, 2006, as reported by the Energy Information Administration, which compares to 2005 prices that ranged from $6.20 per ton to $18.48 per ton and 2004 prices which were generally below $7 per ton.

Based on EME's anticipated coal requirements in 2007 in excess of the amount under contract, EME expects that a 10% change in the price of coal at December 31, 2006 would increase or decrease pre-tax income in 2007 by approximately $2 million.

Emission Allowances Price Risk

The federal Acid Rain Program requires electric generating stations to hold SO_2 allowances, and Illinois and Pennsylvania regulations implemented the federal NO_x SIP Call requirement. Under these programs, EME purchases (or sells) emission allowances based on the amounts required for actual generation in excess of (or less than) the amounts allocated under these programs. As part of the acquisition of the Illinois Plants and the Homer City facilities, EME obtained the rights to the emission allowances that have been or are allocated to these plants.

The price of emission allowances, particularly SO_2 allowances issued through the federal Acid Rain Program, decreased in 2006 from 2005 year-end prices and increased substantially during 2005 and 2004. The average price of purchased SO_2 allowances was $664 per ton during 2006, $1,219 per ton during 2005 and $435 per ton during 2004. The decrease in the price of SO_2 allowances during 2006 from 2005 year-end prices has been attributed to a decline in natural gas prices and fuel switching from oil to gas. The 2005 increase in the price of SO_2 allowances had been attributed to reduced numbers of both allowance sellers and prior-year allowances. The price of SO_2 allowances, determined by obtaining broker quotes and information from other public sources, was $476 per ton as of January 31, 2007.

Based on EME's anticipated SO_2 emission allowances requirements in 2007, EME expects that a 10% change in the price of SO_2 emission allowances at December 31, 2006 would increase or decrease pre-tax income in 2007 by approximately $2 million. See "Liquidity and Capital Resources—Environmental Matters and Regulations" for a discussion of environmental regulations related to emissions.

Accounting for Energy Contracts

EME uses a number of energy contracts to manage exposure from changes in the price of electricity, including forward sales and purchases of physical power and forward price swaps which settle only on a financial basis (including futures contracts). EME follows SFAS No. 133, and under this Standard these energy contracts are generally defined as derivative financial instruments. Importantly, SFAS No. 133 requires changes in the fair value of each derivative financial instrument to be recognized in earnings at the end of each accounting period unless the instrument qualifies for hedge accounting under the terms of SFAS No. 133. For derivatives that do qualify for cash flow hedge accounting, changes in their fair value are recognized in other comprehensive income until the hedged item settles and is recognized in earnings. However, the ineffective portion of a derivative that qualifies for cash flow hedge accounting is recognized currently in earnings. For further discussion of derivative financial instruments, see "Management's Overview; Critical Accounting Estimates—Critical Accounting Estimates—Derivative Financial Instruments and Hedging Activities."

SFAS No. 133 affects the timing of income recognition, but has no effect on cash flow. To the extent that income varies under SFAS No. 133 from accrual accounting (i.e., revenue recognition based on settlement of transactions), EME records unrealized gains or losses. Unrealized SFAS No. 133 gains or losses result from:

- energy contracts that do not qualify for hedge accounting under SFAS No. 133 (which are sometimes referred to as economic hedges). Unrealized gains and losses include:
    - the change in fair value (sometimes called mark-to-market) of economic hedges that relate to subsequent periods, and
    - offsetting amounts to the realized gains and losses in the period non-qualifying hedges are settled.
- the ineffective portion of qualifying hedges which generally relate to changes in the expected basis between the sale point and the hedge point. Unrealized gains or losses include:
    - the current period ineffectiveness on the hedge program for subsequent periods. This occurs because the ineffective gains or losses are recorded in the current period, whereby the energy

revenues related to generation being hedged will be recorded in the subsequent period along with the effective portion of the related hedge transaction, and

- offsetting amounts to the realized ineffective gains and losses in the period cash flow hedges are settled.

EME classifies unrealized gains and losses from energy contracts as part of operating revenues. The results of derivative activities are recorded as part of cash flows from operating activities in the consolidated statements of cash flows. The following table summarizes unrealized gains (losses) from non-trading activities for the three-year period ended December 31, 2006:

	Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Non-qualifying hedges			
Illinois Plants	$ 28	$ (17)	$ (4)
Homer City	2	(1)	1
Ineffective portion of cash flow hedges			
Illinois Plants	2	(2)	—
Homer City	33	(40)	(14)
Total unrealized gains (losses)	$ 65	$ (60)	$ (17)

Fair Value of Financial Instruments

Non-Trading Derivative Financial Instruments

The following table summarizes the fair values for outstanding derivative financial instruments used in EME's continuing operations for purposes other than trading, by risk category (in millions):

	December 31, 2006	December 31, 2005
Commodity price:		
Electricity	$ 184	$ (434)

In assessing the fair value of EME's non-trading derivative financial instruments, EME uses a variety of methods and assumptions based on the market conditions and associated risks existing at each balance sheet date. The fair value of commodity price contracts takes into account quoted market prices, time value of money, volatility of the underlying commodities and other factors. The increase in the fair value of electricity contracts in 2006 as compared to 2005 is attributable to a decline in the average market prices for power as compared to contracted prices at December 31, 2006, which is the valuation date. A 10% change in the market price at December 31, 2006 would increase or decrease the fair value of outstanding derivative commodity price contracts by approximately $347 million. The following table summarizes the maturities and the related fair value, based on actively traded prices, of EME's commodity derivative assets and liabilities as of December 31, 2006 (in millions):

	Total Fair Value	Maturity <1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity >5 years
Prices actively quoted	$ 184	$ 161	$ 23	$ —	$ —

Energy Trading Derivative Financial Instruments

The fair value of the commodity financial instruments related to energy trading activities as of December 31, 2006 and 2005, are set forth below (in millions):

	December 31, 2006		December 31, 2005	
	Assets	**Liabilities**	**Assets**	**Liabilities**
Electricity	$ 313	$ 207	$ 127	$ 27
Other	5	—	1	—
Total	$ 318	$ 207	$ 128	$ 27

The change in the fair value of trading contracts for the year ended December 31, 2006 was as follows (in millions):

Fair value of trading contracts at January 1, 2006	$ 101
Net gains from energy trading activities	137
Amount realized from energy trading activities	(131)
Other changes in fair value	4
Fair value of trading contracts at December 31, 2006	$ 111

A 10% change in the market price at December 31, 2006 would increase or decrease the fair value of trading contracts by approximately $2 million.

Quoted market prices are used to determine the fair value of the financial instruments related to energy trading activities, except for the power sales agreement with an unaffiliated electric utility that EME's subsidiary purchased and restructured and a long-term power supply agreement with another unaffiliated party. EME's subsidiary recorded these agreements at fair value based upon a discounting of future electricity prices derived from a proprietary model using a discount rate equal to the cost of borrowing the non-recourse debt incurred to finance the purchase of the power supply agreement. The following table summarizes the maturities, the valuation method and the related fair value of energy trading assets and liabilities (as of December 31, 2006) (in millions):

	Total Fair Value	**Maturity <1 year**	**Maturity 1 to 3 years**	**Maturity 4 to 5 years**	**Maturity >5 years**
Prices actively quoted	$ 26	$ 26	$ —	$ —	$ —
Prices provided by other external sources	(1)	(1)	—	—	—
Prices based on models and other valuation methods	86	4	13	18	51
Total	$ 111	$ 29	$ 13	$ 18	$ 51

Credit Risk

In conducting EME's hedging and trading activities, EME contracts with a number of utilities, energy companies, financial institutions, and other companies, collectively referred to as counterparties. In the event a counterparty were to default on its trade obligation, EME would be exposed to the risk of possible loss associated with re-contracting the product at a price different from the original contracted price if the non-performing counterparty were unable to pay the resulting liquidated damages owed to EME. Further, EME would be exposed to the risk of non-payment of accounts receivable accrued for products delivered prior to the time a counterparty defaulted.

To manage credit risk, EME looks at the risk of a potential default by counterparties. Credit risk is measured by the loss that would be incurred if counterparties failed to perform pursuant to the terms of their contractual obligations. EME measures, monitors and mitigates credit risk to the extent possible. To mitigate credit risk from counterparties, master netting agreements are used whenever possible and counterparties may be required to pledge collateral when deemed necessary. EME also takes other appropriate steps to limit or lower credit exposure. Processes have also been established to determine and monitor the creditworthiness of counterparties. EME manages the credit risk on the portfolio based on credit ratings using published ratings of counterparties and other publicly disclosed information, such as financial statements, regulatory filings, and press releases, to guide it in the process of setting credit levels, risk limits and contractual arrangements, including master netting agreements. A risk management committee regularly reviews the credit quality of EME's counterparties. Despite this, there can be no assurance that these efforts will be wholly successful in mitigating credit risk or that collateral pledged will be adequate.

The credit risk exposure from counterparties of merchant energy activities (excluding load requirements services contracts) are measured as either: (i) the sum of 60 days of accounts receivable, current fair value of open positions, and a credit value at risk, or (ii) the sum of delivered and unpaid accounts receivable and the current fair value of open positions. EME's subsidiaries enter into master agreements and other arrangements in conducting hedging and trading activities which typically provide for a right of setoff in the event of bankruptcy or default by the counterparty. Accordingly, EME's credit risk exposure from counterparties is based on net exposure under these agreements. At December 31, 2006, the amount of exposure as described above, broken down by the credit ratings of EME's counterparties, was as follows:

S&P Credit Rating	December 31, 2006
	(in millions)
A or higher	$ 87
A-	6
BBB+	86
BBB	29
BBB-	3
Below investment grade	1
Total	$ 212

EME's plants owned by unconsolidated affiliates in which EME owns an interest sell power under power purchase agreements. Generally, each plant sells its output to one counterparty. Accordingly, a default by a counterparty under a power purchase agreement, including a default as a result of a bankruptcy, would likely have a material adverse effect on the operations of such power plant.

In addition, coal for the Illinois Plants and the Homer City facilities is purchased from suppliers under contracts which may be for multiple years. A number of the coal suppliers to the Illinois Plants and the Homer City facilities do not currently have an investment grade credit rating and, accordingly, EME may have limited recourse to collect damages in the event of default by a supplier. EME seeks to mitigate this risk through diversification of its coal suppliers and through guarantees and other collateral arrangements when available. Despite this, there can be no assurance that these efforts will be successful in mitigating credit risk from coal suppliers.

EME's merchant plants sell electric power generally into the PJM market by participating in PJM's capacity and energy markets or transact capacity and energy on a bilateral basis. Sales into PJM accounted for approximately 58% of EME's consolidated operating revenues for the year ended December 31, 2006. Moody's rates PJM's senior unsecured debt Aa3. PJM, an ISO with over 300 member companies, maintains its own credit risk policies and does not extend unsecured credit to non-investment grade companies. Any losses due to a PJM member default are shared by all other members based upon a predetermined formula. At December 31, 2006, EME's account receivable due from PJM was $57 million.

Beginning in 2007, a significant amount of power from the Illinois Plants will be sold to Commonwealth Edison under load requirements services contracts. See "Commodity Price Risk—Energy Price Risk Affecting Sales from the Illinois Plants" for further discussion.

Interest Rate Risk

Interest rate changes can affect earnings and the cost of capital for capital improvements or new investments in power projects. EME mitigates the risk of interest rate fluctuations by arranging for fixed rate financing or variable rate financing with interest rate swaps, interest rate options or other hedging mechanisms for a number of its project financings. Based on the amount of variable rate long-term debt for which EME has not entered into interest rate hedge agreements at December 31, 2006, a 100-basis-point change in interest rates at December 31, 2006 would increase or decrease 2007 income before taxes by approximately $4 million. The fair market values of long-term fixed interest rate obligations are subject to interest rate risk. The fair market value of EME's total long-term obligations (including current portion) was $3.5 billion at December 31, 2006, compared to the carrying value of $3.2 billion. A 10% increase in market interest rates at December 31, 2006 would result in a decrease in the fair value of total long-term obligations by approximately $130 million. A 10% decrease in market interest rates at December 31, 2006 would result in an increase in the fair value of total long-term obligations by approximately $148 million.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information responding to Item 7A is filed with this report under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Financial Statements:

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

EME's management, with the participation of the company's Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of EME's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) or 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period, EME's disclosure controls and procedures are effective.

Internal Control Over Financial Reporting

There were no changes in EME's internal control over financial reporting (as such term is defined in Rules 13a-15(f) or 15d-15(f) under the Exchange Act) during the fiscal quarter ended December 31, 2006 that have materially affected, or are reasonably likely to materially affect, EME's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

EDISON MISSION ENERGY AND SUBSIDIARIES
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of Edison Mission Energy:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Edison Mission Energy and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the index appearing under Item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules based on our audits. We conducted our audits of these statements 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for stock-based compensation and defined benefit pension plans and other postretirement plans as of January 1, 2006 and December 31, 2006, respectively. As discussed in Note 7 to the consolidated financial statements, the Company changed the manner in which it accounts for asset retirement costs as of December 31, 2005. As discussed in Note 4 to the consolidated financial statements, the Company changed the manner in which it accounts for variable interest entities as of March 31, 2004.

/s/ PricewaterhouseCoopers LLP
Los Angeles, California
February 28, 2007

EDISON MISSION ENERGY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(In millions)

	Years Ended December 31,		
	2006	2005	2004
Operating Revenues	$ 2,239	$ 2,265	$ 1,653
Operating Expenses			
Fuel	645	617	619
Plant operations	511	493	495
Plant operating leases	176	177	186
Depreciation and amortization	144	134	152
Loss on lease termination, asset impairment and other charges	—	7	989
Administrative and general	140	154	149
Total operating expenses	1,616	1,582	2,590
Operating income (loss)	623	683	(937)
Other Income (Expense)			
Equity in income from unconsolidated affiliates	186	229	218
Impairment loss on equity method investment	—	(55)	—
Gain on sale of investments	—	—	43
Interest income	97	62	10
Interest expense	(279)	(300)	(298)
Loss on early extinguishment of debt	(146)	(4)	—
Other income (expense), net	23	7	(1)
Total other income (expense)	(119)	(61)	(28)
Income (loss) from continuing operations before income taxes and minority interest	504	622	(965)
Provision (benefit) for income taxes	189	208	(406)
Minority interest	1	—	(1)
Income (Loss) From Continuing Operations	316	414	(560)
Income from operations of discontinued subsidiaries (including gain on disposal of $533 million in 2004), net of tax (Note 5)	98	29	690
Income Before Accounting Change	414	443	130
Cumulative effect of change in accounting, net of tax (Notes 1 and 7)	—	(1)	—
Net Income	$ 414	$ 442	$ 130

The accompanying notes are an integral part of these consolidated financial statements.

EDISON MISSION ENERGY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	December 31, 2006	December 31, 2005
Assets		
Current Assets		
Cash and cash equivalents	$ 1,213	$ 1,155
Short-term investments	558	183
Accounts receivable—trade	178	337
Accounts receivable—affiliates	51	18
Inventory	158	120
Derivative assets	272	78
Margin and collateral deposits	69	561
Deferred taxes	—	155
Prepaid expenses and other	96	68
Total current assets	2,595	2,675
Investments in Unconsolidated Affiliates	367	405
Property, Plant and Equipment	4,272	3,856
Less accumulated depreciation and amortization	981	844
Net property, plant and equipment	3,291	3,012
Other Assets		
Deferred financing costs	45	43
Long-term derivative assets	114	90
Restricted cash	91	105
Rent payments in excess of levelized rent expense under plant operating leases	556	395
Long-term margin and collateral deposits	4	137
Other long-term assets	187	161
Total other assets	997	931
Total Assets	$ 7,250	$ 7,023

The accompanying notes are an integral part of these consolidated financial statements.

EDISON MISSION ENERGY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	December 31, 2006	December 31, 2005
Liabilities and Shareholder's Equity		
Current Liabilities		
Accounts payable	$ 69	$ 64
Accounts payable—affiliates	6	32
Accrued liabilities	270	207
Derivative liabilities	82	418
Interest payable	28	51
Deferred taxes	59	—
Current maturities of long-term obligations	132	74
Total current liabilities	646	846
Long-term obligations net of current maturities	3,035	3,330
Deferred taxes and tax credits	347	227
Deferred revenues	61	55
Long-term derivative liabilities	9	83
Other long-term liabilities	523	543
Total Liabilities	4,621	5,084
Minority Interest	47	29
Commitments and Contingencies (Notes 8, 9 and 12)		
Shareholder's Equity		
Common stock, par value $0.01 per share; 10,000 shares authorized; 100 shares issued and outstanding as of December 31, 2006 and 2005	64	64
Additional paid-in capital	2,174	2,228
Retained earnings (accumulated deficit)	243	(171)
Accumulated other comprehensive income (loss)	101	(211)
Total Shareholder's Equity	2,582	1,910
Total Liabilities and Shareholder's Equity	$ 7,250	$ 7,023

The accompanying notes are an integral part of these consolidated financial statements.

EDISON MISSION ENERGY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDER'S EQUITY
(In millions)

	Common Stock	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Shareholder's Equity
Balance at December 31, 2003	$ 64	$ 2,655	$ (743)	$ (22)	$ 1,954
Net income			130		130
Other comprehensive income				39	39
Cash contribution from parent		4			4
Dividend payable to parent		(305)			(305)
Cash dividends to parent		(74)			(74)
Payments to Edison International for stock option price appreciation on options exercised, net of tax		(8)			(8)
Other stock transactions, net		5			5
Balance at December 31, 2004	64	2,277	(613)	17	1,745
Net income			442		442
Other comprehensive loss				(228)	(228)
Non-cash equity contribution		20			20
Cash dividends to parent		(62)			(62)
Payments to Edison International for stock option price appreciation on options exercised, net of tax		(4)			(4)
Other stock transactions, net		(3)			(3)
Balance at December 31, 2005	64	2,228	(171)	(211)	1,910
Net income			414		414
Other comprehensive income				318	318
Adjustment to initially apply SFAS No. 158, net of tax				(6)	(6)
Non-cash equity contribution		8			8
Cash dividends to parent		(50)			(50)
Payments to Edison International for stock option price appreciation on options exercised, net of tax		(10)			(10)
Other stock transactions, net		(2)			(2)
Balance at December 31, 2006	$ 64	$ 2,174	$ 243	$ 101	$ 2,582

The accompanying notes are an integral part of these consolidated financial statements.

EDISON MISSION ENERGY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Years Ended December 31,		
	2006	2005	2004
Net Income	$ 414	$ 442	$ 130
Other comprehensive income (loss), net of tax:			
Foreign currency translation adjustments:			
Foreign currency translation adjustments, net of income tax expense of $4 for 2004	—	—	(18)
Reclassification adjustments for sale of investment in a foreign subsidiary	—	—	(127)
Minimum pension liability adjustment, net of income tax effect	(3)	—	10
Unrealized gains (losses) on derivatives qualified as cash flow hedges:			
Other unrealized holding gains (losses) arising during period, net of income tax expense (benefit) of $211, $(54) and $(6) for 2006, 2005 and 2004, respectively	309	(69)	86
Reclassification adjustments included in net income, net of income tax expense (benefit) of $(9), $107 and $(64) for 2006, 2005 and 2004, respectively	12	(159)	88
Other comprehensive income (loss)	318	(228)	39
Comprehensive Income	$ 732	$ 214	$ 169

The accompanying notes are an integral part of these consolidated financial statements.

