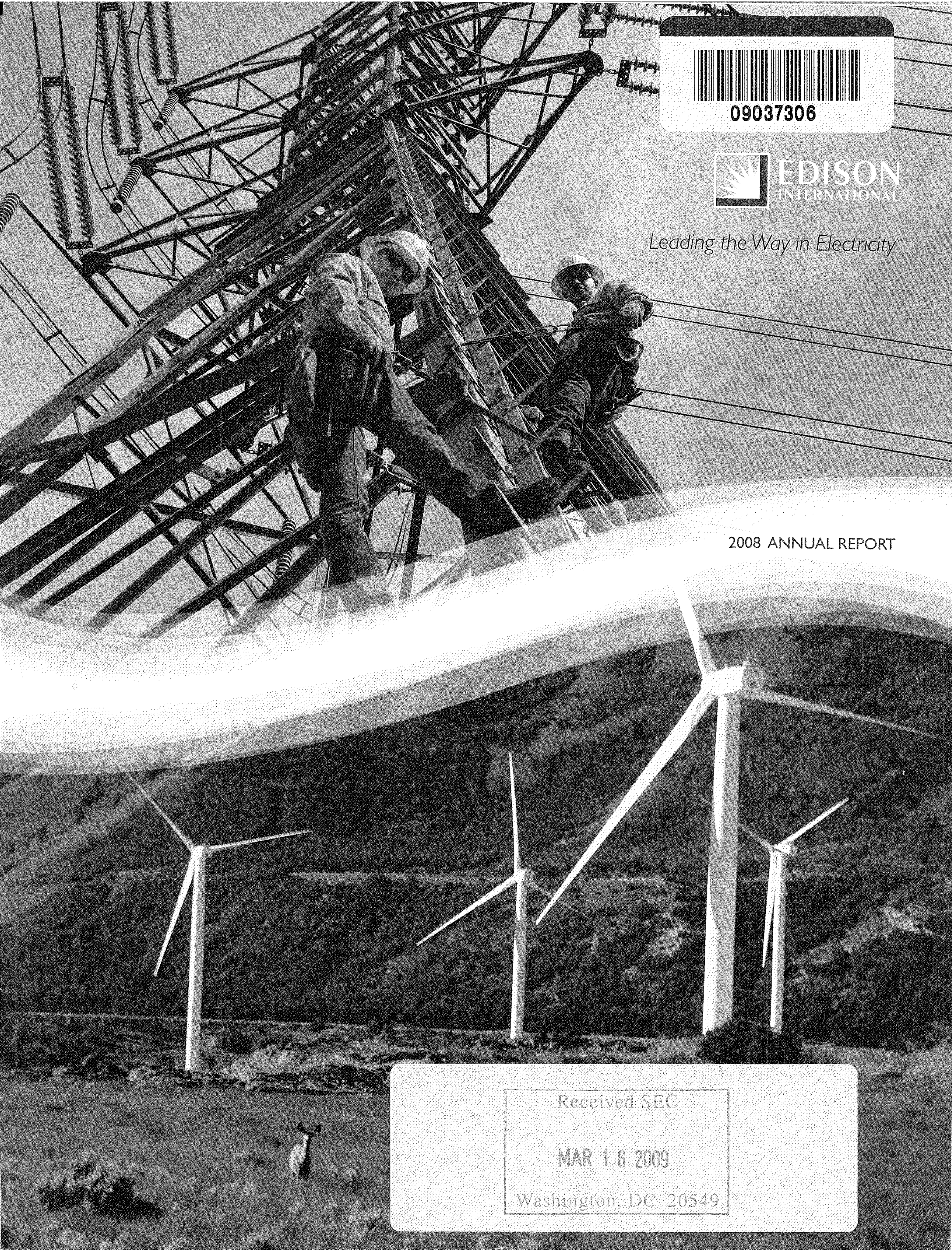
EDISON INTERNATIONAL

Leading the Way in Electricity℠

2008 ANNUAL REPORT



OUR VISION

Leading the Way in Electricity℠

OUR VALUES

- Integrity
- Excellence
- Respect
- Continuous Improvement
- Teamwork

OUR SHARED ENTERPRISE

- Together we provide an indispensable service that powers society.
- We are a single enterprise that is stronger than the sum of its parts.

OUR OPERATING PRIORITIES

- We operate safely
- We meet customer needs
- We value diversity
- We build productive partnerships
- We protect the environment
- We learn from experience and improve
- We grow the value of our business

On the cover:
(top) SCE linemen at work in Villa Park, California
(bottom) EMG's 19-megawatt wind project in Spanish Fork, Utah

FINANCIAL HIGHLIGHTS

Dollar amounts in millions, except per share data

Year ended December 31,	**2008**	2007	2006
Operating revenues	**$14,112**	$12,868	$12,169
Operating income	**$2,563**	$2,509	$2,489
Basic earnings per share from continuing operations	**$3.69**	$3.34	$3.28
Dividends paid per common share	**$1.22**	$1.16	$1.08
Total assets at December 31	**$44,615**	$37,523	$36,261
Return on equity	**13.7%**	13.6%	16.5%

BUSINESS HIGHLIGHTS

Southern California Edison

System rate base	**$12,439**	$11,719	$10,836
Capital expenditures	**$2,267**	$2,286	$2,226
Peak demand (megawatts)	**22,020**	23,303	22,889
Total system sales (kilowatt-hours, in millions)	**98,577**	97,688	96,146
Energy efficiency savings (kilowatt-hours, in millions)	**1,691**	1,635	792
Employees	**16,344**	15,442	14,362

Edison Mission Group

Generation capacity at December 31 (megawatts)	**9,849**	9,453	9,303
Wind generation (megawatts) (in operation and under construction at December 31)	**1,185**	1,013	616
Capital expenditures	**$556**	$540	$310
Employees	**1,889**	1,793	1,751

Superior execution.
Financial discipline.
Innovative approaches.