EDISON MISSION ENERGY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2006	2005	2004
Cash Flows From Operating Activities			
Net income	$ 414	$ 442	$ 130
Less: Income from discontinued operations	(98)	(29)	(690)
Income (loss) from continuing operations, net	316	413	(560)
Adjustments to reconcile income (loss) to net cash provided by (used in) operating activities:			
Equity in income from unconsolidated affiliates	(183)	(227)	(215)
Distributions from unconsolidated affiliates	170	222	228
Depreciation and amortization	158	142	152
Minority interest	—	—	1
Deferred taxes and tax credits	100	(76)	(21)
Gain on sale of investments	—	—	(43)
Loss on early extinguishment of debt	146	4	—
Impairment charges	—	62	35
Cumulative effect of change in accounting, net of tax	—	1	—
Changes in operating assets and liabilities:			
Decrease (increase) in margin and collateral deposits	625	(656)	(30)
Decrease (increase) in accounts receivable	125	(118)	(52)
Decrease (increase) in inventory	(38)	(13)	11
Decrease (increase) in prepaid expenses and other	(26)	13	15
Increase in rent payments in excess of levelized rent expense	(161)	(117)	(59)
Increase in accounts payable and accrued liabilities	—	9	85
Increase (decrease) in interest payable	(23)	(4)	12
Decrease (increase) in derivative assets and liabilities	(72)	41	13
Other operating—assets	(1)	4	13
Other operating—liabilities	(5)	61	62
	1,131	(239)	(353)
Operating cash flow from discontinued operations	94	20	(434)
Net cash provided by (used in) operating activities	1,225	(219)	(787)
Cash Flows From Financing Activities			
Borrowing on long-term debt	1,450	330	1,795
Payments on long-term debt agreements	(1,683)	(712)	(1,706)
Cash contribution from parent	—	—	3
Cash dividends to parent	(51)	(367)	(74)
Payments to affiliates related to stock-based awards	(27)	(18)	(5)
Excess tax benefits related to stock option exercises	7	—	—
Premium paid on extinguishment of debt and financing costs	(157)	(6)	(34)
	(461)	(773)	(21)
Financing cash flow from discontinued operations	—	—	(144)
Net cash used in financing activities	(461)	(773)	(165)
Cash Flows From Investing Activities			
Capital expenditures	(310)	(61)	(55)
Proceeds from return of capital	41	—	—
Purchase of interest of acquired companies	(18)	(154)	—
Proceeds from sale of interest in projects	43	—	118
Proceeds from sale of discontinued operations	—	124	2,740
Purchase of short-term investments	(512)	(183)	(301)
Maturities and sales of short-term investments	137	140	181
Decrease in restricted cash	14	41	30
Investments in other assets	(101)	(41)	(6)
	(706)	(134)	2,707
Investing cash flow from discontinued operations	—	5	18
Net cash provided by (used in) investing activities	(706)	(129)	2,725
Effect of exchange rate changes on cash	—	—	50
Effect of consolidation of variable interest entities on cash	—	3	1
Effect on cash from deconsolidation of subsidiary	—	—	(34)
Net increase (decrease) in cash and cash equivalents	58	(1,118)	1,790
Cash and cash equivalents at beginning of period	1,155	2,274	484
Cash and cash equivalents at end of period	1,213	1,156	2,274
Cash and cash equivalents classified as part of discontinued operations	—	(1)	(2)
Cash and cash equivalents of continuing operations	$ 1,213	$ 1,155	$ 2,272

The accompanying notes are an integral part of these consolidated financial statements.

Note 1. Summary of Significant Accounting Policies

EME is a wholly owned subsidiary of MEHC, which is a wholly owned subsidiary of Edison Mission Group Inc., which is a wholly owned, non-utility subsidiary of Edison International, which is also the parent holding company of SCE. Through its subsidiaries, EME is engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from independent power production facilities. EME also conducts hedging and energy trading activities in power markets open to competition.

Each of EME's direct and indirect subsidiaries is organized as a legal entity separate and apart from EME and its other subsidiaries. Any asset of any of those subsidiaries may not be available to satisfy EME's obligations or any obligations of EME's other subsidiaries. However, unrestricted cash or other assets which are available for distribution may, subject to business and tax considerations, applicable law and the terms of financing arrangements binding on these subsidiaries, be advanced, loaned, paid as dividends or otherwise distributed or contributed to EME or its affiliates.

Basis of Presentation

The consolidated financial statements include the accounts of EME and all subsidiaries and partnerships in which EME has a controlling interest and variable interest entities in which EME is deemed the primary beneficiary. EME's investments in unconsolidated affiliates in which a significant, but less than controlling, interest is held and variable interest entities, in which EME is not deemed to be the primary beneficiary, are accounted for by the equity method. Refer to Note 4—Acquisitions and Consolidations—Consolidations for a discussion of EME's adoption of an accounting standard on variable interest entities. All significant intercompany transactions and balances have been eliminated in the consolidated financial statements.

On April 1, 2006, EME received, as a capital contribution, ownership interests in a portfolio of wind projects located in Iowa and Minnesota and a small biomass project. See Note 4—Acquisitions and Consolidations, for further discussion. These projects were previously owned by EME's affiliate, Edison Capital. EME accounted for this acquisition at Edison Capital's historical cost as a transaction between entities under common control. Therefore, these consolidated financial statements include the results of operations, financial position and cash flows of the acquired projects as though EME had such ownership throughout the periods presented.

Certain prior year reclassifications have been made to conform to the current year financial statement presentation. Except as indicated, amounts reflected in the notes to the consolidated financial statements relate to continuing operations of EME.

The preparation of financial statements in conformity with GAAP requires EME to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ from those estimates.

Cash Equivalents and Short-term Investments

Cash equivalents consist of time deposits, including certificates of deposit ($289 million and $411 million at December 31, 2006 and 2005, respectively), and other investments ($824 million and

$712 million at December 31, 2006 and 2005, respectively) with original maturities of three months or less. For a discussion of restricted cash, see "—Restricted Cash."

At December 31, 2006 and 2005, EME had classified all marketable debt securities as held-to-maturity under SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." The securities were carried at amortized cost plus accrued interest which approximated their fair value. Gross unrealized holding gains and losses were not material.

Held-to-maturity securities, which all mature within one year, consisted of the following:

	December 31, 2006	December 31, 2005
	(in millions)	
Commercial paper	$ 417	$ 99
Certificates of deposit	141	34
Time deposits	—	50
Total	$ 558	$ 183

In addition, EME had marketable securities classified as available-for-sale under SFAS No. 115 during 2005 and 2004. Sales of auction rate securities were $140 million and $181 million in 2005 and 2004, respectively. Purchases of auction rate securities were $301 million in 2004. Unrealized gains and losses from investments in these securities were not material.

Deferred Financing Costs

Bank, legal and other direct costs incurred in connection with obtaining financing are deferred and amortized as interest expense on a basis which approximates the effective interest rate method over the term of the related debt. Accumulated amortization of these costs at December 31, 2006 and 2005 amounted to $24 million and $25 million, respectively. Amortization of deferred financing costs charged to operations was $5 million in both 2006 and 2005.

Derivative Instruments

SFAS No. 133, as amended and interpreted by other related accounting literature, establishes accounting and reporting standards for derivative instruments (including certain derivative instruments embedded in other contracts). SFAS No. 133 requires companies to record derivatives on their balance sheets as either assets or liabilities measured at their fair value unless exempted from derivative treatment as a normal sale and purchase. All changes in the fair value of derivatives are recognized currently in earnings unless specific hedge criteria are met, which requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting.

SFAS No. 133 sets forth the accounting requirements for cash flow hedges. SFAS No. 133 provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, must be recognized currently in earnings.

Financial instruments that are utilized for trading purposes are measured at fair value and included in the balance sheet as derivative assets or liabilities. In the absence of quoted market prices, financial instruments are valued at fair value, considering time value, volatility of the underlying commodity, and other factors as determined by EME. Resulting gains and losses are recognized in operating revenues in the accompanying consolidated income statements in the period of change. Derivative assets include the fair value of open financial positions related to trading activities and the present value of net amounts receivable from structured transactions. Derivative liabilities include the fair value of open financial positions related to trading activities. The results of derivative activities are recorded as part of cash flows from operating activities in the accompanying consolidated statements of cash flows.

Where EME's derivative instruments are subject to a master netting agreement and the criteria of FASB Interpretation (FIN) 39 "Offsetting of Amounts Related to Certain Contracts" are met, EME presents its derivative assets and liabilities on a net basis in its balance sheet.

Impairment of Investments and Long-Lived Assets

EME evaluates the impairment of its investments in projects and other long-lived assets based on a review of estimated future cash flows expected to be generated whenever events or changes in circumstances indicate that the carrying amount of such investments or assets may not be recoverable. If the carrying amount of the investment or asset exceeds the amount of the expected future cash flows, undiscounted and without interest charges, then an impairment loss for EME's investments in projects and other long-lived assets is recognized in accordance with Accounting Principles Board Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock" and SFAS No. 144, respectively.

Income Taxes

EME is included in the consolidated federal and state income tax returns of Edison International and participates in tax-allocation and payment agreements with other subsidiaries of Edison International. EME calculates its tax provision in accordance with these tax agreements. EME's current tax liability or benefit is determined on a "with and without" basis. This means Edison International computes its combined federal and state tax liabilities including and excluding EME's taxable income or loss and state apportionment factors. This method is similar to a separate company return, except that EME recognizes, without regard to separate company limitations, additional tax liabilities or benefits based on the impact to the combined group of including EME's taxable income or losses and state apportionment factors.

EME accounts for deferred income taxes using the asset-and-liability method, wherein deferred tax assets and liabilities are recognized for future tax consequences of temporary differences between the carrying amounts and the tax bases of assets and liabilities using enacted income tax rates. Investment and energy tax credits are deferred and amortized over the term of the power purchase agreement of the respective project. Income tax accounting policies are discussed further in Note 10—Income Taxes.

EME's investments in wind-powered electric generation projects qualify for federal production tax credits under Section 45 of the Internal Revenue Code. Such credits are allowable for production during the 10-year period after a qualifying wind energy facility is placed into service. Production tax credits are recognized by EME when the corresponding electricity is produced.

Inventory

Inventory is stated at the lower of weighted average cost or market. Inventory at December 31, 2006 and December 31, 2005 consisted of the following:

	2006	2005
	(in millions)	
Coal and fuel oil	$ 112	$ 77
Spare parts, materials and supplies	46	43
Total	$ 158	$ 120

Margin and Collateral Deposits

Margin and collateral deposits include cash deposited with counterparties and brokers as credit support under energy contracts. The amount of margin and collateral deposits generally varies based on changes in fair value of the related positions.

New Accounting Pronouncements

Accounting Principles Adopted

Statement of Financial Accounting Standards No. 123(R)—

SFAS No. 123(R) requires companies to use the fair value accounting method for stock-based compensation. EME implemented SFAS No. 123(R) in the first quarter of 2006 and applied the modified prospective transition method. Under the modified prospective method, SFAS No. 123(R) was applied effective January 1, 2006 to the unvested portion of awards previously granted and will be applied to all prospective awards. Prior financial statements were not restated under this method. SFAS No. 123(R) resulted in the recognition of expense for all stock-based compensation awards. In addition, EME elected to calculate the pool of windfall tax benefits as of the adoption of SFAS No. 123(R) based on the method (also known as the short-cut method) proposed in FSP FAS 123(R)-3, "Transition Election to Accounting for the Tax Effects of Share-Based Payment Awards." Prior to January 1, 2006, EME used the intrinsic value method of accounting, which resulted in no recognition of expense for Edison International stock options. Prior to adoption of SFAS No. 123(R), EME presented all tax benefits of deductions resulting from the exercise of stock options as a component of operating cash flows under the caption "Other operating—liabilities" in the consolidated statements of cash flows. SFAS No. 123(R) requires the cash flows resulting from the tax benefits that occur from estimated tax deductions in excess of the compensation cost recognized for those options (excess tax benefits) to be classified as financing cash flows. The $7 million excess tax benefit is classified as a financing cash inflow in 2006.

Due to the adoption of SFAS No. 123(R), EME recorded a cumulative effect adjustment that increased net income by approximately $0.4 million, net of tax, in the first quarter of 2006, mainly to reflect the change in the valuation method for performance shares classified as liability awards and the use of forfeiture estimates.

FASB Staff Position FIN 46(R)-6—

In April 2006, the FASB issued Staff Position FIN 46(R)-6, "Determining Variability to be Considered in Applying FIN 46(R)." FIN 46(R)-6 states that the variability to be considered in applying FIN 46(R) shall be based on an analysis of the design of the entity following a two-step process. The first step is to analyze the nature of the risks in the entity. The second step would be to determine the purpose(s) for which the entity was created and determine the variability (created by the risks identified in Step 1) the entity is designed to create and pass along to its interest holders. The guidance in this FASB Staff Position was effective prospectively beginning July 1, 2006, although companies had until December 31, 2006 to elect retrospective applications. EME adopted FIN 46(R)-6 prospectively beginning July 1, 2006. Applying the guidance had no effect on EME's consolidated financial statements for the year ending December 31, 2006.

Statement of Financial Accounting Standards No. 158—

In September 2006, the FASB issued SFAS No. 158, which amends the accounting by employers for defined benefit pension plans and postretirement benefits other than pensions. SFAS No. 158 requires companies to recognize the overfunded or underfunded status of a defined benefit pension and other postretirement plans as assets or liabilities in their balance sheet; the assets or liabilities are offset through other comprehensive income. EME adopted SFAS No. 158 prospectively on December 31, 2006. SFAS No. 158 also requires companies to align the measurement dates for their plans to their fiscal year-ends; EME already has a fiscal year-end measurement date for all of its postretirement plans. Upon adoption, EME recorded additional postretirement benefit liabilities of $10 million (included in other long-term liabilities) and a reduction to accumulated other comprehensive income (a component of shareholder's equity) of $6 million, net of tax.

Staff Accounting Bulletin No. 108—

In September 2006, the SEC issued Staff Accounting Bulletin (SAB) No. 108, which provides interpretive guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. SAB No. 108 requires additional quantitative testing to determine whether a misstatement is material. EME implemented SAB No. 108 for the filing of its Annual Report on Form 10-K for the year ended December 31, 2006. Applying the guidance had no effect on EME's consolidated financial statements for the year ended December 31, 2006.

Accounting Principles Not Yet Adopted

Statement of Financial Accounting Standards Interpretation No. 48—

In July 2006, the FASB issued SFAS Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," that clarifies the accounting for uncertain tax positions. An enterprise would be required to recognize, in its financial statements, the best estimate of the impact of a tax position by determining if the weight of the available evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained on audit. EME will adopt the new interpretation in the first quarter of 2007. The new interpretation is not expected to result in a material adjustment to shareholder's equity.

Statement of Financial Accounting Standards No. 155—

In February 2006, the FASB issued SFAS No. 155, which amends SFAS No. 133 and SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities." SFAS No. 155 allows financial instruments that have embedded derivatives to be accounted for at fair value at acquisition, at issuance, or when a previously recognized financial instrument is subject to a remeasurement event, on an instrument-by-instrument basis, in cases in which a derivative would otherwise have to be bifurcated. SFAS No. 155 is effective for all financial instruments acquired, issued, or subject to remeasurement after January 1, 2007. The fair value election provided for in paragraph 4(c) of this Statement may also be applied upon adoption of this Statement for hybrid financial instruments that had been bifurcated under paragraph 12 of SFAS No. 133 prior to the adoption of this Statement. EME does not expect the adoption of this standard to have a material impact on EME's consolidated financial statements.

Statement of Financial Accounting Standards No. 157—

In September 2006, the FASB issued a new accounting standard on fair value measurements (SFAS No. 157). SFAS No. 157 clarifies the definition of fair value, establishes a framework for measuring fair value and expands the disclosures on fair value measurements. EME will adopt SFAS No. 157 on January 1, 2008. EME is currently evaluating the impact of adopting SFAS No. 157 on its consolidated financial statements.

Planned Major Maintenance

Certain of EME's plant facilities' major pieces of equipment require major maintenance on a periodic basis. These costs are expensed as incurred.

Project Development Costs

EME capitalizes direct costs incurred in developing new projects upon attainment of principal activities needed to commence procurement and construction. These costs consist of professional fees, salaries, permits, and other directly related development costs incurred by EME. The capitalized costs are amortized over the life of operational projects or charged to expense if management determines the costs to be unrecoverable.

Property, Plant and Equipment

Property, plant and equipment, including leasehold improvements and construction in progress, are capitalized at cost and are principally comprised of EME's majority-owned subsidiaries' plants and related facilities. Depreciation and amortization are computed by using the straight-line method over the useful life of the property, plant and equipment and over the lease term for leasehold improvements.

As part of the acquisition of the Illinois Plants and the Homer City facilities, EME acquired emission allowances under the US EPA's Acid Rain Program. Although the emission allowances granted under this program are freely transferable, EME intends to use substantially all the emission allowances in the normal course of its business to generate electricity. Accordingly, EME has classified emission allowances expected to be used by EME to generate power as part of property, plant and equipment. Acquired emission allowances will be amortized over the estimated lives of the plants on a straight-line basis.

Useful lives for property, plant, and equipment are as follows:

Power plant facilities	3-30 years
Leasehold improvements	Shorter of life of lease or estimated useful life
Emission allowances	25-33.75 years
Equipment, furniture and fixtures	3-7 years
Capitalized leased equipment	5 years

Interest incurred on funds borrowed by EME to finance project construction is capitalized. Capitalization of interest is discontinued when the projects are completed and deemed operational. Such capitalized interest is included in investment in energy projects and property, plant and equipment.

Capitalized interest is amortized over the depreciation period of the major plant and facilities for the respective project.

	Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Interest incurred	$ 287	$ 300	$ 298
Interest capitalized	(8)	—	—
	$ 279	$ 300	$ 298

Rent Expense

Rent expense under operating leases is levelized over the terms of the leases. Operating leases primarily consist of long-term leases for the Powerton, Joliet and Homer City power plants. See Note 12—Commitments and Contingencies—Lease Commitments for additional information on these sale-leaseback transactions.

Restricted Cash

Several cash balances are restricted primarily to pay amounts required for debt payments and letter of credit expenses. The total restricted cash included in EME's consolidated balance sheet was $91 million at December 31, 2006 and $105 million at December 31, 2005. Included in restricted cash were debt service reserves of $40 million at both December 31, 2006 and 2005 and collateral reserves of $38 million and $65 million at December 31, 2006 and 2005, respectively.

Revenue Recognition

EME is primarily an independent power producer, operating a portfolio of owned and leased plants and plants which are accounted for under the equity method. EME's subsidiaries enter into power and fuel hedging, optimization transactions and energy trading contracts, all subject to market conditions. One of EME's subsidiaries executes these transactions primarily through the use of physical forward commodity purchases and sales and financial commodity swaps and options. With respect to its physical forward contracts, EME's subsidiaries generally act as the principal, take title to the commodities, and assume the risks and rewards of ownership. Therefore, EME's subsidiaries record settlement of non-trading physical forward contracts on a gross basis. Consistent with Emerging Issues Task Force No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments that are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes," EME nets the cost of purchased power against related third party sales in markets that use locational marginal pricing, currently PJM. Financial swap and option transactions are settled net and, accordingly, EME's subsidiaries do not take title to the underlying commodity. Therefore, gains and losses from settlement of financial swaps and options are recorded net. Managed risks typically include commodity price risk associated with fuel purchases and power sales.

EME records revenue and related costs as electricity is generated or services are provided unless EME is subject to SFAS No. 133 and does not qualify for the normal sales and purchases exception.

In addition, revenues under certain long-term power sales contracts subject to Emerging Issues Task Force No. 91-6, "Revenue Recognition of Long-term Power Sales Contracts," are recognized based on the output delivered at the lower of the amount billable or the average rate over the contract term. The excess of the amounts billed over the portion recorded as revenue is reflected in deferred revenues in the consolidated balance sheet.

Stock-Based Compensation

EME's stock-based compensation plans primarily include the issuance of Edison International stock options and performance shares. Edison International usually does not issue new common stock for equity awards settled. Rather, a third party is used to facilitate the exercise of stock options and the purchase and delivery of outstanding common stock for settlement of performance shares. Edison International has approximately 13.5 million shares remaining for future issuance under its stock-based compensation plans, which are described more fully in Note 11—Compensation and Benefit Plans—Stock-Based Compensation.

Prior to January 1, 2006, EME accounted for these plans using the intrinsic value method. Upon grant, no stock-based compensation cost for stock options was reflected in net income, as the grant date was the measurement date, and all options granted under these plans had an exercise price equal to the market value of the underlying common stock on the date of grant. Previously, stock-based compensation cost for performance shares was remeasured at each reporting period and related compensation expense was adjusted. As discussed in "New Accounting Pronouncements" above, effective January 1, 2006, EME implemented SFAS No. 123(R) that requires companies to use the fair value accounting method for stock-based compensation resulting in the recognition of expense for all stock-based compensation awards. EME recognizes stock-based compensation expense on a straight-line basis over the requisite service period. EME recognizes stock-based compensation expense for awards granted to retirement-eligible participants as follows: for stock-based awards granted prior to January 1, 2006, EME recognized stock-based compensation expense over the explicit requisite service period and accelerated any remaining unrecognized compensation expense when a participant actually retired; for awards granted or modified after January 1, 2006 to participants who are retirement-eligible or will become retirement-eligible prior to the end of the normal requisite service period for the award, stock-based compensation is recognized on a prorated basis over the initial year or over the period between the date of grant and the date the participant first becomes eligible for retirement. If EME recognized stock-based compensation expense for awards granted prior to January 1, 2006, over a period to the date the participant first became eligible for retirement, stock-based compensation would have decreased $1 million for 2006, would have increased $1 million for 2005 and would have increased $2 million for 2004.

Total stock-based compensation expense (reflected in the caption "Administrative and general" on the consolidated statements of income) was $11 million, $21 million and $21 million for 2006, 2005 and 2004, respectively. The income tax benefit recognized in the income statement was $4 million, $8 million and $8 million for 2006, 2005 and 2004, respectively.

The following table illustrates the effect on net income if EME had used the fair-value accounting method for 2005 and 2004.

	Years Ended December 31,	
	2005	2004
	(in millions)	
Net income, as reported	$ 442	$ 130
Add: stock-based compensation expense using the intrinsic value accounting method—net of tax	13	14
Less: stock-based compensation expense using the fair value accounting method, net of tax	(10)	(12)
Pro forma net income	$ 445	$ 132

Note 2. Restructuring, Loss on Lease Termination, Asset Impairment and Other Charges

Restructuring Costs

During the first quarter of 2005, EME initiated a review of its domestic organization to better align its resources with its domestic business requirements. Management and organizational changes have been implemented to streamline EME's reporting relationships and eliminate its regional management structure. As a result of these changes, EME recorded charges of approximately $13 million (pre-tax) in 2005 for severance and related costs. These charges were included in administrative and general expense on EME's consolidated statement of income.

Loss on Lease Termination, Asset Impairment and Other Charges

During 2004, EME recorded loss on lease termination, asset impairment and other charges of $989 million. On April 27, 2004, EME's subsidiary, Midwest Generation, terminated the Collins Station lease through a negotiated transaction with the lease equity investor. Midwest Generation made a lease termination payment of approximately $960 million. This amount represented the $774 million of lease debt outstanding, plus accrued interest, and the amount owed to the lease equity investor for early termination of the lease. Midwest Generation received title to the Collins Station as part of the transaction. EME recorded a pre-tax loss of approximately $956 million (approximately $587 million after tax) due to termination of the lease and the planned decommissioning of the asset and disposition of excess inventory.

Following the termination of the Collins Station lease, Midwest Generation announced plans on May 28, 2004 to permanently cease operations at the Collins Station by December 31, 2004 and decommission the plant. By the fourth quarter of 2004, the Collins Station was decommissioned and all units were permanently retired from service, disconnected from the grid, and rendered inoperable, with all operating permits surrendered. In September 2004, EME recorded a pre-tax impairment charge of $5 million resulting from the termination of the power purchase agreement effective September 30, 2004 for the two units at the Collins Station that remained under contract. In addition, EME recognized a $4 million pre-tax charge for exit costs recorded as part of plant operations on EME's consolidated income statement related to reducing the workforce in Illinois during the fourth quarter of 2004.

In September 2004, management completed an analysis of future competitiveness in the expanded PJM marketplace of its eight remaining small peaking units in Illinois. Based on this analysis, management decided to decommission six of the eight small peaking units. As a result of the decision to decommission the units, projected future cash flows associated with the Illinois peaking units were less than the book value of the units, resulting in an impairment under SFAS No. 144. During the third quarter of 2004, EME recorded a pre-tax impairment charge of $29 million (approximately $18 million after tax).

Note 3. Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss), including discontinued operations, consisted of the following:

	Unrealized Gains (Losses) on Cash Flow Hedges	Minimum Pension Liability Adjustment	Unrecognized Losses and Prior Service Costs, Net	Accumulated Other Comprehensive Income (Loss)
			(in millions)	
Balance at December 31, 2004	$ 18	$ (1)	$ —	$ 17
Change for 2005	(228)	—	—	(228)
Balance at December 31, 2005	(210)	(1)	—	(211)
Change for 2006	321	(3)	—	318
SFAS No. 158 adjustments(1)	—	4	(10)	(6)
Balance at December 31, 2006	$ 111	$ —	$ (10)	$ 101

(1) Represents adjustments to initially apply SFAS No. 158 discussed in Note 11—Compensation and Benefit Plans.

Unrealized gains on cash flow hedges, net of tax, at December 31, 2006, include unrealized gains on commodity hedges related to Midwest Generation and EME Homer City futures and forward electricity contracts that qualify for hedge accounting. These gains arise because current forecasts of future electricity prices in these markets are lower than the contract prices. The change from unrealized losses to unrealized gains during 2006 resulted from a decrease in market prices for power and hedge contracts that settled during 2006.

As EME's hedged positions for continuing operations are realized, approximately $94 million, after tax, of the net unrealized gains on cash flow hedges at December 31, 2006 are expected to be reclassified into earnings during the next 12 months. Management expects that reclassification of net unrealized gains will offset energy revenue recognized at market prices. Actual amounts ultimately reclassified into earnings over the next 12 months could vary materially from this estimated amount as a result of changes in market conditions. The maximum period over which a cash flow hedge is designated is through December 31, 2009.

Under SFAS No. 133, the portion of a cash flow hedge that does not offset the change in value of the transaction being hedged, which is commonly referred to as the ineffective portion, is immediately recognized in earnings. EME recorded net losses of approximately $6 million, $65 million and $13 million in 2006, 2005 and 2004, respectively, representing the amount of cash flow hedges' ineffectiveness for continuing operations, reflected in operating revenues in EME's consolidated income statements.

Note 4. Acquisitions and Consolidations

Transfer of Wind Projects from an Affiliate

On April 1, 2006, EME received, as a capital contribution, ownership interests in a portfolio of wind projects located in Iowa and Minnesota and a small biomass project. The acquisition was accounted for as a transaction between entities under common control. As such, the assets and liabilities of the projects acquired were recorded at historical cost on the acquisition date for a net book value of approximately $76 million. The principal components of the net book value of assets and liabilities at April 1, 2006 are current assets ($8 million), property, plant and equipment, net ($156 million), other non-current assets ($42 million), deferred income ($56 million) and deferred income taxes ($59 million). EME's historical financial statements have been adjusted for all periods presented to reflect the acquisition as though EME had ownership of such projects, including a distribution paid by Edison Capital to its parent in 2005. Summarized results of the projects acquired for periods presented prior to the acquisition date of April 1, 2006 are as follows:

	Three Months Ended March 31,	Years Ended December 31,	
	2006	2005	2004
	(unaudited)	(in millions)	
Total operating revenues	$ 4	$ 17	$ 14
Income (loss) before income taxes	(1)	(3)	3
Benefit for income taxes	(3)	(13)	(5)
Income from continuing operations	2	10	8

Acquisitions

Wildorado Wind Project

On January 5, 2006, EME completed a transaction with Cielo Wildorado, G.P., LLC and Cielo Capital, L.P. to acquire a 99.9% interest in Wildorado Wind, L.P., which owns a 161 MW wind farm located in the panhandle of northern Texas, referred to as the Wildorado wind project. The acquisition included all development rights, title and interest held by Cielo in the Wildorado wind project, except for a small minority stake in the project retained by Cielo. The total purchase price was $29 million. As of December 31, 2006, a cash payment of $18 million had been made towards the purchase price. This project started construction in April 2006 and is scheduled for completion during April 2007, with total construction costs, excluding capitalized interest, estimated to be $270 million. The acquisition was accounted for utilizing the purchase method. The fair value of the Wildorado wind project was equal to the purchase price and as a result, the total purchase price was allocated to property, plant and equipment in EME's consolidated balance sheet.

San Juan Mesa Project

On December 27, 2005, EME completed a transaction with Padoma Project Holdings, LLC to acquire a 100% interest in the San Juan Mesa Wind Project, which owns a 120 MW wind power generation facility located in New Mexico, referred to as the San Juan Mesa wind project. The total purchase price was $156.5 million. The acquisition was funded with cash. The acquisition was accounted for utilizing the purchase method. The fair value of the San Juan Mesa wind project was equal to the purchase price and as a result, the entire purchase price was allocated to property, plant and equipment in EME's consolidated balance sheet. EME's consolidated statement of income reflected the operations of the San Juan Mesa project beginning January 1, 2006. The pro forma effects of the San Juan Mesa wind project acquisition on EME's consolidated financial statements were not material.

Consolidations

Variable Interest Entities

In December 2003, the FASB issued FIN 46(R). This Interpretation defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk or a controlling financial interest in the entity. Under this Interpretation, the primary beneficiary is the variable interest holder that absorbs a majority of expected losses; if no variable interest holder meets these criteria, then it is the variable interest holder that receives a majority of the expected residual returns. The primary beneficiary is required to consolidate the variable interest entity unless specific exceptions or exclusions are met.

Consolidation of Special Purpose Entities—

U.S. Wind Force is a development stage enterprise formed to develop wind projects in West Virginia, Pennsylvania and Maryland. In December 2006, a subsidiary of EME entered into a loan agreement with U.S. Wind Force to fund the redemption of a membership interest held by another party, repayment of loans, distributions to equity holders and to fund future development of wind projects. In accordance with FIN 46(R), EME is the primary beneficiary and, accordingly, consolidated U.S. Wind Force at December 15, 2006. The assets consolidated included $17 million of intangible assets, primarily related to project development rights, and are classified as part of other long-term assets in EME's consolidated balance sheet. As project development is completed, the project development rights will be considered part of property, plant and equipment and depreciated over the estimated useful lives of the respective projects.

Wildorado Wind, L.P. is a special purpose entity formed to develop the Wildorado wind project, a 161 MW wind power generating facility to be located in Texas. A subsidiary of EME entered into a loan agreement with Wildorado Wind to fund turbine payments for the Wildorado wind project. In accordance with FIN 46(R), EME was the primary beneficiary and, accordingly, consolidated Wildorado Wind at December 31, 2005. On January 5, 2006, EME completed the purchase of development rights for the Wildorado wind project. See "—Acquisitions—Wildorado Wind Project" for further discussion.

Consolidation of Wind Projects—

Effective March 31, 2004, three wind projects were consolidated and at December 31, 2005, two additional wind projects were consolidated in accordance with FIN 46(R). These projects were funded with nonrecourse debt totaling $27 million at December 31, 2006. Properties serving as collateral for these loans had a carrying value of $56 million and are classified as property, plant and equipment on EME's consolidated balance sheet at December 31, 2006.

Deconsolidation of Variable Interest Entities—

In accordance with FIN 46(R), EME determined that it was not the primary beneficiary of the Doga project and, accordingly, deconsolidated the project at March 31, 2004.

Variable Interest Entities—

EME completed a review of the application of FIN 46(R) to its subsidiaries and affiliates and concluded that it had significant variable interests in variable interest entities as defined in this Interpretation. As of December 31, 2006, these entities consisted of five equity investments (the Big 4 projects and the Sunrise project) that had interests in natural gas-fired facilities with a total generating capacity of 1,782 MW. An operations and maintenance subsidiary of EME operates the Big 4 projects, but EME does not supply the fuel consumed or purchase the power generated by these facilities. EME determined that it is not the primary beneficiary in these entities; accordingly, EME continues to account for its variable interests on the equity method. EME's maximum exposure to loss in these variable interest entities is generally limited to its investment in these entities, which totaled $320 million as of December 31, 2006.

Note 5. Divestitures

Dispositions

On March 7, 2006, EME completed the sale of a 25% ownership interest in the San Juan Mesa wind project to Citi Renewable Investments I LLC, a wholly owned subsidiary of Citicorp North America, Inc. Proceeds from the sale were $43 million. EME recorded a pre-tax gain on the sale of approximately $4 million during the first quarter of 2006.

On March 31, 2004, EME completed the sale of 100% of its stock of Mission Energy New York, Inc., which in turn owned a 50% partnership interest in Brooklyn Navy Yard, to a third party for a sales price of approximately $42 million. EME recorded an impairment charge of $53 million during the fourth quarter of 2003 related to the planned disposition of this investment and a pre-tax loss of approximately $4 million during the first quarter of 2004 due to changes in the terms of the sale.

On January 7, 2004, EME completed the sale of 100% of its stock of Edison Mission Energy Oil & Gas, which in turn held minority interests in Four Star Oil & Gas, to Medicine Bow Energy Corporation. Proceeds from the sale were approximately $100 million. EME recorded a pre-tax gain on the sale of approximately $47 million during the first quarter of 2004.

Discontinued Operations

Tri Energy Project

On February 3, 2005, EME sold its 25% equity interest in the Tri Energy project pursuant to a Purchase Agreement, dated December 15, 2004, by and between EME and IPM for approximately $20 million. EME recorded an impairment charge of approximately $5 million during the fourth quarter of 2004 related to the planned disposition of this investment. The sale of this investment had no significant effect on net income in the first quarter of 2005.

CBK Project

On January 10, 2005, EME sold its 50% equity interest in the CBK project pursuant to a Purchase Agreement, dated November 5, 2004, by and between EME and Corporacion IMPSA S.A. Proceeds from the sale were approximately $104 million. EME recorded a pre-tax gain on the sale of approximately $9 million during the first quarter of 2005.

MEC International B.V.

On December 16, 2004, EME sold the stock and related assets of MEC International B.V. (MECIBV) pursuant to a Purchase Agreement, dated July 29, 2004, by and between EME and IPM. The purchase agreement was entered into following a competitive bidding process. The sale of MECIBV included the sale of EME's interests in ten electric power generating projects or companies located in Europe, Asia, Australia, and Puerto Rico. Consideration from the sale of MECIBV and related assets was $2.0 billion.

Contact Energy

On September 30, 2004, EME sold its 51.2% interest in Contact Energy to Origin Energy New Zealand Limited pursuant to a Purchase Agreement, dated July 20, 2004. The purchase agreement was entered into following a competitive bidding process. Consideration for the sale was NZ$1,101 million (approximately US$739 million) in cash and NZ$535 million (approximately US$359 million) of debt assumed by the purchaser.

Lakeland Project

EME previously owned a 220 MW power plant located in the United Kingdom, referred to as the Lakeland project. An administrative receiver was appointed in 2002 as a result of a default by the project's counterparty, a subsidiary of TXU Europe Group plc. Following a claim for termination of the power sales agreement, the Lakeland project received a settlement of £116 million (approximately $217 million). EME is entitled to receive the remaining amount of the settlement after payment of creditor claims. As creditor claims have been settled, EME has received to date payments of £13 million (approximately $24 million) in 2005, £72 million (approximately $125 million) in 2006 and £4 million (approximately $8 million) in January 2007. The after-tax income attributable to the Lakeland project was $85 million and $24 million for 2006 and 2005, respectively, and none in 2004. Beginning in 2002, EME reported the Lakeland project as discontinued operations and accounts for its ownership of Lakeland Power on the cost method (earnings are recognized as cash is distributed from the project).

Summarized Financial Information for Discontinued Operations

In accordance with SFAS No. 144, all the projects discussed above are classified as discontinued operations in the accompanying consolidated statements of income. Previously issued statements of operations have been restated to reflect discontinued operations reported subsequent to the original issuance date. Summarized results of discontinued operations are as follows:

	Years Ended December 31,		
	2006	2005	2004
	(in millions)		
Total operating revenues	$ —	$ —	$ 1,281
Income (loss) before income taxes and minority interest	119	(20)	256
Provision (benefit) for income taxes	21	(44)	48
Minority interest	—	—	51
Income from operations of discontinued foreign subsidiaries	98	24	157
Gain on sale before income taxes	—	9	532
Gain on sale after income taxes	—	5	533

During the fourth quarter of 2006, EME recorded a tax benefit adjustment of $22 million, which resulted from resolution of a tax uncertainty pertaining to the ownership interest in a foreign project. EME's payment of $34 million during the second quarter of 2006 related to an indemnity to IPM for matters arising out of the exercise by one of its project partners of a purported right of first refusal resulted in a $3 million additional loss recorded in 2006. During the fourth quarter of 2005, EME recorded an after-tax charge of $25 million related to a tax indemnity for a project sold to IPM in December 2004. This charge related to an adverse tax court ruling in Spain, which the local company appealed. During the third quarter of 2005, EME recorded tax benefit adjustments of $28 million, which resulted from completion of the 2004 federal and California income tax returns and quarterly review of tax accruals. Most of the tax adjustments are related to the sale of the international projects in December 2004 and are included in "Provision (benefit) for income taxes" in the above table.

Assets of $1 million and liabilities of $4 million associated with discontinued operations are included on the consolidated balance sheet at December 31, 2005 in other long-term assets and other long-term liabilities, respectively.

EME has operated as one segment since the third quarter of 2004 due to the sale of most of its international assets. Prior periods' segment information has not been presented due to lack of continuing significance.

Note 6. Investments in Unconsolidated Affiliates

Investments in unconsolidated affiliates, generally 50% or less owned partnerships and corporations, are accounted for by the equity method. These investments are primarily in energy projects. The difference between the carrying value of these equity investments and the underlying equity in the net assets amounted to $14 million at December 31, 2006. The differences are being amortized over the life of the energy projects. The following table presents summarized financial information of the investments in unconsolidated affiliates:

	2006	2005
	(in millions)	
Investments in Unconsolidated Affiliates		
Equity investment	$ 326	$ 365
Cost investment	13	14
Loans receivable	28	26
Total	$ 367	$ 405

At December 31, 2006 and 2005, EME has a 38% ownership interest in a small biomass project that it accounts for under the cost method of accounting as it does not have a significant influence over the project's operating and financial activities. It is not practicable to estimate the fair value of this project because of the absence of quoted market prices and the inability to estimate fair value without incurring excessive costs. However, EME believes that the carrying amount at December 31, 2006 and 2005 was not impaired. EME's subsidiaries have provided loans or advances related to certain projects. The loans receivable at December 31, 2006 and 2005 primarily consists of a $26 million, 5% interest promissory note, interest payable semiannually, due April 2008. The undistributed earnings of equity method investments were $43 million in 2006 and $62 million in 2005.

The following table presents summarized financial information of the remaining investments in unconsolidated affiliates accounted for by the equity method:

	Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Revenues	$ 1,574	$ 1,830	$ 1,617
Expenses	1,207	1,452	1,192
Net income	$ 367	$ 378	$ 425

	December 31, 2006	December 31, 2005
	(in millions)	
Current assets	$ 490	$ 665
Noncurrent assets	1,000	1,145
Total assets	$ 1,490	$ 1,810
Current liabilities	$ 330	$ 439
Noncurrent liabilities	572	644
Equity	588	727
Total liabilities and equity	$ 1,490	$ 1,810

The majority of noncurrent liabilities are comprised of project financing arrangements that are non-recourse to EME.

The following table presents, as of December 31, 2006, the investments in unconsolidated affiliates accounted for by the equity method that represent at least five percent (5%) of EME's income before tax or in which EME has an investment balance greater than $50 million.