Edison International has been tested before by tough and unpredictable financial times. We endured, and ultimately grew stronger. We are facing the present economic challenges with the seriousness, and the confidence, that comes from experience.

State and national policy objectives for cleaner generation, grid reliability, and advanced energy technologies continue to offer attractive growth opportunities for Edison International. We commit ourselves to the **superior execution** of our daily operations and our plans for growth. We focus on good **financial discipline,** so that we can operate from a position of strength as opportunities and challenges arise. And our **innovative approaches** to advanced technology and environmental stewardship have earned us valuable leadership positions in a number of key areas.

We are optimistic that adhering to these fundamentals should enable us to realize our substantial growth potential and build long-term value for customers, shareholders and employees.

Fellow Shareholders:

Edison International in 2008 largely achieved the performance goals we set for ourselves at the beginning of the year, and net income grew 11 percent to a record $1.22 billion, or $3.69 per share.

Based solely on these measures, we would consider 2008 to be a good, solid year of performance. But of course it was not a normal year, for Edison International or for the economy as a whole. Our accomplishments must be viewed in the context of the dramatic decline in the economy and the stock market. Our stock price fell 39.8 percent in 2008, generally in line with the 38.5 percent decline of the S&P 500.

Our peers, measured by the Philadelphia Utility Index, performed somewhat better as a group, with a decline of 29.9 percent for the year. This index consists of "pure-play" utilities, where essentially the entire business is regulated, and "integrated" utilities like Edison International. We operate both a regulated utility, Southern California Edison (SCE), and a competitive generation business, Edison Mission Group (EMG). In 2008 our stock performed somewhat worse than the pure-play utilities, which were viewed as more insulated from the economic turmoil, but better than the pure competitive generation businesses, which were impacted greatly.

In this, my first letter to shareholders as chairman and CEO of your company, I want to share what I believe underlies the value creation opportunity at Edison International. We have a strong foundation, and we are in a good position to achieve our substantial growth objectives – but it will require superior execution, financial discipline and innovative approaches to our business.

THE FOUNDATIONS OF OUR VALUE

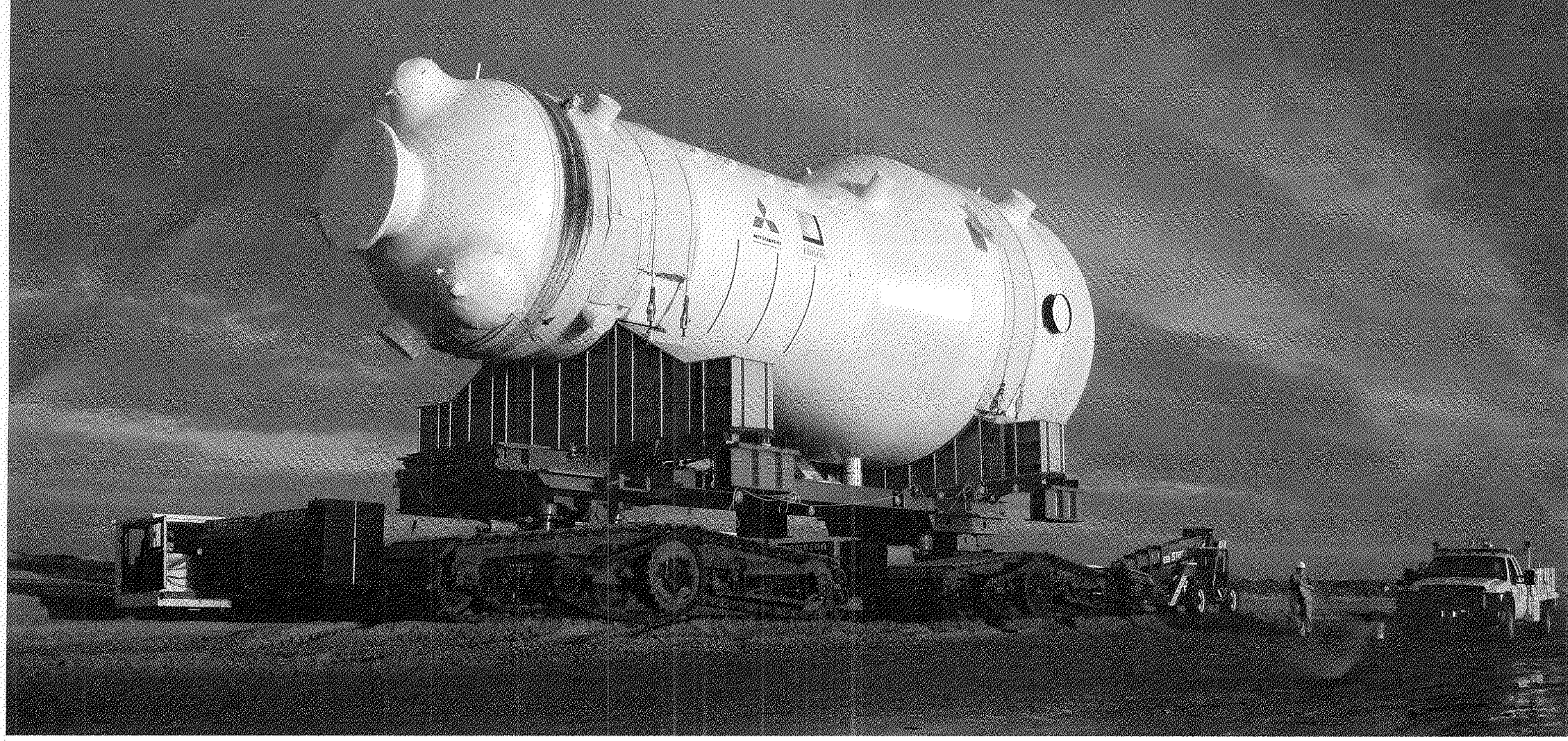
Neither the global financial crisis nor the weakened economy has altered the four most significant drivers of Edison International's growth potential, which we believe is among the best in our industry.