Unconsolidated Affiliates	Location	Investment at December 31, 2006	Ownership Interest at December 31, 2006	Operating Status
		(in millions)		
Sunrise	Fellows, CA	$ 118	50%	Operating gas-fired facility
Watson	Carson, CA	74	49%	Operating cogeneration facility
Sycamore	Bakersfield, CA	48	50%	Operating cogeneration facility

Impairment Loss on Equity Method Investment

During the third quarter of 2005, EME fully impaired its equity investment in the March Point project following an updated forecast of future project cash flows. The March Point project is a 140 MW natural gas-fired cogeneration facility located in Anacortes, Washington, in which a subsidiary of EME owns a 50% partnership interest. The March Point project sells electricity to Puget Sound Energy, Inc. under two power purchase agreements that expire in 2011 and sells steam to Equilon Enterprises, LLC (a subsidiary of Shell Oil) under a steam supply agreement that also expires in 2011. March Point purchases a portion of its fuel requirements under long-term contracts with the remaining requirements purchased at current market prices. March Point's power sales agreements do not provide for a price adjustment related to the project's fuel costs. During the first nine months of 2005, long-term natural gas prices increased substantially, thereby adversely affecting the future cash flows of the March Point project. As a result, management concluded that its investment was impaired and recorded a $55 million charge during the third quarter of 2005.

Note 7. Property, Plant and Equipment

Property, plant and equipment consist of the following:

	December 31, 2006	December 31, 2005
	(in millions)	
Power plant facilities	$ 2,402	$ 2,334
Leasehold improvements	100	90
Emission allowances	1,305	1,305
Construction in progress	365	34
Equipment, furniture and fixtures	99	92
Capitalized leased equipment	1	1
	4,272	3,856
Less accumulated depreciation and amortization	981	844
Net property, plant and equipment	$ 3,291	$ 3,012

In connection with Midwest Generation's financing activities, EME has given first and second priority security interests in substantially all the coal-fired generating plants owned by Midwest Generation and the assets relating to those plants and receivables of EMMT directly related to Midwest Generation's hedging activities. The amount of assets pledged or mortgaged totaled approximately $2.9 billion at December 31, 2006. In addition to these assets, Midwest Generation's membership interests and the capital stock of Edison Mission Midwest Holdings were pledged. Emission allowances have not been pledged.

Asset Retirement Obligations

Effective January 1, 2003, EME adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires entities to record the fair value of a liability for an ARO in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased 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, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement.

In March 2005, the FASB issued FIN 47, "Accounting for Conditional Asset Retirement Obligations," an interpretation of SFAS No. 143. This interpretation clarifies that an entity is required to recognize a liability for the fair value of a conditional ARO if the fair value can be reasonably estimated even though uncertainty exists about the timing and/or method of settlement. This interpretation became effective as of December 31, 2005 for EME. EME identified conditional AROs related to asbestos removal and disposal costs at its owned Illinois Plants (buildings and power plant facilities) and retired structures leased at the Powerton Station. EME recorded a $1 million, after tax, charge as a cumulative effect adjustment for asbestos removal and disposal activities associated with retired Powerton structures that are currently scheduled for demolition in 2007. EME has not recorded a liability related to the owned structures because it cannot reasonably estimate fair value of the obligation at this time. The range of time over which EME may settle this obligation in the future (demolition or other method) is sufficiently large to not allow for the use of expected present value techniques.

EME recorded a liability representing expected future costs associated with site reclamations, facilities dismantlement and removal of environmental hazards as follows:

	2006	2005	2004
	(in millions)		
Beginning balance	$ 7	$ 5	$ 5
Cumulative effect of accounting change	—	2	—
Obligation incurred	1	—	—
Liabilities settled during the period	(1)	—	—
Accretion expense	1	—	—
Change in estimates	3	—	—
Ending balance	$ 11	$ 7	$ 5

The pro forma net income effect of adopting FIN 47 is not shown due to its immaterial impact on EME's results of operations. The pro forma liability for conditional AROs is not shown due to the immaterial impact on EME's consolidated balance sheet.

Note 8. Financial Instruments

Long-Term Obligations

Long-term obligations include both corporate debt and non-recourse project debt, whereby lenders rely on specific project assets to repay such obligations. At December 31, 2006, recourse debt to EME totaled $1.7 billion and non-recourse project debt totaled $1.5 billion. Long-term obligations consist of the following:

	December 31,	
	2006	2005
	(in millions)	
Recourse		
EME (parent only)		
Senior Notes, net		
due 2008 (10.0%)	$ —	$ 400
due 2009 (7.73%)	599	598
due 2011 (9.875%)	—	600
due 2013 (7.50%)	500	—
due 2016 (7.75%)	500	—
Obligations to Affiliates	78	78

	December 31,	
	2006	2005
	(in millions)	
Non-recourse		
Due to EME Funding Corp.—Long-Term Obligation due 2007-2008 (7.33%)	51	92
EME CP Holdings Co.		
Note Purchase Agreement due 2015 (7.31%)	76	79
Midwest Generation		
Second Priority Senior Secured Notes due 2034 (8.75%)	1,000	1,000
Credit Agreement due 2011 (LIBOR+1.50%) (6.94% at 12/31/06)	330	333
$500 million Credit Revolver due 2011 (LIBOR+1.50%)	—	170
Other	33	54
Subtotal	$ 3,167	$ 3,404
Less current maturities of long-term obligations	132	74
Total	$ 3,035	$ 3,330

Refinancing

Credit Agreement

On June 15, 2006, EME replaced its $98 million credit agreement with a new credit agreement that provides for a $500 million senior secured revolving loan and letter of credit facility and matures on June 15, 2012. Loans made under this credit facility bear interest, at EME's election, at either LIBOR (which is based on the interbank Eurodollar market) or the base rate (which is calculated as the higher of Citibank, N.A.'s publicly announced base rate and the federal funds rate in effect from time to time plus 0.50%) plus, in both cases, an applicable margin. The applicable margin depends on EME's debt ratings. As of December 31, 2006, EME had no borrowings and $27 million of letters of credit outstanding under this credit facility. The credit facility contains financial covenants which require EME to maintain a minimum interest coverage ratio and a maximum corporate debt to corporate capital ratio. A failure to meet a ratio threshold could trigger other provisions, such as mandatory prepayment provisions or restrictions on dividends. At December 31, 2006, EME met both these ratio tests.

As security for its obligations under this credit facility, EME pledged its ownership interests in the holding companies through which it owns its interests in the Illinois Plants, the Homer City facilities, the Westside projects and the Sunrise project. EME also granted a security interest in an account into which all distributions received by it from the Big 4 projects will be deposited. EME will be free to use these proceeds unless an event of default occurs under the credit facility.

Senior Notes

EME issued $500 million aggregate principal amount of its 7.50% senior notes due June 15, 2013 and $500 million aggregate principal amount of its 7.75% senior notes due June 15, 2016. EME will pay interest on the senior notes on June 15 and December 15 of each year, beginning on December 15, 2006. The senior notes are redeemable by EME at any time at a price equal to 100% of the principal amount of, plus accrued and unpaid interest and liquidated damages, if any, on, the senior notes plus a "make-whole" premium. The senior notes are EME's senior unsecured obligations, ranking equal in right of payment to all of EME's existing and future senior unsecured indebtedness, and will be senior to all of EME's future subordinated indebtedness. EME's secured debt and its other secured obligations are effectively senior to the senior notes to the extent of the value of the assets securing such debt or other obligations. None of EME's subsidiaries have guaranteed the senior notes and, as a result, all the existing and future liabilities of EME's subsidiaries are effectively senior to the senior notes.

EME used the net proceeds of the offering of the senior notes, together with cash on hand, to purchase its 10% senior notes due August 15, 2008 and its 9.875% senior notes due April 15, 2011. The net proceeds of the offering of the senior notes, together with cash on hand, were also used to pay related tender premiums, consent fees and accrued interest. EME recorded a $146 million loss on early extinguishment of debt during 2006.

Obligations to Affiliates

During 1997, EME declared a dividend of $78 million to The Mission Group (now known as Edison Mission Group Inc.) which was recorded as a note payable due in June 2007 with interest at LIBOR plus 0.275% (5.61% at December 31, 2006). The note was subsequently exchanged for two notes with the same terms and conditions and assigned to other subsidiaries of Edison International.

Annual Maturities on Long-Term Obligations

Annual maturities on long-term debt at December 31, 2006, for the next five years are summarized as follows: 2007—$132 million; 2008—$20 million; 2009—$615 million; 2010—$15 million; and 2011—$329 million.

Standby Letters of Credit

As of December 31, 2006, standby letters of credit aggregated to $34 million and were scheduled to expire in 2007.

Fair Values of Non-Derivative Financial Instruments

The carrying amount of cash and cash equivalents, trade accounts receivables and payables contained in EME's consolidated balance sheet approximates fair value. The following table summarizes the carrying amounts and fair values for outstanding non-derivative financial instruments (in millions):

	December 31, 2006		December 31, 2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Instruments				
Non-derivatives:				
Long-term obligations	$ 3,167	$ 3,494	$ 3,404	$ 3,744

In assessing the fair value of EME's financial instruments, EME uses a variety of methods and assumptions that are based on market conditions and risks existing at each balance sheet date. Quoted market prices for the same or similar instruments are used for long-term obligations.

Note 9. Risk Management and Derivative Financial Instruments

EME's risk management policy allows for the use of derivative financial instruments to limit financial exposure on EME's investments and to manage exposure from fluctuations in electricity, capacity and fuel prices, emission allowances, transmission rights, and interest rates for both trading and non-trading purposes.

Commodity Price Risk Management

EME's merchant operations expose it to commodity price risk, which represents the potential loss that can be caused by a change in the market value of a particular commodity. Commodity price risks are actively monitored by a risk management committee to ensure compliance with EME's risk management policies. Policies are in place which define risk management processes, and procedures exist which allow for monitoring of all commitments and positions with regular reviews by EME's risk management committee. Despite this, there can be no assurance that all risks have been accurately identified, measured and/or mitigated. EME uses "value at risk" to identify, measure, monitor and control its overall market risk exposure in respect of its Illinois Plants, its Homer City facilities, and its trading positions. The use of value at risk allows management to aggregate overall commodity risk, compare risk on a consistent basis and identify the risk factors. Value at risk measures the possible loss over a given time interval, under normal market conditions, at a given confidence level. Given the inherent limitations of value at risk and relying on a single risk measurement tool, EME supplements this approach with the use of stress testing and worst-case scenario analysis for key risk factors, as well as stop-loss limits and counterparty credit exposure limits.

In order to provide more predictable earnings and cash flow, EME may hedge a portion of the electric output of its merchant plants. When appropriate, EME manages the spread between the electric prices and fuel prices, and uses forward contracts, swaps, futures, or options contracts to achieve those objectives. There is no assurance that contracts to hedge changes in market prices will be effective.

Interest Rate Risk Management

Interest rate changes affect the cost of capital needed to operate EME's projects. EME mitigates the risk of interest rate fluctuations by arranging for fixed rate financing or variable rate financing with interest rate swaps, interest rate options or other hedging mechanisms for a number of EME's project financings.

Credit Risk

In conducting EME's hedging and trading activities, EME contracts with a number of utilities, energy companies, financial institutions, and other companies, collectively referred to as counterparties. In the event a counterparty were to default on its trade obligation, EME would be exposed to the risk of possible loss associated with re-contracting the product at a price different from the original contracted price if the non-performing counterparty were unable to pay the resulting liquidated damages owed to EME. Further, EME would be exposed to the risk of non-payment of accounts receivable accrued for products delivered prior to the time a counterparty defaulted.

To manage credit risk, EME looks at the risk of a potential default by counterparties. Credit risk is measured by the loss that would be incurred if counterparties failed to perform pursuant to the terms of their contractual obligations. EME measures, monitors and mitigates credit risk to the extent possible. To mitigate credit risk from counterparties, master netting agreements are used whenever possible and counterparties may be required to pledge collateral when deemed necessary. EME also takes other appropriate steps to limit or lower credit exposure. Processes have also been established to determine and monitor the creditworthiness of counterparties. EME manages the credit risk on the portfolio based on credit ratings using published ratings of counterparties and other publicly disclosed information, such as financial statements, regulatory filings, and press releases, to guide it in the process of setting credit levels, risk limits and contractual arrangements, including master netting agreements. A risk management committee regularly reviews the credit quality of EME's counterparties. Despite this, there can be no assurance that these efforts will be wholly successful in mitigating credit risk or that collateral pledged will be adequate.

EME's plants owned by unconsolidated affiliates in which EME owns an interest sell power under power purchase agreements. Generally, each plant sells its output to one counterparty. Accordingly, a default by a counterparty under a power purchase agreement, including a default as a result of a bankruptcy, would likely have a material adverse effect on the operations of such power plant.

In addition, coal for the Illinois Plants and the Homer City facilities is purchased from suppliers under contracts which may be for multiple years. A number of the coal suppliers to the Illinois Plants and the Homer City facilities do not currently have an investment grade credit rating and, accordingly, EME may have limited recourse to collect damages in the event of default by a supplier. EME seeks to mitigate this risk through diversification of its coal suppliers and through guarantees and other collateral arrangements when available. Despite this, there can be no assurance that these efforts will be successful in mitigating credit risk from coal suppliers.

EME's merchant plants sell electric power generally into the PJM market by participating in PJM's capacity and energy markets or transact capacity and energy on a bilateral basis. Sales into PJM accounted for approximately 58%, 69% and 23% of EME's consolidated operating revenues for the years ended December 31, 2006, 2005 and 2004, respectively. Moody's rates PJM's senior unsecured debt Aa3. PJM, an ISO with over 300 member companies, maintains its own credit risk policies and does not extend unsecured credit to non-investment grade companies. Any losses due to a PJM member default are shared by all other members based upon a predetermined formula. At December 31, 2006, EME's account receivable due from PJM was $57 million.

In 2004, EME also derived a significant source of its revenues from the sale of energy and capacity generated at the Illinois Plants to Exelon Generation primarily under three power purchase agreements. These power purchase agreements had all expired by the end of 2004. Exelon Generation accounted for 35% of EME's consolidated operating revenues for the year ended December 31, 2004.

For the year ended December 31, 2004, approximately 15% of EME's consolidated operating revenues generated at the Homer City facilities and Illinois Plants was from sales to BP Energy Company, a third-party customer.

Non-Trading Derivative Financial Instruments

The following table summarizes the fair values for outstanding derivative financial instruments used in EME's continuing operations for purposes other than trading by risk category (in millions):

	December 31, 2006		December 31, 2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Commodity price:				
Electricity	$ 184	$ 184	$ (434)	$ (434)

In assessing the fair value of EME's non-trading derivative financial instruments, EME uses a variety of methods and assumptions based on the market conditions and associated risks existing at each balance sheet date. The fair value of the commodity price contracts takes into account quoted market prices, time value of money, volatility of the underlying commodities and other factors.

EME classifies unrealized gains and losses from energy contracts as part of operating revenues. The following table summarizes unrealized gains (losses) from non-trading activities for the three-year period ended December 31, 2006:

	Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Non-qualifying hedges			
Illinois Plants	$ 28	$ (17)	$ (4)
Homer City	2	(1)	1
Ineffective portion of cash flow hedges			
Illinois Plants	2	(2)	—
Homer City	33	(40)	(14)
Total unrealized gains (losses)	$ 65	$ (60)	$ (17)

Energy Trading

EME engages in energy trading activities in markets where its merchant power plants are located. EME trades power, fuel and transmission using products available over the counter, through exchanges and from ISOs. Energy trading activity is limited by EME's risk management policies, including a limit on value at risk.

The carrying amounts and fair values of the commodity financial instruments related to energy trading activities as of December 31, 2006 and December 31, 2005, are set forth below (in millions):

	December 31, 2006		December 31, 2005	
	Assets	Liabilities	Assets	Liabilities
Electricity	$ 313	$ 207	$ 127	$ 27
Other	5	—	1	—
Electricity	$ 318	$ 207	$ 128	$ 27

Quoted market prices are used to determine the fair value of the financial instruments related to energy trading activities, except for the power sales agreement with an unaffiliated electric utility that EME's subsidiary purchased and restructured and a long-term power supply agreement with another unaffiliated party. EME's subsidiary recorded these agreements at fair value based upon a discounting of future electricity prices derived from a proprietary model using a discount rate equal to the cost of borrowing the non-recourse debt incurred to finance the purchase of the power supply agreement.

EME recorded net gains of approximately $137 million, $202 million and $29 million in 2006, 2005 and 2004, respectively, arising from energy trading activities reflected in operating revenues in EME's consolidated income statement. In accordance with Emerging Issues Task Force No. 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," EME netted 4.3 million MWh and 3.9 million MWh of sales and purchases of physically settled, gross purchases and sales during 2006 and 2005, respectively.

Note 10. Income Taxes

Current and Deferred Taxes

The provision (benefit) for income taxes is comprised of the following:

	Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Continuing Operations:			
Current			
Federal	$ 65	$ 231	$ (314)
State	16	39	(68)
Foreign	(1)	(1)	(1)
Total current	80	269	(383)
Deferred			
Federal	$ 87	$ (50)	$ (14)
State	22	(11)	(9)
Foreign	—	—	—
Total deferred	109	(61)	(23)
Provision (benefit) for income taxes from continuing operations	189	208	(406)
Discontinued operations	22	(40)	47
Change in accounting	—	(1)	—
Total	$ 211	$ 167	$ (359)

The components of income (loss) before income taxes and minority interest applicable to continuing operations, discontinued operations, and cumulative effect of change in accounting are as follows:

	Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Continuing Operations			
U.S.	$ 503	$ 614	$ (971)
Foreign	1	8	6
Total, continuing operations	504	622	(965)
Discontinued operations	120	(11)	788
Change in accounting	—	(2)	—
Total	$ 624	$ 609	$ (177)

Variations from the 35% federal statutory rate for income from continuing operations are as follows:

	Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Provision (benefit) for federal income taxes at statutory rate	$ 176	$ 218	$ (338)
Increase (decrease) in taxes from:			
State tax, net of federal benefit	23	20	(50)
Taxes on foreign operations at different rates	6	(4)	(3)
Resolution of IRS audit issue	—	(11)	—
Production tax credits	(12)	(8)	(7)
Other	(4)	(7)	(8)
Total provision (benefit) for income taxes from continuing operations	$ 189	$ 208	$ (406)
Effective tax (benefit) rate	37%	33%	(42)%

The components of the net accumulated deferred income tax liability are:

	December 31,	
	2006	2005
	(in millions)	
Deferred tax assets		
Accrued charges	$ 86	$ 126
Derivative assets	—	162
Deferred income	5	5
Total	91	293
Deferred tax liabilities		
Basis differences	$ 395	$ 353
Derivative liabilities	84	—
Tax credits, net	10	11
State taxes	3	—
Other	5	1
Total	497	365
Deferred tax liabilities and tax credits, net	$ 406	$ 72
Classification of accumulated deferred income taxes:		
Included in current assets	$ —	$ 155
Included in current liabilities	$ 59	$ —
Included in non-current liabilities	$ 347	$ 227

State loss carryforwards for various states totaled $4 million and $6 million at December 31, 2006 and 2005, respectively, with expiration dates beginning in 2022.

EME is, and may in the future be, under examination by tax authorities in varying tax jurisdictions with respect to positions it takes in connection with the filing of its tax returns. Matters raised upon audit may involve substantial amounts, which, if resolved unfavorably, an event not currently anticipated, could possibly be material. However, in EME's opinion, it is unlikely that the resolution of any such matters will have a material adverse effect upon EME's financial condition or results of operations.

Note 11. Compensation and Benefit Plans

Employee Savings Plan

A 401(k) plan is maintained to supplement eligible United States employees' retirement income. The plan received contributions from EME of $6 million each in 2006 and 2005 and $5 million in 2004.

Pension Plans and Postretirement Benefits Other than Pensions

SFAS No. 158 requires companies to recognize the overfunded or underfunded status of a defined benefit pension plan and other postretirement plans as assets or liabilities in their balance sheet; the assets or liabilities are offset through other comprehensive income (loss). See Note 1—Summary of Significant Accounting Policies—New Accounting Pronouncements for further discussion. EME adopted SFAS No. 158 prospectively on December 31, 2006.

Pension Plans

Noncontributory defined benefit pension plans (the non-union plan has a cash balance feature) cover most employees meeting minimum service requirements.

At December 31, 2005, the accumulated benefit obligations of the executive pension plans exceeded the related plan assets at the measurement dates. Prior to the adoption of SFAS No. 158, EME's consolidated balance sheets include an additional minimum liability, with corresponding charges to intangible assets and shareholders' equity (through a charge to accumulated other comprehensive income).

The expected contributions (all by the employer) are approximately $14 million for the year ended December 31, 2007. This amount is subject to change based on, among other things, the limits established for federal tax deductibility.

The fair value of plan assets is determined by market value.

Information on plan assets and benefit obligations is shown below:

	Years Ended December 31,	
	2006	**2005**
	(in millions)	
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	$ 159	$ 153
Service cost	16	16
Interest cost	9	8
Actuarial loss (gain)	3	(10)
Benefits paid	(6)	(8)
Intercompany transfers	3	—
Projected benefit obligation at end of year	$ 184	$ 159
Accumulated benefit obligation at end of year	$ 156	$ 137

	Years Ended December 31,	
	2006	2005
	(in millions)	
Change in plan assets		
Fair value of plan assets at beginning of year	$ 91	$ 77
Actual return on plan assets	15	9
Employer contributions	13	13
Benefits paid	(6)	(8)
Intercompany transfers	2	—
Fair value of plan assets at end of year	$ 115	$ 91
Determination of net recorded liability		
Funded status	$ (69)	$ (68)
Unrecognized net loss	—	14
Unrecognized prior service cost	—	1
Net recorded liability	$ (69)	$ (53)
Additional detail of amounts recognized in consolidated balance sheets:		
Intangible asset	$ —	$ 1
Accumulated other comprehensive loss	7	5
Additional detail of amounts recognized in accumulated other comprehensive loss:		
Prior service cost	$ 1	$ —
Net actuarial loss	6	—
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	$ 163	$ 159
Accumulated benefit obligation	142	137
Fair value of plan assets	100	91
Weighted-average assumptions at end of year:		
Discount rate	5.75%	5.50%
Rate of compensation increase	5.00%	5.00%

Expense components are:

	Years Ended December 31,		
	2006	2005	2004
Service cost	$ 16	$ 16	$ 16
Interest cost	9	8	7
Expected return on plan assets	(7)	(6)	(4)
Net amortization	1	1	1
Total expense	$ 19	$ 19	$ 20
Change in accumulated other comprehensive income (loss)	$ (2)	$ (3)	$ (2)

	Years Ended December 31,		
	2006	2005	2004
Weighted-average assumptions:			
Discount rate	5.50%	5.50%	6.00%
Rate of compensation increase	5.00%	5.00%	5.00%
Expected return on plan assets	7.50%	7.50%	7.50%

The estimated amortization amounts for 2007 are $0.1 million for prior service costs and $1 million for net actuarial loss.

The following benefit payments, which reflect expected future service, are expected to be paid:

Years Ending December 31,	(in millions)
2007	$ 6
2008	7
2009	8
2010	9
2011	11
2012-2016	78

Asset allocations are:

	Target for 2007	December 31, 2006	December 31, 2005
United States equity	45%	47%	47%
Non-United States equity	25%	26%	26%
Private equity	4%	2%	2%
Fixed income	26%	25%	25%

Postretirement Benefits Other Than Pensions

Most non-union employees retiring at or after age 55 with at least 10 years of service are eligible for postretirement health and dental care, life insurance and other benefits. Eligibility depends on a number of factors, including the employee's hire date.

On December 8, 2003, President Bush signed the Medicare Prescription Drug, Improvement and Modernization Act of 2003. The Act authorized a federal subsidy to be provided to plan sponsors for certain prescription drug benefits under Medicare. EME adopted a new accounting pronouncement for the effects of the Act, effective July 1, 2004, which reduced EME's accumulated benefits obligation by $3 million upon adoption.

The expected contributions (all by the employer) for the postretirement benefits other than pensions trust are $1 million for the year ended December 31, 2007. This amount is subject to change based on, among other things, the limits established for federal tax deductibility.

The fair value of plan assets is determined by market value.

Information on plan assets and benefit obligations is shown below:

	Years Ended December 31, 2006	2005
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 72	$ 58
Service cost	2	2
Interest cost	4	4
Actuarial loss (gain)	(3)	9
Benefits paid	(1)	(1)
Intercompany transfers	2	—
Benefit obligation at end of year	$ 76	$ 72
Change in plan assets		
Fair value of plan assets at beginning of year	$ —	$ —
Employer contributions	1	1
Benefits paid	(1)	(1)
Fair value of plan assets at end of year	$ —	$ —
Determination of net recorded liability		
Funded status	$ (76)	$ (72)
Unrecognized net loss	—	22
Unrecognized prior service cost	—	(10)
Net recorded liability	$ (76)	$ (60)
Additional details of amounts recognized in accumulated other comprehensive loss (income):		
Prior service cost	$ (9)	$ —
Net actuarial loss	17	—
Weighted-average assumptions at end of year:		
Discount rate	5.75%	5.50%
Assumed health care cost trend rates:		
Rate assumed for following year	9.25%	10.25%
Ultimate rate	5.00%	5.00%
Year ultimate rate reached	2011	2011

Expense components are:

	Years Ended December 31,		
	2006	2005	2004
	(in millions)		
Service cost	$ 2	$ 2	$ 2
Interest cost	4	4	3
Amortization of unrecognized prior service costs	(2)	(2)	(2)
Amortization of unrecognized net loss	1	2	1
Total expense	$ 5	$ 6	$ 4
Weighted-average assumptions:			
Discount rate	5.50%	5.75%	6.25%
Assumed health care cost trend rates:			
Current year	10.25%	10.00%	12.00%
Ultimate rate	5.00%	5.00%	5.00%
Year ultimate rate reached	2011	2010	2010

The estimated amortization amounts for 2007 are $(2) million for prior service cost (credit) and $1 million for net actuarial loss.

Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2006, by $13 million and annual aggregate service and interest costs by $1 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2006, by $11 million and annual aggregate service and interest costs by $1 million.

The following benefit payments are expected to be paid:

Years ended December 31,	Before Subsidy	Net
	(in millions)	
2007	$ 1	$ 1
2008	2	2
2009	2	2
2010	2	2
2011	3	3
2012-2016	23	22

Discount Rate

The discount rate enables EME to state expected future cash flows at a present value on the measurement date. EME selects its discount rate by performing a yield curve analysis. This analysis determines the equivalent discount rate on projected cash flows, matching the timing and amount of expected benefit payments. Three yield curves were considered: two corporate yield curves (Citigroup and AON) and a curve based on treasury rates (plus 90 basis points). EME also compared the yield curve analysis against the Moody's AA Corporate bond rate.

Description of Pension and Postretirement Benefits Other Than Pensions Investment Strategies

The investment of plan assets is overseen by a fiduciary investment committee. Plan assets are invested using a combination of asset classes, and may have active and passive investment strategies within asset classes. EME employs multiple investment management firms. Investment managers within each asset class cover a range of investment styles and approaches. Risk is controlled through diversification among multiple asset classes, managers, styles, and securities. Plan, asset class and individual manager performance is measured against targets. EME also monitors the stability of its investments managers' organizations.

Allowable investment types include:

- *United States Equity:* Common and preferred stocks of large, medium, and small companies which are predominantly United States-based.
- *Non-United States Equity:* Equity securities issued by companies domiciled outside the United States and in depository receipts which represent ownership of securities of non-United States companies.
- *Private Equity:* Limited partnerships that invest in non-publicly traded entities.
- *Fixed Income:* Fixed income securities issued or guaranteed by the United States government, non-United States governments, government agencies and instrumentalities, mortgage backed securities and corporate debt obligations. A small portion of the fixed income position may be held in debt securities that are below investment grade.

Permitted ranges around asset class portfolio weights are plus or minus 5%. Where approved by the fiduciary investment committee, futures contracts are used for portfolio rebalancing and to approach fully invested portfolio positions. Where authorized, a few of the plans' investment managers employ limited use of derivatives, including futures contracts, options, options on futures and interest rate swaps in place of direct investment in securities to gain efficient exposure to markets. Derivatives are not used to leverage the plans or any portfolios.

Determination of the Expected Long-Term Rate of Return on Assets for United States Plans

The overall expected long-term rate of return on assets assumption is based on the target asset allocation for plan assets and capital markets return forecasts for asset classes employed. A portion of postretirement benefits other than pensions trust asset returns are subject to taxation, so the expected long-term rate of return for these assets is determined on an after-tax basis.

Capital Markets Return Forecasts

The estimated total return for fixed income is based on an equilibrium yield for intermediate United States government bonds plus a premium for exposure to non-government bonds in the broad fixed income market. The equilibrium yield is based on analysis of historic data and is consistent with experience over various economic environments. The premium of the broad market over United States government bonds is a historic average premium. The estimated rate of return for equity is estimated to be a 3% premium over the estimated total return of intermediate United States government bonds. This value is determined by combining estimates of real earnings growth, dividend yields and inflation, each of which was determined using historical analysis. The rate of return for private equity is estimated to be a 5% premium over public equity, reflecting a premium for higher volatility and illiquidity.

Stock-Based Compensation

Stock Options

Under various plans, EME may grant stock options at exercise prices equal to the average of the high and low price at the grant date and other awards related to or with a value derived from its common stock to directors and certain employees. Options generally expire 10 years after the grant date and vest over a period of four years of continuous service, with expense recognized evenly over the requisite service period, except for awards granted to retirement-eligible participants, as discussed in Note 1—Stock-Based Compensation. Stock-based compensation associated with stock options was $8 million 2006. Under prior accounting rules, there was no comparable expense recognized for the same period in 2005 and 2004. See Note 1—Stock-Based Compensation for further discussion.

Beginning with awards made in 2003, stock options accrue dividend equivalents for the first five years of the option term. Unless transferred to nonqualified deferral plan accounts, dividend equivalents accumulate without interest. Dividend equivalents are paid only on options that vest, including options that are unexercised. Dividend equivalents are paid in cash after the vesting date. Edison International has discretion to pay certain dividend equivalents in shares of Edison International common stock. Additionally, Edison International will substitute cash awards to the extent necessary to pay tax withholding or any government levies.

The fair value for each option granted was determined as of the date of grant date using the Black-Scholes option-pricing model. The Black-Scholes option-pricing model requires various assumptions noted in the following table.

Years ended December 31,	2006	2005	2004
Expected terms (in years)	9-10	9-10	9-10
Risk-free interest rate	4.3% to 4.7%	4.1% to 4.3%	4.0% to 4.3%
Expected dividend yield	2.3% to 2.8%	2.1% to 3.1%	2.7% to 3.7%
Weighted-average expected dividend yield	2.4%	3.1%	3.6%
Expected volatility	16% to 17%	15% to 20%	19% to 22%
Weighted-average volatility	16.3%	19.5%	21.5%

The expected term of options granted is based on the actual remaining contractual term of the options. The risk-free interest rate for periods within the contractual life of the option is based on a 52-week historical average of the 10-year semi-annual coupon U.S. Treasury note. In 2006, expected volatility is based on the historical volatility of Edison international's common stock for the recent 36 months. Prior to January 1, 2006, expected volatility was based on the median of the most recent 36 months historical volatility of peer companies because Edison International's historical volatility was impacted by the California energy crisis.

A summary of the status of Edison International's stock options granted to EME employees is as follows:

		Weighted-Average		
	Stock Options	Exercise Price	Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding, December 31, 2005	3,626,365	$ 22.06		
Granted	406,214	$ 44.17		
Transferred to affiliates	(298,647)	$ 21.83		
Forfeited	(41,559)	$ 29.83		
Exercised	(678,228)	$ 19.54		
Outstanding, December 31, 2006	3,014,145	$ 25.52		
Vested and expected to vest at December 31, 2006	2,883,351	$ 25.27	6.71	$ 55,115,262
Exercisable at December 31, 2006	1,391,462	$ 20.25	5.60	$ 33,582,935

The weighted-average grant-date fair value of options granted during 2006, 2005 and 2004 was $14.44, $11.74 and $8.26, respectively. The total intrinsic value of options exercised during 2006, 2005 and 2004 was $18 million, $18 million and $8 million, respectively. At December 31, 2006, there was $8 million of total unrecognized compensation cost related to stock options, net of expected forfeitures. That cost is expected to be recognized over a weighted-average period of approximately two years. The fair value of options vested during 2006, 2005 and 2004 was $8 million, $5 million and $3 million, respectively.

The amount of cash used by Edison International to settle stock options exercised by EME employees was $33 million, $31 million and $19 million for 2006, 2005 and 2004, respectively. Cash received by Edison International from options exercised by EME employees for 2006, 2005 and 2004 was $15 million, $14 million and $10 million, respectively. The estimated tax benefit from options exercised for 2006, 2005 and 2004 was $7 million, $7 million and $3 million, respectively.

Performance Shares

A target number of contingent performance shares were awarded to executives in January 2004, January 2005 and March 2006, and vest at the end of December 2006, 2007 and 2008, respectively. Dividend equivalents associated with these performance shares accumulate without interest and will be payable in cash following the end of the performance period when the performance shares are paid, although Edison International has discretion to pay certain dividend equivalents in Edison International common stock. The vesting of Edison International's performance shares is dependent upon a market condition and three years of continuous service subject to a prorated adjustment for employees who are terminated under certain circumstances or retire, but payment cannot be accelerated. The market condition is based on Edison International's common stock performance relative to the performance of a specified group of companies at the end of a three-calendar-year period. The number of performance shares earned is determined based on Edison International's ranking among these companies. Dividend equivalents will be adjusted to correlate to the actual number of performance shares paid. Performance shares earned are settled half in cash and half in common stock; however, Edison International has discretion under certain of the awards to pay the half subject to cash settlement in common stock. Additionally, cash awards are substituted to the extent necessary to pay tax withholding or any government levies. The portion of performance shares settled in cash is classified as a share-based liability award. The fair value of these shares is remeasured at each reporting period and the related compensation expense is adjusted. The portion of performance shares payable in common stock is classified as a share-based equity award. Compensation expense related to these shares is based on the grant-date fair value. Performance shares expense is recognized ratably over the requisite service period based on the fair values determined, except for awards granted to retirement-eligible participants, as discussed in Note 1—Stock-Based Compensation. Stock-based compensation associated with performance shares was $3 million, $15 million and $16 million for 2006, 2005 and 2004, respectively. The amount of cash used to settle performance shares classified as equity awards was $10 million, $4 million and $5 million for 2006, 2005 and 2004, respectively.

The performance shares' fair value is determined using a Monte Carlo simulation valuation model. The Monte Carlo simulation valuation model requires a risk-free interest rate and an expected volatility rate assumption. The risk-free interest rate is based on a 52-week historical average of the three-year semi-annual coupon U.S. Treasury note and is used as proxy for the expected return for the specified group of companies. Volatility is based on the historical volatility of Edison International's common stock for the recent 36 months. Historical volatility for each company in the specified group is obtained from a financial data services provider.

Edison International's risk-free interest rate used to determine the grant date fair values for the 2006, 2005 and 2004 performance shares classified as share-based equity awards was 4.1%, 2.7% and 2.1%, respectively. Edison International's expected volatility used to determine the grant date fair values for the 2006, 2005 and 2004 performance shares classified as share-based equity awards was 16.2%, 27.7% and 36.0%, respectively. The portion of performance shares classified as share-based liability awards are revalued at each reporting period. The risk-free interest rate and expected volatility rate used to determine the fair value as of December 31, 2006 was 4.8% and 16.5%, respectively.

The total intrinsic value of performance shares settled during 2006, 2005 and 2004 was $19 million, $8 million and $2 million, respectively, which included cash paid to settle the performance shares classified as liability awards for 2006, 2005 and 2004 of $8 million, $4 million and $1 million, respectively. At December 31, 2006, there was $1 million (based on the December 31, 2006 fair value of performance shares classified as liability awards) of total unrecognized compensation cost related to performance shares. That cost is expected to be recognized over a weighted-average period of less than two years. The fair value of performance shares vested during 2006, 2005 and 2004 was $7 million, $11 million and $6 million, respectively.

A summary of the status of Edison International nonvested performance shares granted to EME employees and classified as equity awards is as follows:

	Performance Shares	Weighted-Average Grant-Date Fair Value
Nonvested at December 31, 2005	67,530	$ 38.63
Granted	16,121	52.86
Forfeited	(1,266)	39.36
Paid out	(39,704)	33.62
Nonvested at December 31, 2006	42,681	$ 48.65

The weighted-average grant-date fair value of performance shares classified as equity awards granted during 2005 and 2004 was $46.09 and $33.62, respectively.

A summary of the status of Edison International nonvested performance shares granted to EME employees and classified as liability awards (the current portion is reflected in the caption "Accrued liabilities" and the long-term portion is reflected in "Other long-term liabilities" on the consolidated balance sheets) is as follows:

	Performance Shares	Weighted-Average Fair Value
Nonvested at December 31, 2005	67,547	
Granted	16,139	
Forfeited	(1,267)	
Paid out	(39,710)	
Nonvested at December 31, 2006	42,709	$ 50.96

Note 12. Commitments and Contingencies

Lease Commitments

EME leases office space, property and equipment under noncancelable lease agreements that expire in various years through 2030.

Future minimum payments for operating leases at December 31, 2006 are:

Years Ending December 31,	Operating Leases
	(in millions)
2007	$ 360
2008	359
2009	354
2010	340
2011	324
Thereafter	2,670
Total future commitments	$ 4,407

The minimum commitments do not include contingent rentals with respect to the wind projects which may be paid under certain leases on the basis of a percentage of sales calculation if this is in excess of the stipulated minimum amount.

Operating lease expense amounted to $201 million in both 2006 and 2005 and $210 million in 2004.

Sale-Leaseback Transactions

On December 7, 2001, a subsidiary of EME completed a sale-leaseback of EME's Homer City facilities to third-party lessors for an aggregate purchase price of $1.6 billion, consisting of $782 million in cash and assumption of debt (the fair value of which was $809 million). Under the terms of the 33.67-year leases, EME's subsidiary is obligated to make semi-annual lease payments on each April 1 and October 1. If a lessor intends to sell its interest in the Homer City facilities, EME has a right of first refusal to acquire the interest at fair market value. Minimum lease payments (included in the table above) are $151 million in 2007, $152 million in 2008, $151 million in 2009, $155 million in 2010, and

$160 million in 2011, and the total remaining minimum lease payments are $1.8 billion. The gain on the sale of the facilities has been deferred and is being amortized over the term of the leases.

On August 24, 2000, a subsidiary of EME completed a sale-leaseback of EME's Powerton and Joliet power facilities located in Illinois to third-party lessors for an aggregate purchase price of $1.4 billion. Under the terms of the leases (33.75 years for Powerton and 30 years for Joliet), EME's subsidiary makes semi-annual lease payments on each January 2 and July 2, which began January 2, 2001. EME guarantees its subsidiary's payments under the leases. If a lessor intends to sell its interest in the Powerton or Joliet power facility, EME has a right of first refusal to acquire the interest at fair market value. Minimum lease payments (included in the table above) are $185 million each year in 2007 through 2009, $170 million in 2010, and $151 million in 2011, and the total remaining minimum lease payments are $790 million. The gain on the sale of the power facilities has been deferred and is being amortized over the term of the leases.

Other Commitments

Capital Improvements

At December 31, 2006, EME's subsidiaries had firm commitments to spend approximately $186 million in 2007 on capital and construction expenditures. The majority of these expenditures relate to the construction of the 161 MW Wildorado wind project and four other wind projects totaling 181 MW. Also included are expenditures for dust collection and mitigation system and various other smaller projects. These expenditures are planned to be financed by cash on hand, cash generated from operations or existing subsidiary credit agreements.

Fuel Supply Contracts

At December 31, 2006, Midwest Generation and EME Homer City had fuel purchase commitments with various third-party suppliers. The remaining contracts' lengths range from less than one year to six years. Based on the contract provisions, which consist of fixed prices, subject to adjustment clauses, these minimum commitments are currently estimated to aggregate $675 million in the next five years summarized as follows: 2007—$365 million; 2008—$150 million; 2009—$89 million; 2010—$62 million; and 2011—$9 million.