1. Investments in renewable energy, grid reliability, and advanced energy technologies are important public policy objectives at the national, state and local levels. Investment to meet these objectives forms the core of our growth strategy at both SCE and EMG.
2. We have the scale and stability of one of the largest electric utilities in the country, coupled with the upside opportunity of our competitive generation business and its strategic flexibility to participate in multiple markets.
3. We have a strong financial position. Our total liquidity at year-end was in excess of $5.5 billion, we have no significant long-term debt maturities until 2012, and we generate strong cash flow from operations.
4. We have skilled and committed employees, led by able and seasoned management, focused on operating safely and serving our customers and the communities in which we do business.

SUPERIOR EXECUTION OF OUR GROWTH PROGRAMS

Our ability to realize Edison International's growth potential rests principally on how we execute two initiatives: a five-year, $21 billion capital investment plan at SCE, the largest such program in our history; and the development of a large renewable energy project pipeline at EMG consisting of approximately 5,000 megawatts of potential wind and solar energy projects. Successful execution of these plans would benefit electricity customers and the environment, and dramatically grow the earning assets of the company over the next few years.

REPLACEMENT STEAM GENERATOR EN ROUTE TO SAN ONOFRE



These investment and development programs constitute a large, diverse and extremely complex volume of work. They demand superior execution on many fronts including planning, permitting, engineering, procurement and construction management.

The SCE capital investment program. SCE has increased its infrastructure investment significantly over the last three years, and 2009 will be particularly important as the company ramps up to an even greater level. Projects totaling as much as $3.6 billion are planned in five main areas:

- Reliability investments in the distribution system;
- Transmission investments, particularly to enable the development of new sources of renewable energy;
- Edison SmartConnect™, our advanced meter program;
- Replacement of steam generators to extend the life of our San Onofre Nuclear Generating Station; and,
- Our proposal to launch an innovative solar initiative using the rooftops of large commercial buildings.

In addition to the challenges associated with completing these large capital projects, there is another concern: the financial impact on SCE customers. The accelerated pace of investment in reliability and in a smarter, cleaner, electricity system will put upward pressure on SCE customer rates in 2009 and beyond, an issue to which we are acutely sensitive given the weakened economy. Declining fuel costs will partially offset rate changes in the near term, but we are taking action on multiple fronts to help our customers.

As always, we are aggressively promoting our energy-efficiency and demand-response programs to help SCE customers lower their monthly electricity bills. We offer extended payment arrangements to customers experiencing difficulty paying their bills, and rate reduction programs to income-qualified customers. For customers struggling most, we offer direct financial assistance through the Energy Assistance Fund.

We are also working with legislative leaders, public officials and consumer groups to address an inequity in electricity rates that was created unintentionally by the state legislature during the California energy crisis. Today, approximately 50 percent of SCE's residential customers shoulder 100 percent of most new costs. Reform would enable the California Public Utilities Commission to distribute costs fairly while maintaining existing protections for low-income customers.

EMG renewable energy and natural gas-fired generation development. At EMG, the core of our growth plan is the continued expansion of our wind portfolio. We made good progress in 2008, increasing our installed wind capacity by 70 percent. At year-end we had projects in nine states, with 962 megawatts in service and 223 megawatts under construction.

Our wind development pipeline consists of approximately 5,000 megawatts of potential projects in 13 states. As we identify projects to develop that meet our return criteria, our challenge is to drive them to completion through the permitting, grid interconnection, construction and financing required to bring a new wind farm on-line. This also will demand superior execution, repeated consistently across multiple projects in several states.

The wind development program will for the foreseeable future remain the anchor of our renewables business at EMG, but in 2008 we also advanced our solar program significantly. We are exploring more than 30 sites in six Western states for potential solar projects. These generally are large-scale projects of 20 to 100 megawatts per site. We are processing interconnection requests, taking steps to secure land rights, and competing for long-term power sale contracts to utilities. Significantly, we signed a strategic development agreement with a photovoltaic solar panel manufacturer, First Solar Electric, LLC, to develop large solar utility projects in certain markets.