In February 2007, Midwest Generation contracted for the purchase of additional coal in the amount of 9 million tons for 2008, 6 million tons for 2009 and 6 million tons for 2010.

Gas Transportation Agreements

At December 31, 2006, EME had a contractual commitment to transport natural gas. EME's share of the commitment to pay minimum fees under its gas transportation agreement, which has a remaining contract length of 11 years, is currently estimated to aggregate $40 million in the next five years, $8 million each year, 2007 through 2011.

Coal Transportation Agreements

At December 31, 2006, EME's subsidiaries had contractual commitments for the transport of coal to their respective facilities, with remaining contract lengths that range from one year to five years. Midwest Generation's primary contract is with Union Pacific Railroad (and various delivering carriers) which extends through 2011. Midwest Generation commitments under this agreement are based on actual coal purchases from the PRB. Accordingly, Midwest Generation's contractual obligations for transportation are based on coal volumes set forth in their fuel supply contracts. EME Homer City commitments under its agreements are based on the contract provisions, which consist of fixed prices, subject to adjustment clauses. Although trucking remains the predominant mode of transportation for coal shipments to the Homer City facilities, rail transportation is expected to increase in 2007 as EME Homer City diversifies its alternative modes of transporting coal to the plant site. Based on the committed coal volumes in the fuel supply contracts described above, these minimum commitments are currently estimated to aggregate $455 million in the next four years, summarized as follows: 2007—$220 million; 2008—$84 million; 2009—$75 million; and 2010—$76 million.

Other Contractual Obligations

At December 31, 2006, Midwest Generation was party to a long-term power purchase contract with Calumet Energy Team LLC entered into as part of the settlement agreement with Commonwealth Edison, which terminated Midwest Generation's obligation to build additional gas-fired generation in the Chicago area. The contract requires Midwest Generation to pay a monthly capacity payment and gives Midwest Generation an option to purchase energy from Calumet Energy Team at prices based primarily on operations and maintenance and fuel costs. These minimum commitments are currently estimated to aggregate $17 million in the next five years: $4 million each year, 2007 to 2010, and $0.4 million in 2011.

Turbine Commitments

At December 31, 2006, EME had entered into agreements with vendors securing 255 wind turbines (487 MW) with remaining commitments of $387 million in 2007 and $23 million in 2008. In addition, EME had entered into an agreement for the purchase of five gas turbines and related equipment for an aggregate purchase price of approximately $140 million with remaining commitments of $76 million in 2007 and $3 million in 2008. In February 2007, EME was advised that it was an unsuccessful bidder in the request for offers conducted by SCE for the supply of generation capacity. EME plans to use the turbines which it had purchased and reserved for this bid for other generation supply opportunities.

Guarantees and Indemnities

EME and certain of its subsidiaries have various financial and performance guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts include performance guarantees, guarantees of debt and indemnifications.

Tax Indemnity Agreements

In connection with the sale-leaseback transactions that EME has entered into related to the Powerton and Joliet Stations in Illinois, the Collins Station in Illinois, and the Homer City facilities in Pennsylvania, EME and several of its subsidiaries entered into tax indemnity agreements. Under these tax indemnity agreements, these entities agreed to indemnify the lessors in the sale-leaseback transactions for specified adverse tax consequences that could result in certain situations set forth in each tax indemnity agreement, including specified defaults under the respective leases. The potential indemnity obligations under these tax indemnity agreements could be significant. Due to the nature of these potential obligations, EME cannot determine a maximum potential liability which would be triggered by a valid claim from the lessors. EME has not recorded a liability related to these indemnities. In connection with the termination of the Collins Station lease in April 2004, Midwest Generation will continue to have obligations under the tax indemnity agreement with the former lease equity investor. For more information about the termination of the Collins Station lease, see Note 2—Restructuring, Loss on Lease Termination, Asset Impairment and Other Charges.

Indemnities Provided as Part of the Acquisition of the Illinois Plants

In connection with the acquisition of the Illinois Plants, EME agreed to indemnify Commonwealth Edison with respect to specified environmental liabilities before and after December 15, 1999, the date of sale. The indemnification claims are reduced by any insurance proceeds and tax benefits related to such claims and are subject to a requirement that Commonwealth Edison take all reasonable steps to mitigate losses related to any such indemnification claim. Due to the nature of the obligation under this indemnity, a maximum potential liability cannot be determined. This indemnification for environmental liabilities is not limited in term and would be triggered by a valid claim from Commonwealth Edison. Except as discussed below, EME has not recorded a liability related to this indemnity.

Midwest Generation entered into a supplemental agreement with Commonwealth Edison and Exelon Generation on February 20, 2003 to resolve a dispute regarding interpretation of its reimbursement obligation for asbestos claims under the environmental indemnities set forth in the Asset Sale Agreement. Under this supplemental agreement, Midwest Generation agreed to reimburse Commonwealth Edison and Exelon Generation for 50% of specific asbestos claims pending as of February 2003 and related expenses less recovery of insurance costs, and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement. As a general matter, Commonwealth Edison and Midwest Generation apportion responsibility for future asbestos-related claims based upon the number of exposure sites that are Commonwealth Edison locations or Midwest Generation locations. The obligations under this agreement are not subject to a maximum liability. The supplemental agreement has a five-year term with an automatic renewal provision (subject to the right of either party to terminate). Payments are made under this indemnity upon tender by Commonwealth Edison of appropriate proof of liability for an asbestos-related settlement, judgment, verdict, or expense. There were approximately 186 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed at December 31, 2006. Midwest Generation had recorded a $65 million and $67 million liability at December 31, 2006 and 2005, respectively, related to this matter.

The amounts recorded by Midwest Generation for the asbestos-related liability are based upon a number of assumptions. Future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding asbestos litigation in the United States, could cause the actual costs to be higher or lower than projected.

Indemnity Provided as Part of the Acquisition of the Homer City Facilities

In connection with the acquisition of the Homer City facilities, EME Homer City agreed to indemnify the sellers with respect to specific environmental liabilities before and after the date of sale. Payments would be triggered under this indemnity by a claim from the sellers. EME guaranteed the obligations of EME Homer City. Due to the nature of the obligation under this indemnity provision, it is not subject to a maximum potential liability and does not have an expiration date. EME has not recorded a liability related to this indemnity.

Indemnities Provided under Asset Sale Agreements

The asset sale agreements for the sale of EME's international assets contain indemnities from EME to the purchasers, including indemnification for taxes imposed with respect to operations of the assets prior to the sale and for pre-closing environmental liabilities. Not all indemnities under the asset sale agreements have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. At December 31, 2006 and 2005, EME had recorded a liability of $95 million and $122 million, respectively, related to these matters.

In connection with the sale of various domestic assets, EME has from time to time provided indemnities to the purchasers for taxes imposed with respect to operations of the asset prior to the sale. EME has also provided indemnities to purchasers for items specified in each agreement (for example, specific pre-existing litigation matters and/or environmental conditions). Due to the nature of the obligations under these indemnity agreements, a maximum potential liability cannot be determined. Not all indemnities under the asset sale agreements have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. EME has not recorded a liability related to these indemnities.

Capacity Indemnification Agreements

EME has guaranteed, jointly and severally with Texaco Inc., the obligations of March Point Cogeneration Company under its project power sales agreements to repay capacity payments to the project's power purchaser in the event that the power sales agreements terminate, March Point Cogeneration Company abandons the project, or the project fails to return to normal operations within a reasonable time after a complete or partial shutdown, during the term of the power sales agreements. In addition, a subsidiary of EME has guaranteed the obligations of Sycamore Cogeneration Company under its project power sales agreement to repay capacity payments to the project's power purchaser in the event that the project unilaterally terminates its performance or reduces its electric power producing capability during the term of the power sales agreement. The obligations under the indemnification agreements as of December 31, 2006, if payment were required, would be $101 million. EME has not recorded a liability related to these indemnities.

Subsidiary Guarantee for Performance of Unconsolidated Affiliate

A subsidiary of EME has guaranteed the obligations of an unconsolidated affiliate to make payments to a third party for power delivered under a fixed-price power sales agreement that expires in August 2007. EME believes there is sufficient cash flow to pay the power suppliers, assuming timely payment by the power purchasers. Due to the nature of this indemnity, a maximum potential liability cannot be determined. To the extent EME's subsidiary would be required to make payments under the guarantee, EME's subsidiary and EME are indemnified by Peabody Energy Corporation pursuant to the 2000 Purchase and Sale Agreement for Citizens Power LLC. EME's subsidiary has not recorded a liability related to this indemnity.

Contingencies

FERC Notice Regarding Investigatory Proceeding against EMMT

At the end of October 2006, EMMT was advised by the enforcement staff at the FERC that it is prepared to recommend that the FERC initiate a formal investigatory proceeding and seek monetary sanctions against EMMT for alleged violation of the FERC's rules with respect to certain bidding practices employed by EMMT. EMMT is engaged in discussions with the staff to explore the possibility of resolution of this matter. Should a formal proceeding be commenced, EMMT will be entitled to contest any alleged violations before the FERC and an appropriate court. EME believes that EMMT has complied with the FERC's rules and intends to contest vigorously any allegation of violation. EME cannot predict at this time the outcome of this matter or estimate the possible liability should the outcome be adverse.

Midway-Sunset Cogeneration Company

San Joaquin Energy Company, a wholly owned subsidiary of EME, owns a 50% general partnership interest in Midway-Sunset Cogeneration Company, which owns a 225 MW cogeneration facility near

Fellows, California. Midway-Sunset is a party to several proceedings pending at the FERC involving claims for refunds from entities that sold power and related services into the California markets operated by the California Power Exchange and the California Independent System Operator (collectively the California Markets) at prices that were allegedly not just and reasonable, as required by the Federal Power Act.

Midway-Sunset is a party to these proceedings because Midway-Sunset was a seller in the California Markets during 2000 and 2001, both for its own account and on behalf of SCE and PG&E, the utilities to which the majority of Midway-Sunset's power was contracted for sale. As a seller into the California Markets, Midway-Sunset is potentially liable for refunds to purchasers in these markets.

The claims asserted against Midway-Sunset for refunds related to power sold into the California Markets, including power sold on behalf of SCE and PG&E, are estimated to be less than $70 million for all periods under consideration. Midway-Sunset has calculated its potential liability for refunds related to power sold into the California Markets on its own behalf (excluding power sold on behalf of SCE and PG&E) to be approximately $0.5 million for the period October 2, 2000 through June 20, 2001. Midway Sunset's potential liability for sales on its own behalf during the period May 1, 2000 through October 1, 2000 has not yet been calculated but is not expected to be material. These calculations were made in accordance with the methodology approved by the FERC, but it is possible that this methodology will be challenged.

Because Midway-Sunset did not retain any proceeds from power sold into the California Markets on behalf of SCE and PG&E in excess of the amounts to which it was entitled under the pre-existing power sales contracts, but instead passed those proceeds on to the utilities, EME believes that PG&E and SCE are obligated to reimburse Midway-Sunset for any refund liability that it incurs as a result of sales made into the California Markets on their behalf. Midway-Sunset intends vigorously to assert these positions. However, at this time EME cannot predict the outcome of this matter.

Insurance

On January 29, 2006, the main power transformer on Unit 3 of the Homer City facilities failed, resulting in a suspension of operations at this unit. EME Homer City secured a replacement transformer and Unit 3 returned to service on May 5, 2006. The main transformer failure resulted in claims under EME Homer City's property and business interruption insurance policies. At December 31, 2006, EME Homer City had a $17 million receivable, of which $11 million relates to business interruption insurance coverage and has been reflected in other income (expense), net in EME's consolidated income statements. In January 2007, EME Homer City received a $3.5 million cash payment related to the replacement transformer.

Litigation

EME experiences other routine litigation in the normal course of its business. None of such pending routine litigation is expected to have a material adverse effect on EME's consolidated financial position or results of operations.

Environmental Matters and Regulations

Introduction

The construction and operation of power plants are subject to environmental regulation by federal, state and local authorities. EME believes that it is in substantial compliance with existing environmental regulatory requirements. Typically, environmental laws and regulations require a lengthy and complex process for obtaining licenses, permits and approvals prior to construction, operation or modification of a project or generating facility. Meeting all the necessary requirements can delay or sometimes prevent the completion of a proposed project, as well as require extensive modifications to existing projects, which may involve significant capital expenditures. If EME fails to comply with applicable environmental laws, it may be subject to injunctive relief or penalties and fines imposed by regulatory authorities.

Air Quality Regulation

Federal environmental regulations require reductions in emissions beginning in 2009 and require states to adopt implementation plans that are equal to or more stringent than the federal requirements. Compliance with these regulations and SIPs will affect the costs and the manner in which EME conducts its business, and will require EME to make substantial additional capital expenditures. There is no assurance that EME would be able to recover these increased costs from its customers or that EME's financial position and results of operations would not be materially adversely affected as a result.

Clean Air Act

On May 12, 2005, the CAIR was published in the Federal Register. The CAIR requires 28 eastern states and the District of Columbia to address ozone attainment issues by reducing regional NO_x and SO_2 emissions. The CAIR reduces the current Clean Air Act Title IV Phase II SO_2 emissions allowance cap for 2010 and 2015 by 50% and 65%, respectively. The CAIR also requires reductions in regional NO_x emissions in 2009 and 2015 by 53% and 61%, respectively, from 2003 levels. The CAIR has been challenged in court, which may result in changes to the substance of the rule and to the timetables for implementation.

EME expects that compliance with the CAIR and the regulations and revised SIPs developed as a consequence of the CAIR will result in increased capital expenditures and operating expenses. EME's approach to meeting these obligations will consist of a blending of capital expenditure and emission allowance purchases that will be based on an ongoing assessment of the dynamics of its market conditions.

Illinois—

On December 11, 2006, Midwest Generation entered into an agreement with the Illinois EPA to reduce mercury, NO_x and SO_2 emissions at the Illinois Plants. The agreement has been embodied in rule language, called the CPS, and Midwest Generation's obligations under the agreement are conditioned upon the formal adoption of the CPS as an Illinois rule. On January 5, 2007, the Illinois EPA and Midwest Generation jointly filed the CPS in the pending state rulemaking related to the Illinois SIP for the CAIR. Midwest Generation expects the CPS to become final in the spring of 2007 and believes that, upon adoption, the CPS will provide greater predictability of the timing and amount of emissions reductions which will be required of the Illinois Plants for these pollutants through 2018. No assurance can be given that all required regulatory approvals will be received, and if not received, Midwest Generation will remain subject to existing and future requirements as to emissions of these pollutants.

If the agreement is implemented as contemplated, Midwest Generation will be required to achieve specified emissions reductions through a combination of environmental retrofits or unit shutdowns. The agreement contemplates three phases with each phase relating to one of the pollutants involved. Capital expenditures will be required for each phase.

The first phase involves installing activated carbon injection technology in 2008 and 2009 for the removal of mercury, a technology which EME has been testing at some of its plants. Capital expenditures relating to these controls are currently estimated to be approximately $60 million.

The second phase requires the installation of additional controls by the end of 2011 to further reduce NO_x emissions from units to be determined by Midwest Generation in order to achieve an agreed-on fleetwide level of NO_x emissions per million Btu. Capital expenditures for these controls are currently estimated to be approximately $450 million.

Thereafter, during the third phase of the plan, the focus will be on the reduction of SO_2 emissions. Midwest Generation will be required either to place controls on several units at the Illinois Plants between 2012 and 2018 for this purpose or to remove them from service. Midwest Generation will consider many factors in making this choice including, among others, an assessment of the cost and performance of environmental technologies and equipment, the remaining estimated useful life of each affected unit and the market outlook for the prices of various commodities including electrical energy and capacity, coal and natural gas. In view of the many factors involved, Midwest Generation has not yet determined what actions it may take at each affected unit to provide for optimal compliance with the agreement during its third phase. At this time, however, additional capital expenditures during the third phase of the plan are estimated as being in the range of approximately $2.2 billion to $2.9 billion, depending on the number of units on which controls are placed versus the number which are removed from service. For the reasons described above, actual capital expenditures may vary substantially from the above estimates.

On May 30, 2006, the Illinois EPA submitted a proposed regulation to the Illinois Pollution Control Board to implement the Illinois SIP required for compliance with the CAIR. The Illinois Pollution Control Board held hearings on this SIP on October 10, 2006 and November 28, 2006. As noted previously, on January 5, 2007 the Illinois EPA and Midwest Generation filed the CPS in the pending Illinois rulemaking.

Pennsylvania—

The Pennsylvania Environmental Quality Board accepted the PADEP's proposed SIP to implement the CAIR on February 20, 2007. The SIP is very similar to the Federal CAIR with modest NOx set asides for generation from renewables and waste coal. At this time EME plans to comply with the proposal using existing pollution control equipment supplemented with the purchase of SO_2 credits for the first phase of the rule which is effective in 2010.

Mercury Regulation

The CAMR, published in the Federal Register on May 18, 2005, creates a market-based cap-and-trade program to reduce nationwide utility emissions of mercury in two distinct phases. In the first phase of the program, which will come into effect in 2010, the annual nationwide cap will be 38 tons. Emissions of mercury are to be reduced primarily by taking advantage of mercury reductions achieved by reducing SO_2 and NO_x emissions under the CAIR. In the second phase, which is to take effect in 2018, coal-fired power plants will be subject to a lower annual cap, which will reduce emissions nationwide to 15 tons. States may join the trading program by adopting the CAMR model trading rule in state regulations, or they may adopt regulations that mirror the necessary components of the model trading rule. States are not required to adopt a cap-and-trade program and may promulgate alternative regulations, such as command and control regulations, that are equivalent to or more stringent than the CAMR's suggested cap-and-trade program. Any program adopted by a state must be approved by the US EPA.

Contemporaneous with the adoption of the CAMR, the US EPA rescinded its previous finding that mercury emissions from coal-fired power plants had to be regulated as a hazardous air pollutant pursuant to Section 112 of the federal Clean Air Act, which would have imposed technology-based standards. Both the US EPA's rescission action and the CAMR are being challenged in the courts. Because EME cannot predict the outcome of these challenges, which could result in changes to the CAMR rules and timetables, the full impact of this regulation currently cannot be assessed.

Illinois—

The final state rule for the reduction of mercury emissions in Illinois was adopted and became effective on December 21, 2006. The rule requires a 90% reduction of mercury emissions from coal-fired power plants averaged across company-owned Illinois stations and a minimum reduction of 75% for individual generating sources by July 1, 2009. The rule requires each station to achieve a 90% reduction by January 1, 2014 and, because emissions are measured on a rolling 12-month average, stations must install equipment necessary to meet the January 1, 2014, 90% reduction by January 1, 2013. Buying or selling of emission allowances under the federal CAMR cap and trade program would be prohibited.

Midwest Generation's pending CPS, if adopted, will supersede this rule for the Illinois Plants. The CPS requires installation of activated carbon injection technology for the removal of mercury on all Midwest Generation units by July 2009 (except for three units to be shut down by the end of 2010), prohibits participation in the federal cap-and-trade program, and requires a 90% removal of mercury by unit by the end of 2015. While its CPS is pending, Midwest Generation has filed an appeal of the state's mercury rule that would require a 90% fleetwide reduction in mercury emissions by July 2009.

Pennsylvania—

On February 17, 2007, the PADEP published in the Pennsylvania Bulletin regulations that would require coal-fired power plants to reduce mercury emissions by 80% by 2010 and 90% by 2015. The rule does not allow the use of emissions trading to achieve compliance. The rule became final upon publication.

At this time EME expects the Homer City facilities to achieve compliance by the 2010 deadline with mercury removal achieved by an existing flue gas desulfurization system on one generating unit and by sorbent injection on the other two units. EME has deferred making commitments for the installation of further environmental controls at the Homer City facilities at this time, but continues to study available environmental control technologies and estimated costs to reduce SO_2 and mercury and to monitor developments related to mercury and other environmental regulations.