In addition to EMG's developments in renewable energy, we are also exploring opportunities to diversify our portfolio with gas-fired generation. A major potential advance occurred in 2008 when the company was awarded a 10-year,

competitively bid power sales agreement with SCE for the output of the Walnut Creek project, a 500-megawatt gas-fired plant in the Los Angeles basin. Although uncertainties about adequate availability of emissions offsets caused us to write off some early stage project costs, we are actively pursuing these offsets and remain committed to this $600 million project.

MAINTAINING GOOD FINANCIAL DISCIPLINE

Our growth programs require large amounts of capital. It is essential that we maintain financial discipline in order to give investors the confidence to fund our projects. Financial strength is a competitive advantage we want to protect and extend.

Our short-term response to the financial crisis has been to follow our natural inclination to manage financial risks on the conservative side. In September, we took the precaution of drawing from our lines of credit approximately $2.1 billion, even though we had no immediate need for the funds. If a long line started to form at the banks, we wanted to have already been there.

We further enhanced our liquidity and tested the bond market in mid-October at SCE with a $500 million, 5.75 percent coupon offering, which was well received. We were among only a handful of companies able to raise meaningful funds during this period.

EMG has been building liquidity and extending debt maturities over the last two years with several highly favorable opportunistic financings. We did this to meet our significant growth investments and other obligations even if credit markets tightened. These efforts have provided the significant cash needed through summer 2009 to complete wind power projects in development. As long as credit markets remain difficult, the availability of project financing will be an important factor in any decision to commit to new construction projects beyond those currently planned.

For companies that remain strong and stable, the present environment may actually create opportunities. The difficulty and increased expense of obtaining investment capital, for example, only intensifies the challenge of building new power plants. That may ultimately increase the value of existing capacity and make the need for new generation all the more urgent in an economic recovery, rewarding those who are in position to move quickly. We aim to maintain the financial strength and flexibility to pursue these opportunities.

SOLAR ROOFTOP INSTALLATION, FONTANA, CALIFORNIA

INNOVATIVE APPROACHES FOR A LOW-CARBON ECONOMY

Meeting society's demands for a cleaner, more robust electricity system will require fundamental changes to the way electricity is generated, transported and distributed to customers. Transitions of this magnitude require insightful public policy, precise planning and huge sums of new capital. It also requires sufficient time for customers, workers and companies to digest the significant costs without further weakening the economy.

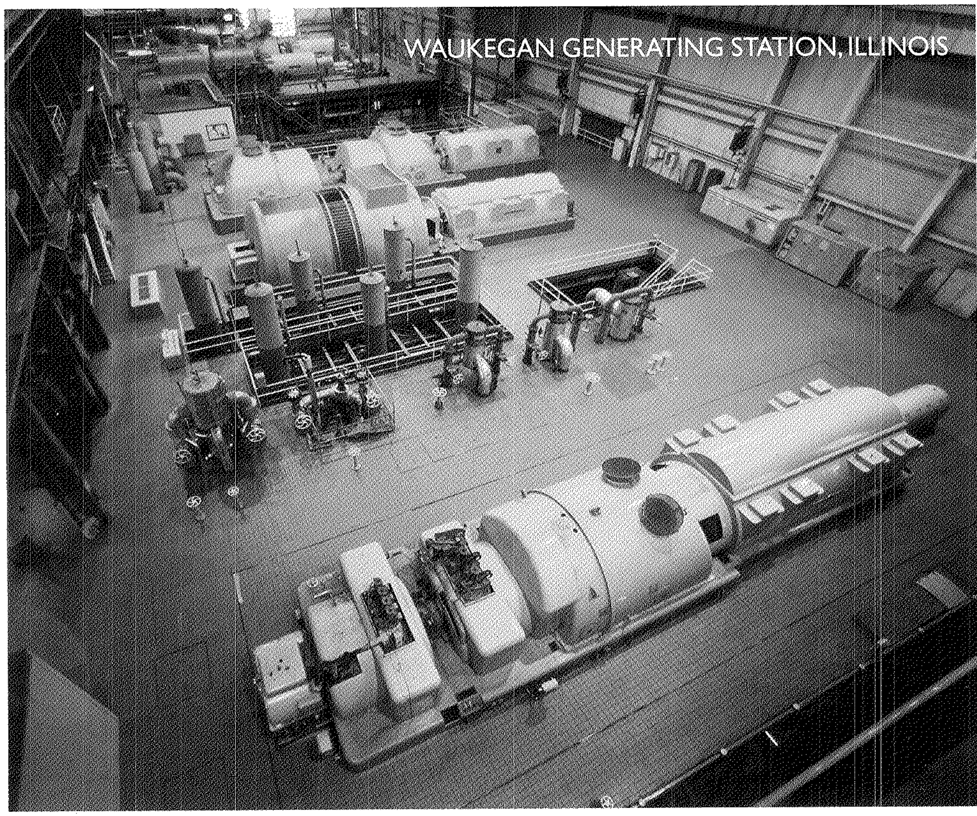
The transformation of the electricity industry requires Edison International to change as well. In many respects, we are well ahead of the curve; in other areas, we have much work to do.

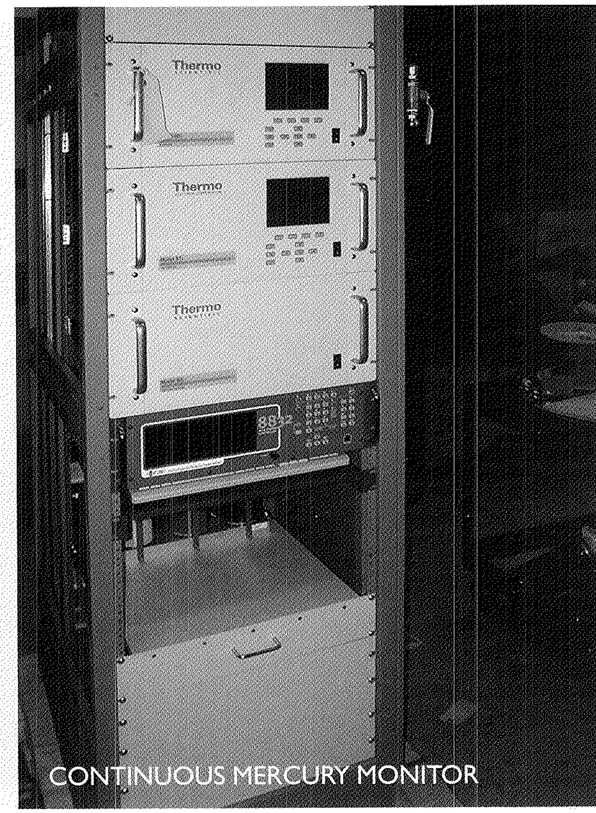
At SCE, approximately 40 percent of our generation already comes from low-carbon sources. Innovative approaches to renewable energy, energy efficiency, smart grid technology and electric transportation have made us an industry leader in these areas. This expertise will be increasingly important in the transition to a low-carbon economy, and could become a strong competitive advantage.

Significant effort and capital will be required for SCE to achieve potentially higher state-level goals for renewable energy. California's goal for the state's investor-owned utilities is for 20 percent of our customers' energy needs to come from renewable sources by 2010, and there is growing support to raise that goal to 33 percent by 2020. SCE currently leads the nation with a renewables portfolio of nearly 13 billion kilowatt-hours, representing about 16 percent of our customers' energy needs. And yet with load growth, this portfolio will need to more than double in size to meet the higher goal, and significant new transmission will need to be constructed.

At EMG, we have been transitioning our investment emphasis to the development of wind and solar generation. The growth of our renewables business both furthers, and is supported by, national goals for increased low-carbon generation.

With respect to our large fleet of merchant coal-fired generation at EMG, the future is more complicated and involves more risk. Approximately three-quarters of EMG's generation capacity is coal-fired. Coal is an abundant domestic resource, valuable for energy security in an uncertain world, and has provided low-cost, reliable electricity to


WAUKEGAN GENERATING STATION, ILLINOIS



CONTINUOUS MERCURY MONITOR

customers for decades. One half of the nation's electricity is produced by coal-fired plants. However, in addition to concerns about the traditional pollutants emitted when coal is burned, coal is also the most carbon intensive of the fuels used for generating electricity. It is the center of attention for our industry in the effort to move to a low-carbon economy.

Over the last decade, EMG has invested hundreds of millions of dollars in our coal plants to reduce emissions of mercury, nitrogen oxide, and sulfur dioxide. Some of these efforts have been leading-edge, such as the controls installed last year at three of our Illinois plants that have dramatically reduced mercury emissions. To achieve the further emissions reductions required under state and federal regulation, EMG will need either to invest billions of dollars in control equipment and emissions credits, retire the plants, or do some combination of both.

At the same time that EMG has been reducing the traditional pollutants from its coal plants, it has been working on innovative approaches to lower its carbon intensity. For example, EMG is testing biofuels such as switch grass and miscanthus that might replace some of its coal burn. Also, EMG's Powerton plant in Illinois is one of five sites selected by the Electric Power Research Institute to host research on advanced control technologies for capturing carbon emissions at an existing plant.

Achieving these environmental objectives while continuing to invest heavily in the growth of EMG's renewables business will require significant capital. Importantly, EMG pays no regular dividends to Edison International for the benefit of shareholders. Instead, it reinvests all profits to fund environmental controls and grow its low-carbon wind and solar generation portfolio. And EMG only makes a profit if it can first recover its costs through market prices in competitive electricity markets. EMG's low-cost coal fleet has generated substantial cash flow over the last few years, which has allowed it to make these investments. That cash flow has proven to be volatile and is typically weak during periods of low commodity prices, such as those experienced in the early part of this decade and currently. We are highly focused on ensuring we recover the investments already made, and require any new investments to have a reasonable prospect of providing investors with capital recovery and an adequate return on investment.

TRANSITIONS

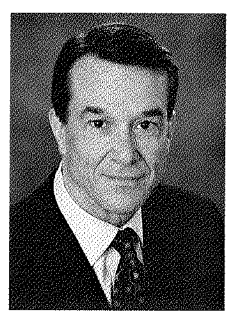
In 2008 we said farewell to three leaders who made significant contributions to the company's success. John Bryson retired from the company at the end of July after serving as Edison International's chairman and CEO for 18 years. Chief Financial Officer and long-time colleague Tom McDaniel also retired at the end of July, as did General Counsel Lon Bouknight. They contributed greatly to a substantial growth in the value of the company.

I would also like to thank and recognize Bob Smith, who retired as a member of the Board of Directors in April after 20 years of service to the company. Bob provided leadership and steadiness during times of great change and challenge. He will be missed.