Ambient Air Quality Standards

The US EPA designated non-attainment areas for its 8-hour ozone standard on April 30, 2004, and for its fine particulate matter standard on January 5, 2005. Almost all of EME's facilities are located in counties that have been identified as being in non-attainment with both standards. States are required to revise their SIPs for the ozone and particulate matter standards within three years of the effective date of the respective non-attainment designations. The revised SIPs are likely to require additional emission reductions from facilities that are significant emitters of ozone precursors and particulates. Any additional obligations on EME's facilities to further reduce their emissions of SO_2, NO_x and fine particulates to address local non-attainment with the 8-hour ozone and fine particulate matter standards will not be known until the states revise their SIPs. Depending upon the final standards that are adopted, EME may incur substantial costs or experience other financial impacts resulting from required capital improvements or operational changes.

On September 22, 2006 the US EPA issued a final rule that implements the revisions to its fine particulate standard originally proposed on January 17, 2006. Under the new rule, the annual standard remains the same but the 24-hour fine particulate standard is significantly more stringent. The rule may require states to impose further emission reductions beyond those necessary to meet the existing standards. EME anticipates that any such further emissions reduction obligations would not be imposed under this standard until 2015 at the earliest, and intends to consider such rules as part of its overall plan for environmental compliance.

Illinois—

Beginning with the 2003 ozone season (May 1 through September 30), EME has been required to comply with an average NO_x emission rate of 0.25 lb NO_x/MMBtu of heat input. This limitation is commonly referred to as the East St. Louis State Implementation Plan. This regulation is a State of Illinois requirement. Each of the Illinois Plants complied with this standard in 2004. Beginning with the 2004 ozone season, the Illinois Plants became subject to the federally mandated "NO_x SIP Call" regulation that provided ozone-season NO_x emission allowances to a 19-state region east of the Mississippi. This program provides for NO_x allowance trading similar to the SO_2 (acid rain) trading program already in effect.

During 2004, the Illinois Plants stayed within their NO_x allocations by augmenting their allocation with early reduction credits generated within the fleet. In 2005, the Illinois Plants used banked allowances, along with some purchased allowances, to stay within their NO_x allocations. In 2006, the Illinois Plants used purchased allowances to stay within their NO_x allocations. Midwest Generation plans to continue to purchase allowances as it implements the agreement it reached with the Illinois EPA.

The Illinois EPA has begun to develop SIPs to meet National Ambient Air Quality Standards for 8-hour ozone and fine particulates with the intent of bringing non-attainment areas, such as Chicago, into attainment. The SIPs are expected to deal with all emission sources, not just power generators, and to address emissions of NO_x, SO_2, and volatile organic compounds. These SIPs are to be submitted to the US EPA by June 15, 2007 for 8-hour ozone, and by April 5, 2008 for fine particulates.

Midwest Generation's agreement with the Illinois EPA and the pending CPS include emission controls that will contribute to ozone and fine particulate attainment. Midwest Generation expects, but cannot guarantee, that the reductions required under the agreement and the pending CPS will be sufficient for compliance with future ozone and particulate matter regulations. See "—Clean Air Act—Illinois" for further discussion.

Pennsylvania—

The Homer City facilities comply with current ozone requirements due to the selective catalytic reduction systems installed at each unit. Particulate requirements are met using a combination of scrubber reductions from Unit 3 and the purchase of SO_2 allowances. Pennsylvania has not yet proposed new regulations to implement the National Ambient Air Quality Standards for 8-hour ozone or for fine particulates. These SIPs are to be submitted to US EPA by June 15, 2007 and April 5, 2008, respectively. Although the final form of the SIPs is not yet known, at this time EME anticipates that current treatment will be sufficient to meet the SIP requirements for 8-hour ozone, and that the SIP for fine particulates will require the continued use of the existing scrubber supplemented by the purchase of SO_2 allowances.

Regional Haze—

The goal of the 1999 regional haze regulations is to restore visibility in mandatory federal Class I areas, such as national parks and wilderness areas, to natural background conditions in 60 years. Sources such as power plants that are reasonably anticipated to contribute to visibility impairment in Class I areas may be required to install BART or implement other control strategies to meet regional haze control requirements. States are required to revise their SIPs to demonstrate reasonable further progress towards meeting regional haze goals. Emission reductions achieved through other ongoing control programs may be sufficient to demonstrate reasonable progress toward the long-term goal, particularly for the first 10 to 15 year phase of the program. States must develop SIPs by December 2007. It is possible that sources subject to the CAIR will be able to satisfy their obligations under the regional haze regulations through compliance with the CAIR. However, until the SIPs are revised, EME cannot predict whether it will be required to install BART or implement other control strategies, and cannot identify the financial impacts of any additional control requirements.

The CPS, discussed above in "—Clean Air Act—Illinois," addresses emissions reductions at BART affected sources. In Pennsylvania, the PADEP considers the CAIR to meet the BART requirements, and the Homer City facilities are only required to consider reductions in emissions of suspended particulate matter (PM10), which at this time have not been developed by the state.

New Source Review Requirements

Since 1999, the US EPA has pursued a coordinated compliance and enforcement strategy to address Clean Air Act NSR compliance issues at the nation's coal-fired power plants. The NSR regulations impose certain requirements on facilities, such as electric generating stations, in the event that modifications are made to air emissions sources at a facility. The US EPA's strategy included both the filing of a number of suits against power plant owners, and the issuance of a number of administrative notices of violation to power plant owners alleging NSR violations. Neither EME nor any of its subsidiaries has been named as a defendant in these lawsuits and have not received any administrative Notices of Violation alleging NSR violations at any of their facilities.

On October 13, 2005, the US EPA proposed a change to the NSR program. The proposal put forth several options for a new emissions test based on the impact of a facility modification on a facility's maximum hourly emissions or its emissions per unit of energy produced. The existing NSR emissions test is based on the impact of a modification on a generating station's net annual emissions.

In October 2005, the US EPA announced a revised NSR strategy to take account of recent US EPA rulemakings, such as the CAIR and regional haze rules, affecting coal-fired power plants. Under the revised strategy, while the US EPA will continue to pursue filed cases and cases in active negotiation, it intends to shift its future enforcement focus from coal-fired power plants to other sectors where compliance assurance activities have the potential to produce significant environmental benefits.

Prior to EME's purchase of the Homer City facilities, the US EPA requested information under Section 114 of the Clean Air Act from the prior owners of the plant concerning physical changes at the plant. This request was part of the US EPA's industry-wide investigation of compliance by coal-fired plants with the Clean Air Act NSR requirements. On February 21, 2003, Midwest Generation received a request for information under Section 114 regarding past operations, maintenance and physical changes at the Illinois Plants from the US EPA. On July 28, 2003, Commonwealth Edison received a substantially similar request for information from the US EPA related to the same plants. In a request dated February 1, 2005, the US EPA submitted a request for additional information to Midwest Generation. Midwest Generation has provided responses to these requests. Other than these requests for information, no NSR enforcement-related proceedings have been initiated by the US EPA with respect to any of EME's facilities.

EME will continue to monitor developments with respect to the NSR program and NSR enforcement to assess what implications, if any, they will have on its facilities, its results of operations or financial position.

Water Quality Regulation

Clean Water Act—Cooling Water Intake Structures

On July 9, 2004, the US EPA published the final Phase II rule implementing Section 316(b) of the Clean Water Act establishing standards for cooling water intake structures at existing large power plants. The purpose of the regulation is to reduce substantially the number of aquatic organisms that are pinned against cooling water intake structures or drawn into cooling water systems. Pursuant to the regulation, a demonstration study must be conducted when applying for a new or renewed NPDES wastewater discharge permit. If one can demonstrate that the costs of meeting the presumptive standards set forth in the regulation are significantly greater than the costs that the US EPA assumed in its rule making or are significantly disproportionate to the expected environmental benefits, a site-specific analysis may be performed to establish alternative standards. Depending on the findings of the demonstration studies, cooling towers and/or other mechanical means of reducing impingement and entrainment of aquatic organisms may be required. EME has begun to collect impingement and entrainment data at its potentially affected Midwest Generation facilities in Illinois to begin the process of determining what corrective actions may need to be taken.

The Phase II cooling water intake structure rule was challenged in the courts, and the cases were consolidated and transferred to the United States Court of Appeals for the Second Circuit. On January 25, 2007, the Second Circuit granted the petitions challenging the rule and remanded the rule to the US EPA for further proceedings. Although the Phase II rule could have a material impact on EME's operations, EME cannot reasonably determine the financial impact on it at this time because it is still collecting the data required by the regulation and because the challenges mentioned above may affect the obligations imposed by the rule.

Illinois

The Illinois EPA is reviewing the water quality standards for the Des Plaines River adjacent to the Joliet Station and immediately downstream of the Will County Station to determine if the use classification should be upgraded. If the existing use classification is changed, the limits on the temperature of the discharges from the Joliet and Will County plants may be made more stringent. The Illinois EPA has also begun a review of the water quality standards for the Chicago River and Chicago Sanitary and Ship Canal which are adjacent to the Fisk and Crawford Stations. Proposed changes to the existing standards are still being developed. Accordingly, EME is not able to estimate the financial impact of potential changes to the water quality standards. However, the cost of additional cooling water treatment, if required, could be substantial.

Pennsylvania

The discharge from the treatment plant receiving the wastewater stream from EME's Unit 3 flue gas desulfurization system at the Homer City facilities has exceeded the stringent water-quality based limits for selenium in the station's NPDES permit. As a result, EME was notified in April 2002 by the PADEP that it was included in the Quarterly Noncompliance Report submitted to the US EPA. With PADEP's approval, EME has undertaken a pilot program utilizing biological treatment. EME prepared a draft of a consent order and agreement addressing the selenium issue and presented it to the PADEP for consideration in connection with the renewal of the station's NPDES permit. The PADEP has included civil penalties in consent agreements related to other facilities with selenium treatment issues, but the amount of civil penalties that may be assessed against EME cannot be estimated at this time.

Environmental Remediation

Under various federal, state and local environmental laws and regulations, a current or previous owner or operator of any facility, including an electric generating facility, may be required to investigate and remediate releases or threatened releases of hazardous or toxic substances or petroleum products located at that facility, and may be held liable to a governmental entity or to third parties for property damage, personal injury, natural resource damages, and investigation and remediation costs incurred by these parties in connection with these releases or threatened releases. In addition, persons who arrange for the disposal or treatment of hazardous or toxic substances at a disposal or treatment facility may be liable for the costs to remediate releases of hazardous substances from such facilities even where the disposal of such wastes was undertaken in compliance with applicable laws. Many of these laws, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980, commonly referred to as CERCLA, as amended by the Superfund Amendments and Reauthorization Act of 1986, impose liability without regard to whether the owner knew of or caused the presence of the hazardous substances, and courts have interpreted liability under these laws to be strict and joint and several.

With respect to EME's potential liabilities arising under CERCLA or similar laws for the investigation and remediation of contaminated property, EME accrues a liability to the extent the costs are probable and can be reasonably estimated. Midwest Generation has accrued approximately $3 million at December 31, 2006 for estimated environmental investigation and remediation costs for the Illinois Plants. This estimate is based upon the number of sites, the scope of work and the estimated costs for environmental activity where such expenditures could be reasonably estimated. Future estimated costs may vary based on changes in regulations or requirements of federal, state, or local governmental agencies, changes in technology, and actual costs of disposal. In addition, future remediation costs will be affected by the nature and extent of contamination discovered at the sites that requires remediation.

Given the prior history of the operations at its facilities, EME cannot be certain that the existence or extent of all contamination at its sites has been fully identified. However, based on available information, management believes that future costs in excess of the amounts disclosed on all known and quantifiable environmental contingencies will not be material to EME's financial position.

Federal, state and local laws, regulations and ordinances also govern the removal, encapsulation or disturbance of asbestos-containing materials when these materials are in poor condition or in the event of construction, remodeling, renovation or demolition of a building. Those laws and regulations may impose liability for release of asbestos-containing materials and may provide for the ability of third parties to seek recovery from owners or operators of these properties for personal injury associated with asbestos-containing materials. In connection with the ownership and operation of its facilities, EME may be liable for these costs. EME has agreed to indemnify the sellers of the Illinois Plants and the Homer City facilities with respect to specified environmental liabilities. See "—Commercial Commitments—Guarantees and Indemnities" for a discussion of these indemnities.

Climate Change

To date, the United States has chosen to pursue a voluntary greenhouse gas emissions reduction program to meet its obligations as a signatory to the United Nations Framework Convention on Climate Change. Currently a number of bills are proposed or under discussion in Congress to mandate reductions of greenhouse gas emissions. At this point, EME is unable to determine whether any of these proposals will be enacted into law or to estimate their potential effect on EME.

There have been petitions from states and other parties to compel the US EPA to regulate greenhouse gases under the CAIR. Also, in 2004, several states and environmental organizations brought a complaint in federal court in New York, alleging that several electric utility corporations are jointly and severally liable under a theory of public nuisance for damages caused by the alleged contribution to global warming resulting from carbon dioxide emissions from coal-fired power plants owned and operated by these companies or their subsidiaries. Neither EME nor its subsidiaries were named as defendants in the complaint. The case was dismissed and is currently on appeal with the United States Court of Appeals for the Second Circuit.

In April 2006, private citizens brought a complaint in federal court in Mississippi against numerous defendants, including several electric utilities, arguing that emissions from the defendants' facilities contributed to climate change and seeking monetary damages related to the 2005 hurricane season. On December 19, 2006, the plaintiffs sought permission from the court to file an amended complaint naming approximately one hundred new defendants, including EME and three of its subsidiaries. The court has not yet ruled on the plaintiffs' motion.

On December 20, 2005, seven northeastern states entered into a Memorandum of Understanding to create a regional initiative to establish a cap and trade greenhouse gas program for electric generators, referred to as the Regional Greenhouse Gas Initiative (RGGI). In August 2006, the participating states issued a model rule to be used as a basis for individual state legislative and regulatory action to implement the program. Illinois and Pennsylvania are not signatories to the RGGI, although Pennsylvania has participated as an observer of the process. Recent reports indicate that Pennsylvania is planning to announce a climate change policy that may include joining the RGGI. If Pennsylvania were to join the RGGI, this could have a material impact on EME's Homer City facilities.

In September 2006, California's Governor Schwarzenegger signed two bills into law regarding greenhouse gas emissions. The first, known as AB 32 or the California Global Warming Solutions Act of 2006, establishes a comprehensive program of regulatory and market mechanisms to achieve reductions of greenhouse gases. AB 32 requires the California Air Resources Board to develop regulations and market mechanisms targeted to reduce California's greenhouse gas emissions to 1990 levels by 2020. California Air Resources Board's mandatory program will take effect commencing 2012 and will implement incremental reductions so that greenhouse gas emissions will be reduced to 1990 levels by 2020. The second bill, known as SB 1368, requires the California Public Utilities Commission and the California Energy Commission to adopt greenhouse gas emissions performance standards for investor owned and publicly owned utilities, respectively, for long-term procurement of electricity. The standards must equal the performance of a combined-cycle gas turbine generator. The California Public Utilities Commission adopted such a standard on January 25, 2007 (which limits emissions to 1,100 pounds of carbon dioxide per MWh). The California Energy Commission must take similar action by June 30, 2007. In addition, the California Public Utilities Commission is addressing climate change related issues in various regulatory proceedings. At this time, EME believes that all of its facilities in California meet the greenhouse gas emissions performance standard contemplated by SB 1368, but EME will continue to monitor both regulations, as they are developed, for potential impact on its existing facilities and its projects under development.

The ultimate outcome of the climate change debate could have a significant economic effect on EME. Any legal obligation that would require EME to reduce substantially its emissions of carbon dioxide or would impose additional costs or charges for the emission of carbon dioxide could have a materially adverse effect on EME.

Note 13. Related Party Transactions

Specified administrative services such as payroll and employee benefit programs, all performed by Edison International or SCE employees, are shared among all affiliates of Edison International, and the costs of these corporate support services are allocated to all affiliates, including EME. Costs are allocated based on one of the following formulas: percentage of time worked, equity in investment and advances, number of employees, or multi-factor (operating revenues, operating expenses, total assets and number of employees). In addition, services of Edison International or SCE employees are sometimes directly requested by EME and these services are performed for EME's benefit. Labor and expenses of these directly requested services are specifically identified and billed at cost. EME believes the allocation methodologies utilized are reasonable. EME made reimbursements for the cost of these programs and other services, which amounted to $69 million, $84 million and $60 million in 2006, 2005 and 2004, respectively. At December 31, 2006 and 2005, the amount due to Edison International was $4 million and $7 million, respectively.

EME participates in the insurance program of Edison International, including property, general liability, workers compensation and various other specialty policies. EME's insurance premiums are generally based on EME's share of risk related to each policy. In connection with the property insurance program, a portion of the risk is reinsured by a captive insurance subsidiary of Edison International.

EME records accruals for tax liabilities and/or tax benefits which are settled quarterly according to a series of tax-allocation agreements as described in Note 1. Under these agreements, EME recognized tax liabilities (benefits) applicable to continuing operations of $81 million, $270 million and $(382) million for 2006, 2005 and 2004, respectively. See Note 10—Income Taxes. Amounts included in accounts payable—affiliates associated with the tax liabilities (benefits) totaled $(1) million at December 31, 2006 and $22 million at December 31, 2005.

Edison Mission Operation & Maintenance, Inc., an indirect, wholly owned affiliate of EME, has entered into operation and maintenance agreements with partnerships in which EME has a 50% or less ownership interest. Pursuant to the negotiated agreements, Edison Mission Operation & Maintenance is to perform all operation and maintenance activities necessary for the production of power by these partnerships' facilities. The agreements continue until terminated by either party. Edison Mission Operation & Maintenance is paid for all costs incurred with operating and maintaining such facilities and may also earn incentive compensation as set forth in the agreements. EME recorded revenues under the operation and maintenance agreements of $26 million for 2006 and $24 million for each of 2005 and 2004. Accounts receivable—affiliates for Edison Mission Operation & Maintenance totaled $7 million at both December 31, 2006 and 2005.

Specified EME subsidiaries have ownership in partnerships that sell electricity generated by their project facilities to SCE and others under the terms of long-term power purchase agreements. Sales by these partnerships to SCE under these agreements amounted to $756 million, $932 million and $824 million in 2006, 2005 and 2004, respectively.

Note 14. Supplemental Statements of Cash Flows Information

	Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Cash paid			
Interest (net of amount capitalized)	$ 297	$ 309	$ 307
Income taxes	172	149	6
Cash payments under plant operating leases	337	293	240
Details of assets acquired			
Fair value of assets acquired	$ 29	$ 154	$ —
Liabilities assumed	—	—	—
Net assets acquired	$ 29	$ 154	$ —
Non-cash activities from consolidation of variable interest entities			
Assets	$ 18	$ 37	$ —
Liabilities	4	27	—
Non-cash activities from de-consolidation of variable interest entity			
Assets	$ —	$ —	$ 220
Liabilities	—	—	254

During the year ended December 31, 2006, EME accrued $11 million in connection with the purchase price of the Wildorado wind project due upon completion of construction. In addition, EME received a capital contribution of $76 million in the form of ownership interests in a portfolio of wind projects and a small biomass project. Refer to Note 4—Acquisitions and Consolidations—Transfer of Wind Projects from an Affiliate, for further discussion.

During the year ended December 31, 2005, EME received a capital contribution of $20 million from its parent for investments in an entity which was previously owned by EME's affiliate, Edison Capital. This entity holds interests in various wind projects.

During the year ended December 31, 2004, EME declared a dividend payable to MEHC totaling $305 million.