OUR COMMITMENT

Thank you for your support throughout this past year. Our goal is to provide you with superior results regardless of the economic climate. I have attempted in this letter to outline the opportunities that excite us and give us optimism, as well as the challenges we need to overcome. We are deeply committed to the complex job of building value for all those who count on us to perform: our customers, our shareholders, our employees and our communities.

Over the last few months I have spent a great deal of time in the field touring our operations and talking with employees. These visits have given me an even greater appreciation for their skill, and pride in their dedication. The men and women of Edison International inspire confidence for the future of our company and are eager to take on the work that lies ahead.



Theodore F. Craver, Jr.

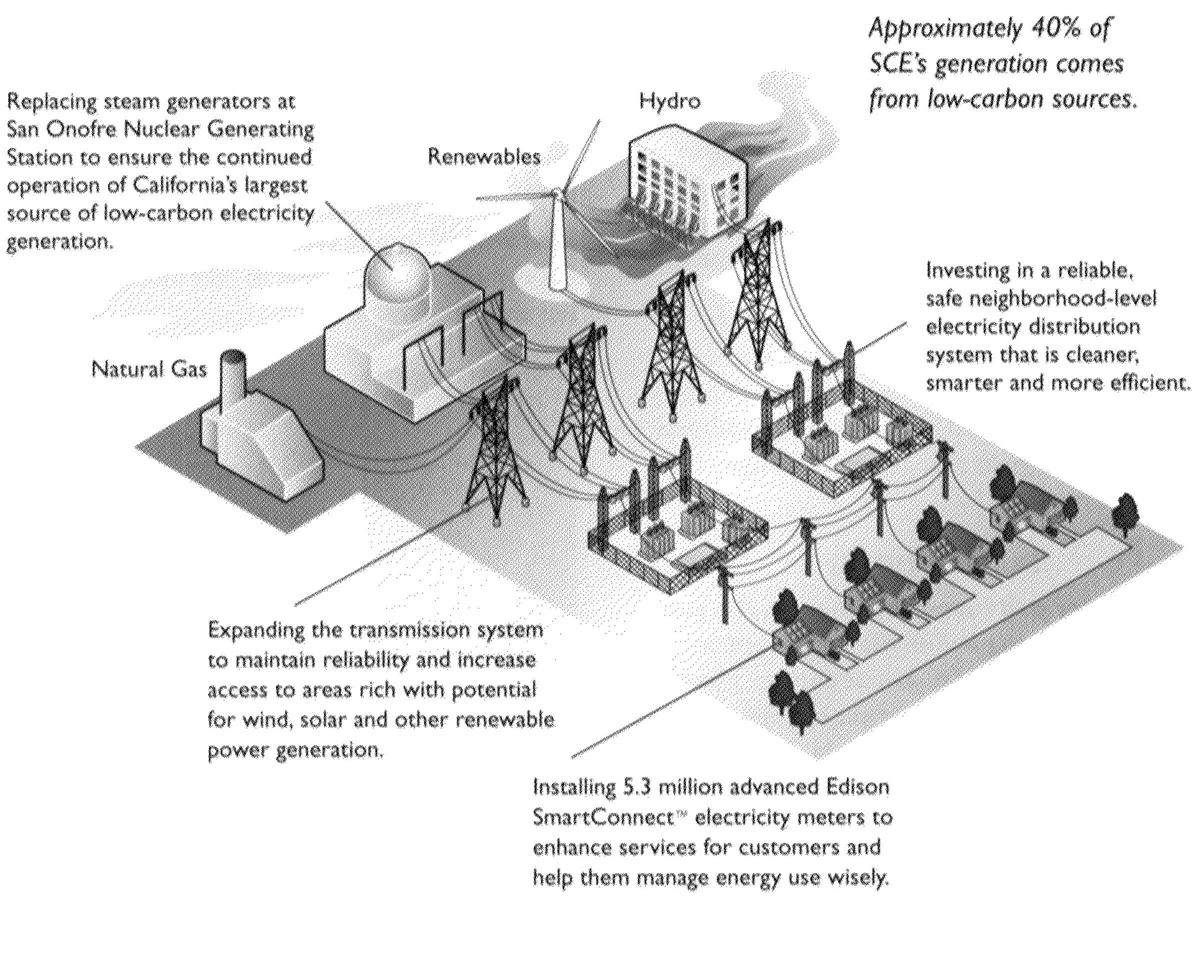
Chairman, President and Chief Executive Officer

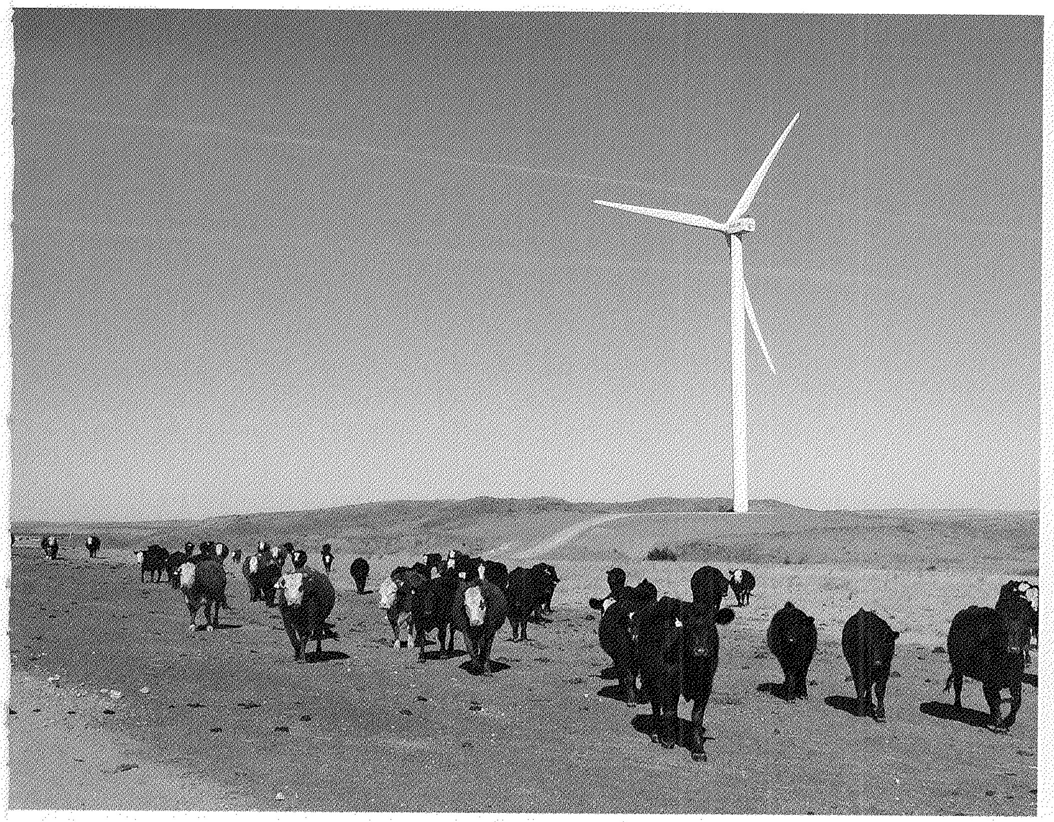
March 2, 2009

Rancho Vista Substation

Construction of SCE's state-of-the-art 500kV Rancho Vista Substation, located in Rancho Cucamonga, California, will be completed in mid-2009. This $206 million project incorporates the latest gas-insulated substation technology, and features solar photovoltaic panels on the rooftop to help provide station power. This project will improve system reliability and handle load growth in the busy Inland Empire region. The company is expanding and renewing the region's essential distribution and transmission infrastructure, making the power grid greener and smarter for 13 million Southern Californians.

Major Elements of SCE's Five-Year Capital Investment Plan





Buffalo Bear Wind Project

EMG's Buffalo Bear wind project in Oklahoma began commercial operation in late 2008. Buffalo Bear can generate up to 19 megawatts of electricity and is located near EMG's 95-megawatt Sleeping Bear wind project, which began commercial operation in 2007. Sleeping Bear sells its power to Public Service Power Company of Oklahoma, while Buffalo Bear sells its power under a long-term contract with Western Farmers Electric Cooperative. The projects can produce enough electricity to meet the needs of approximately 30,000 homes.

Edison Mission Group Wind Portfolio

(as of December 31, 2008)

Arizona
680 MW

Wyoming
141 MW

Utah
19 MW

Oklahoma
114 MW
430 MW

Nevada
825 MW

New Mexico
90 MW
100 MW
1000 MW

Texas
241 MW
70 MW
400 MW

Iowa
145 MW
220 MW

Minnesota
145 MW
165 MW

Nebraska
53 MW
282 MW

Illinois
520 MW

Maryland
60 MW

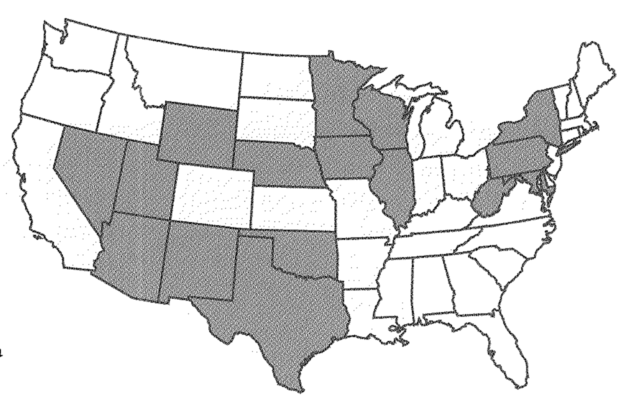
Wisconsin
100 MW

New York
195 MW

West Virginia
117 MW

Pennsylvania
67 MW

	MW
Total Operating	962
Total Construction	223
	1,185
Total Pipeline	4,994



Artificial Kelp Reef

SCE completed construction in 2008 of a 175-acre artificial giant kelp reef off the coast near the company's San Onofre Nuclear Generating Station. SCE built the reef, the largest environmental project of its kind in the United States, to mitigate impacts from the plant's use of ocean water for cooling. Kelp is the marine equivalent of a rainforest. It allows sea life to survive, providing food, shelter, camouflage and an environment for spawning. The reef includes the placement of 120,000 tons of rock on the ocean floor and is expected to produce the nation's first sustainable artificial kelp forest, attracting many species of coastal fish and invertebrates that depend on such underwater habitats for shelter and food.