Note 15. Quarterly Financial Data (unaudited)

2006	First	Second	Third(i)	Fourth	Total
			(in millions)		
Operating revenues	$ 514	$ 463	$ 706	$ 556	$ 2,239
Operating income	131	53	286	153	623
Income (loss) from continuing operations	75	(43)(ii)	198	86	316
Discontinued operations, net (iv)	73	4	(2)	23	98
Income (loss) before accounting change	148	(39)	196	109	414
Net income (loss)	148	(39)	196	109	414

2005	First	Second	Third(i)	Fourth	Total
Operating revenues	$ 517	$ 422	$ 680	$ 646	$ 2,265
Operating income	125	18	277	263	683
Income from continuing operations	57	19	173(iii)	165	414
Discontinued operations, net (iv)	7	21	27	(26)	29
Income before accounting change	64	40	200	139	443
Net income	64	40	200	138	442

(i) Reflects EME's seasonal pattern, in which a significant amount of earnings from domestic projects are earned and recorded in the third quarter of each year.

(ii) Reflects a $143 million pre-tax ($88 million, after tax) loss on early extinguishment of debt related to the early repayment of substantially all of EME's 10% senior notes due August 15, 2008 and 9.875% senior notes due April 15, 2011.

(iii) Reflects a $55 million pre-tax ($34 million, after tax) impairment loss on equity method investment related to the March Point project.

(iv) See Note 5—Divestitures—Discontinued Operations for more information.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Omitted pursuant to General Instruction I.(2)(c).

Code of Business Conduct and Ethics for Principal Officers

EME has adopted an Ethics and Compliance Code that applies to its principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions. The Ethics and Compliance Code is posted on the Internet website maintained by EME's ultimate parent, Edison International, at www.edisonethics.com. Any amendment to or waiver from a provision of the Ethics and Compliance Code that must be disclosed under rules and forms of the Securities and Exchange Commission will be disclosed at the same Internet website address within four business days following the date of the amendment or waiver.

ITEM 11. EXECUTIVE COMPENSATION

Omitted pursuant to General Instruction I.(2)(c).

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Omitted pursuant to General Instruction I.(2)(c).

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Omitted pursuant to General Instruction I.(2)(c).

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

INDEPENDENT ACCOUNTANT FEES

The following table sets forth the aggregate fees billed to EME (consolidated total including EME and its subsidiaries), for the fiscal years ended December 31, 2006 and December 31, 2005, by PricewaterhouseCoopers LLP:

	EME and Subsidiaries ($000)	
	2006	2005
Audit Fees	$ 2,678	$ 2,936
Audit Related Fees(1)	193	44
Tax Fees(2)	1,151	926
All Other Fees	—	—
Total	$ 4,022	$ 3,906

(1) The nature of the services comprising these fees were assurance and related services related to the performance of the audit or review of the financial statements and not reported under "Audit Fees" above.

(2) The nature of the services comprising these fees were to support compliance with federal, state and foreign tax reporting and payment requirements, including tax return review and review of tax laws, regulations or cases.

The Edison International Audit Committee reviews with management and pre-approves all audit services to be performed by the independent accountants and all non-audit services that are not prohibited and that require pre-approval under the Securities Exchange Act. The Edison International Audit Committee's pre-approval responsibilities may be delegated to one or more Edison International Audit Committee members, provided that such delegate(s) presents any pre-approval decisions to the Edison International Audit Committee at its next meeting. The independent auditors must assure that all audit and non-audit services provided to EME and its subsidiaries have been approved by the Edison International Audit Committee.

During the fiscal year ended December 31, 2006, all services performed by the independent accountants were pre-approved by the Edison International Audit Committee, regardless of whether the services required pre-approval under the Securities Exchange Act.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) (1) List of Financial Statements
See Index to Consolidated Financial Statements at Item 8 of this report.

(2) List of Financial Statement Schedules
The following financial statement schedule is included in this report:

	Page
Schedule I—Condensed Financial Information of Parent	165

All other schedules have been omitted because they are not applicable or the required information is included in the consolidated financial statements or notes thereto.

(3) List of Exhibits

Exhibit No.	Description
2.1	Asset Purchase Agreement, dated August 1, 1998, between Pennsylvania Electric Company, NGE Generation, Inc., New York State Electric & Gas Corporation and Mission Energy Westside, Inc., incorporated by reference to Exhibit 2.4 to Edison Mission Energy's Form 10-K for the year ended December 31, 1998.
2.2	Asset Sale Agreement, dated March 22, 1999, between Commonwealth Edison Company and Edison Mission Energy as to the Fossil Generating Assets, incorporated by reference to Exhibit 2.5 to Edison Mission Energy's Form 10-K for the year ended December 31, 1998.
2.3	Purchase and Sale Agreement, dated May 10, 2000, between Edison Mission Energy, P & L Coal Holdings Corporation and Gold Fields Mining Corporation, incorporated by reference to Exhibit 2.9 to Edison Mission Energy's 10-Q for the quarter ended September 30, 2000.
2.4	Stock Purchase Agreement, dated November 17, 2000 between Mission Del Sol, LLC and Texaco Inc., incorporated by reference to Exhibit 2.11 to Edison Mission Energy's Form 10-K for the year ended December 31, 2000.
2.5	Purchase Agreement, dated July 20, 2004, between Edison Mission Energy and Origin Energy New Zealand Limited, incorporated by reference to Exhibit 2.1 to Edison Mission Energy's Form 8-K dated September 30, 2004.
2.6	Purchase Agreement, dated July 29, 2004, by and among Edison Mission Energy, IPM Eagle LLP, International Power plc, Mitsui & Co., Ltd. and the other sellers on the signature page thereto, incorporated by reference to Exhibit 2.1 to Edison Mission Energy's Form 10-Q for the quarter ended September 30, 2004.
3.1	Certificate of Incorporation of Edison Mission Energy, dated August 14, 2001, incorporated by reference to Exhibit 3.1 to Edison Mission Energy's Form 8-K dated October 26, 2001.
3.1.1	Certificate of Amendment to the Certificate of Incorporation of Edison Mission Energy dated May 4, 2004, incorporated by reference to Exhibit 3.1.1 to Edison Mission Energy's Form 10-Q for the quarter ended March 31, 2004.

Exhibit No.	Description
3.2	By-Laws of Edison Mission Energy dated May 4, 2004, incorporated by reference to Exhibit 3.1.1 to Edison Mission Energy's Form 10-Q for the quarter ended March 31, 2004.
4.1	Indenture, dated as of June 6, 2006, between Edison Mission Energy and Wells Fargo Bank, National Association, as trustee, incorporated by reference to Exhibit 4.1 to Edison Mission Energy's Form 8-K dated June 8, 2006.
4.1.1	First Supplemental Indenture, dated as of June 6, 2006, between Edison Mission Energy and Wells Fargo Bank, National Association, as trustee, supplementing the Indenture, dated as of June 6, 2006, incorporated by reference to Exhibit 4.1.1 to Edison Mission Energy's Form 8-K dated June 8, 2006.
4.1.2	Second Supplemental Indenture, dated as of June 6, 2006, between Edison Mission Energy and Wells Fargo Bank, National Association, as trustee, supplementing the Indenture, dated as of June 6, 2006, incorporated by reference to Exhibit 4.1.2 to Edison Mission Energy's Form 8-K dated June 8, 2006.
4.2	Registration Rights Agreement, dated as of June 6, 2006, between Edison Mission Energy and J.P. Morgan Securities Inc., as representatives of the Initial Purchasers, incorporated by reference to Exhibit 4.2 to Edison Mission Energy's Registration Statement on Form S-4 to the Securities and Exchange Commission on September 25, 2006.
4.3	Guarantee, dated as of August 17, 2000, made by Edison Mission Energy, as Guarantor in favor of Powerton Trust I, as Owner Lessor, incorporated by reference to Exhibit 4.9 to Edison Mission Energy's and Midwest Generation, LLC's Registration Statement on Form S-4 to the Securities and Exchange Commission on April 20, 2001.
4.3.1	Schedule identifying substantially identical agreement to Guarantee constituting Exhibit 4.3 hereto, incorporated by reference to Exhibit 4.9.1 to Edison Mission Energy's and Midwest Generation, LLC's Registration Statement on Form S-4 to the Securities and Exchange Commission on April 20, 2001.
4.4	Guarantee, dated as of August 17, 2000, made by Edison Mission Energy, as Guarantor in favor of Joliet Trust I, as Owner Lessor, incorporated by reference to Exhibit 4.10 to Edison Mission Energy's and Midwest Generation, LLC's Registration Statement on Form S-4 to the Securities and Exchange Commission on April 20, 2001.
4.4.1	Schedule identifying substantially identical agreement to Guarantee constituting Exhibit 4.4 hereto, incorporated by reference to Exhibit 4.10.1 to Edison Mission Energy's and Midwest Generation, LLC's Registration Statement on Form S-4 to the Securities and Exchange Commission on April 20, 2001.
4.5	Registration Rights Agreement, dated as of August 17, 2000, among Edison Mission Energy, Midwest Generation, LLC and Credit Suisse First Boston Corporation and Lehman Brothers Inc., as representatives of the Initial Purchasers, incorporated by reference to Exhibit 4.11 to Edison Mission Energy's and Midwest Generation, LLC's Registration Statement on Form S-4 to the Securities and Exchange Commission on April 20, 2001.

Exhibit No.	Description
4.6	Participation Agreement (T1), dated as of August 17, 2000, by and among, Midwest Generation, LLC, Powerton Trust I, as the Owner Lessor, Wilmington Trust Company, as the Owner Trustee, Powerton Generation I, LLC, as the Owner Participant, Edison Mission Energy, United States Trust Company of New York, as the Lease Indenture Trustee, and United States Trust Company of New York, as the Pass Through Trustees, incorporated by reference to Exhibit 4.12 to Edison Mission Energy's and Midwest Generation, LLC's Registration Statement on Form S-4 to the Securities and Exchange Commission on April 20, 2001.
4.6.1	Schedule identifying substantially identical agreement to Participation Agreement constituting Exhibit 4.6 hereto, incorporated by reference to Exhibit 4.12.1 to Edison Mission Energy's and Midwest Generation, LLC's Registration Statement on Form S-4 to the Securities and Exchange Commission on April 20, 2001.
4.7	Participation Agreement (T1), dated as of August 17, 2000, by and among, Midwest Generation, LLC, Joliet Trust I, as the Owner Lessor, Wilmington Trust Company, as the Owner Trustee, Joliet Generation I, LLC, as the Owner Participant, Edison Mission Energy, United States Trust Company of New York, as the Lease Indenture Trustee and United States Trust Company of New York, as the Pass Through Trustees, incorporated by reference to Exhibit 4.13 to Edison Mission Energy's and Midwest Generation, LLC's Registration Statement on Form S-4 to the Securities and Exchange Commission on April 20, 2001.
4.7.1	Schedule identifying substantially identical agreement to Participation Agreement constituting Exhibit 4.7 hereto, incorporated by reference to Exhibit 4.13.1 to Edison Mission Energy's and Midwest Generation, LLC's Registration Statement on Form S-4 to the Securities and Exchange Commission on April 20, 2001.
4.8	Indenture, dated as of June 28, 1999, between Edison Mission Energy and The Bank of New York, as Trustee, incorporated by reference to Exhibit 4.1 to Edison Mission Energy's Registration Statement on Form S-4 to the Securities and Exchange Commission on February 18, 2000.
4.8.1	First Supplemental Indenture, dated as of June 28, 1999, to Indenture dated as of June 28, 1999, between Edison Mission Energy and The Bank of New York, as Trustee, incorporated by reference to Exhibit 4.2 to Edison Mission Energy's Registration Statement on Form S-4 to the Securities and Exchange Commission on February 18, 2000.
4.9	Registration Rights Agreement, dated as of June 23, 1999, between Edison Mission Energy and the Initial Purchasers specified therein, incorporated by reference to Exhibit 10.1 to Edison Mission Energy's Registration Statement on Form S-4 to the Securities and Exchange Commission on February 18, 2000.
4.10	Promissory Note ($499,450,800), dated as of August 24, 2000, by Edison Mission Energy in favor of Midwest Generation, LLC, incorporated by reference to Exhibit 4.5 to Edison Mission Energy's Form 10-K for the year ended December 31, 2000.
4.10.1	Schedule identifying substantially identical agreements to Promissory Note constituting Exhibit 4.10 hereto, incorporated by reference to Exhibit 4.5.1 to Edison Mission Energy's Form 10-K for the year ended December 31, 2000.

Exhibit No.	Description
4.11	Participation Agreement, dated as of December 7, 2001, among EME Homer City Generation L.P., Homer City OL1 LLC, as Facility Lessor and Ground Lessee, Wells Fargo Bank Northwest National Association, General Electric Capital Corporation, The Bank of New York as the Security Agent, The Bank of New York as Lease Indenture Trustee, Homer City Funding LLC and The Bank of New York as Bondholder Trustee, incorporated by reference to Exhibit 4.4 to the EME Homer City Generation L.P. Form 10-K for the year ended December 31, 2001.
4.11.1	Schedule identifying substantially identical agreements to Participation Agreement constituting Exhibit 4.11 hereto, incorporated by reference to Exhibit 4.4.1 to the EME Homer City Generation L.P. Form 10-K for the year ended December 31, 2001.
4.11.2	Appendix A (Definitions) to the Participation Agreement constituting Exhibit 4.11 hereto, incorporated by reference to Exhibit 4.4.2 to the EME Homer City Generation L.P. Form 10-K for the year ended December 31, 2004.
4.12	Open-End Mortgage, Security Agreement and Assignment of Rents, dated as of December 7, 2001, among Homer City OLI LLC, as the Owner Lessor to The Bank of New York, as Security Agent and Mortgagee, incorporated by reference to Exhibit 4.9 to the EME Homer City Generation L.P. Form 10-K for the year ended December 31, 2001.
4.12.1	Schedule identifying substantially identical agreements to Open-End Mortgage, Security Agreement and Assignment of Rents constituting Exhibit 4.12 hereto, incorporated by reference to Exhibit 4.9.1 to the EME Homer City Generation L.P. Form 10-K for the year ended December 31, 2003.
10.1	Credit Agreement, dated as of June 15, 2006, between Edison Mission Energy, the Lenders referred to therein, the Issuing Lenders referred to therein and Citicorp North America, Inc., as Administrative Agent for the Lenders and the Issuing Lenders party thereto, incorporated by reference to Exhibit 10.1 to Edison Mission Energy's Form 8-K dated June 21, 2006.
10.2	Security Agreement, dated as of June 15, 2006, between Edison Mission Energy and Citicorp North America, Inc., as Administrative Agent, incorporated by reference to Exhibit 10.2 to Edison Mission Energy's Form 8-K dated June 21, 2006.
10.3	Guarantee, dated August 1, 1998, between Edison Mission Energy, Pennsylvania Electric Company, NGE Generation, Inc. and New York State Electric & Gas Corporation, incorporated by reference to Exhibit 10.54 to Edison Mission Energy's Form 10-K for the year ended December 31, 1998.
10.4	Amended and Restated Guarantee and Collateral Agreement, dated as of December 7, 2001, made by EME Homer City Generation L.P. in favor of The Bank of New York as successor to United States Trust Company of New York, as Collateral Agent, incorporated by reference to Exhibit 10.16.4 to EME Homer City Generation L.P.'s Form 10-K for the year ended December 31, 2001.
10.5	Amended and Restated Security Deposit Agreement, dated as of December 7, 2001, among EME Homer City Generation L.P. and The Bank of New York as Collateral Agent, incorporated by reference to Exhibit 10.18.2 to the EME Homer City Generation L.P. Form 10-K for the year ended December 31, 2001.

Exhibit No.	Description
10.6	Intercompany Loan Subordination Agreement, dated March 18, 1999, among Edison Mission Holdings Co., Edison Mission Finance Co., Homer City Property Holdings, Inc., Chestnut Ridge Energy Co., Mission Energy Westside, Inc., EME Homer City Generation L.P. and United States Trust Company of New York, incorporated by reference to Exhibit 10.60.3 to Amendment No. 2 of Edison Mission Holdings Co.'s Registration Statement on Form S-4 to the Securities and Exchange Commission on February 29, 2000.
10.7	Exchange and Registration Rights Agreement, dated as of May 27, 1999, by and among the Initial Purchasers named therein, the Guarantors named therein and Edison Mission Holdings Co., incorporated by reference to Exhibit 10.1 to Edison Mission Holdings Co.'s Registration Statement on Form S-4 to the Securities and Exchange Commission on December 3, 1999.
10.8	Reimbursement Agreement, dated as of October 26, 2001, between Edison Mission Energy and Midwest Generation, LLC, incorporated by reference to Exhibit 10.15 to Edison Mission Energy's Form 10-Q for the quarter ended March 31, 2004.
10.9	Tax Allocation Agreement, dated July 2, 2001, by and between Mission Energy Holding Company and Edison Mission Energy, incorporated by reference to Exhibit 10.106 to Edison Mission Energy's Form 10-Q for the quarter ended September 30, 2002.
10.10	Administrative Agreement Re Tax Allocation Payments, dated July 2, 2002, among Edison International and subsidiary parties, incorporated by reference to Exhibit 10.107 to Edison Mission Energy's Form 10-Q for the quarter ended September 30, 2002.
31.1*	Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
31.2*	Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
32*	Statement Pursuant to 18 U.S.C. Section 1350.

* Filed herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EDISON MISSION ENERGY
(REGISTRANT)

By: /s/ W. James Scilacci

W. James Scilacci
Senior Vice President and Chief Financial Officer

Date: February 28, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Theodore F. Craver, Jr. Theodore F. Craver, Jr.	Director, Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)	February 28, 2007
/s/ Mark C. Clarke Mark C. Clarke	Vice President and Controller (Controller or Principal Accounting Officer)	February 28, 2007
/s/ Thomas R. McDaniel Thomas R. McDaniel	Director	February 28, 2007
/s/ Jacob A. Bouknight, Jr. Jacob A. Bouknight, Jr.	Director	February 28, 2007

EDISON MISSION ENERGY AND SUBSIDIARIES
CONDENSED FINANCIAL INFORMATION OF PARENT
Condensed Balance Sheets
(In millions)

	December 31, 2006	December 31, 2005
Assets		
Cash and cash equivalents	$ 813	$ 800
Short-term investments	558	183
Affiliate receivables	6	2
Other current assets	49	7
Total current assets	1,426	992
Investments in subsidiaries	4,766	4,302
Other long-term assets	233	88
Total Assets	$ 6,425	$ 5,382
Liabilities and Shareholder's Equity		
Accounts payable and accrued liabilities	$ 62	$ 81
Affiliate payables	648	286
Current maturities of long-term debt	78	—
Total current liabilities	788	367
Long-term obligations	1,599	1,598
Long-term affiliate debt	1,359	1,440
Deferred taxes and other	97	67
Total Liabilities	3,843	3,472
Common Shareholder's Equity	2,582	1,910
Total Liabilities and Shareholder's Equity	$ 6,425	$ 5,382

SCHEDULE I

EDISON MISSION ENERGY AND SUBSIDIARIES
CONDENSED FINANCIAL INFORMATION OF PARENT
Condensed Statements of Income
(In millions)

	Years Ended December 31,		
	2006	2005	2004
Operating revenues	$ 5	$ —	$ (26)
Operating expenses	(81)	(110)	(138)
Operating loss	(76)	(110)	(164)
Equity in income from continuing operations of subsidiaries	638	680	360
Interest expense and other	(346)	(270)	(389)
Income (loss) before income taxes	216	300	(193)
Benefit for income taxes	(198)	(142)	(323)
Net income	$ 414	$ 442	$ 130

EDISON MISSION ENERGY AND SUBSIDIARIES
CONDENSED FINANCIAL INFORMATION OF PARENT
Condensed Statements of Cash Flows
(In millions)

	Years Ended December 31,		
	2006	**2005**	**2004**
Net cash provided by (used in) operating activities	$ 942	$ (2,594)	$ 1,997
Net cash used in financing activities	(415)	(378)	(52)
Net cash provided by (used in) investing activities	(514)	1,796	(85)
Net increase (decrease) in cash and cash equivalents	13	(1,176)	1,860
Cash and cash equivalents at beginning of period	800	1,976	116
Cash and cash equivalents at end of period	$ 813	$ 800	$ 1,976
Cash dividends received from subsidiaries	$ 543	$ 250	$ 529