SOLAR ROOFTOP PROGRAM

This proposed $875 million initiative would place 250 megawatts of solar generation on 65 million square feet of unused Southern California commercial rooftops. The project was prompted by recent advances in solar technology that reduce the cost of installed photovoltaic generation. When combined with the size of SCE's investment, the resulting costs per unit are projected to be half that of common photovoltaic installations in California. SCE completed the first of 150 proposed installations in late 2008 with the placement of 33,700 advanced thin-film solar panels on a 600,000-square-foot warehouse roof in Fontana, California, creating the largest single rooftop solar photovoltaic array in the state. A final California Public Utilities Commission decision is expected in spring 2009.

STEAM GENERATOR REPLACEMENT

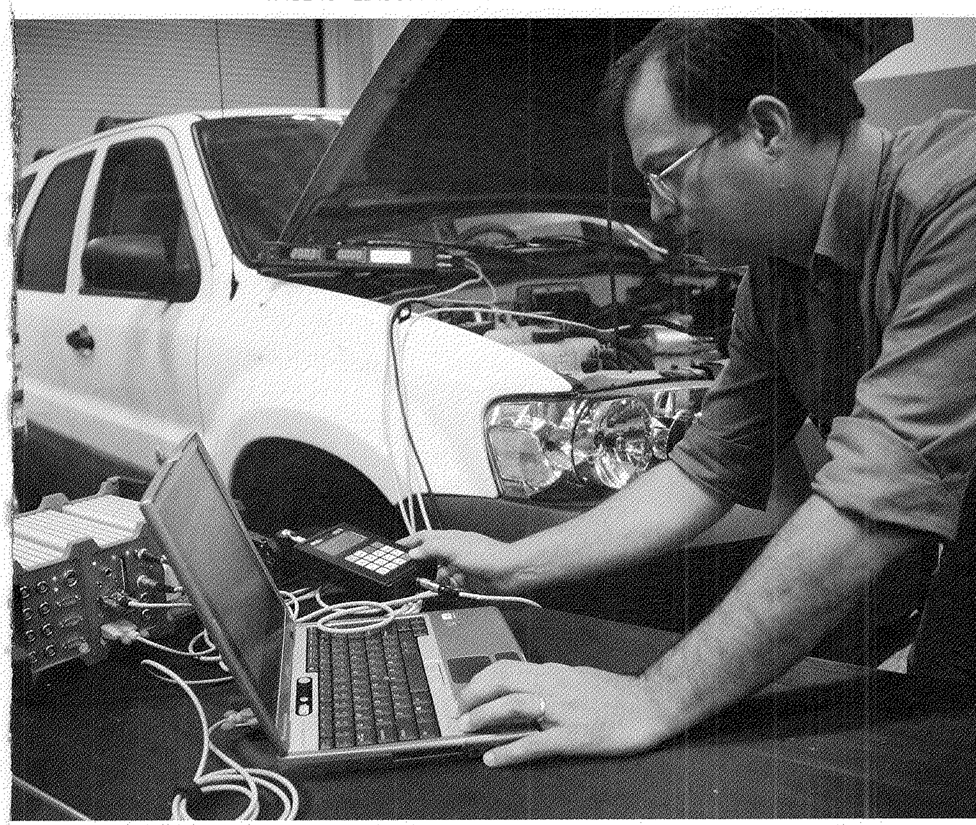
At SCE's San Onofre Nuclear Generating Station, the largest construction project since the two operating units were built in the 1980s is under way. The plant recently took delivery of the first two of four new 640-ton, 65-foot steam generators that will replace components nearing the end of their service. This investment in the utility's largest asset means the plant can serve out its initial license period, which runs until 2022, and beyond if license renewal proves feasible. The continued operation of Southern California's largest source of reliable, low-carbon generation through 2022 also means that customers will save as much as $1 billion when compared to replacement power costs.

EDISON SMARTCONNECT

The California Public Utilities Commission in 2008 approved $1.63 billion for SCE's award-winning advanced metering program, known as Edison SmartConnect. SCE plans to install 5.3 million smart meters beginning in 2009, providing residential and small-business customers with greatly improved tools and services to help them manage energy use wisely. The resulting sustained energy conservation could reduce overall peak power consumption by an estimated 1,000 megawatts – the output of a major power plant.

ADVANCED MERCURY EMISSIONS CONTROLS

EMG in 2006 signed a ground-breaking agreement with the Illinois Environmental Protection Agency



Electric Transportation

SCE's Electric Vehicle Technical Center in Pomona, California – unique in the utility industry – provides a broad range of electric transportation services, focusing on solutions for automakers, battery manufacturers, government agencies, and business and industrial fleet customers. In 2008, more than 400 national and international public officials, as well as executives from the automobile and utility industries, visited the technical center. Also in 2008, SCE and Ford Motor Company expanded their industry-leading evaluation of plug-in hybrid prototypes to include the U.S. Department of Energy, the Electric Power Research Institute, and several major U.S. utilities. In addition, SCE formed a new partnership with Mitsubishi Motors to evaluate and demonstrate the market potential of its new iMiEV electric vehicle.

related to the six coal-fired plants the company operates in that state. As part of the agreement, EMG completed mercury emission control installations in 2008 at its Waukegan plant and at Crawford and Fisk stations in Chicago. These sites are consistently achieving in the range of 80 percent removal of mercury emissions since EMG began using activated carbon injection (ACI) to remove mercury from the coal combustion process. The construction of the ACI systems on the balance of the fleet will be completed by the summer of 2009. EMG pioneered the use of ACI and was among a small number of companies that did early field-testing of the process through a grant from the U.S. Department of Energy in 2006 and 2007.

ENERGY EFFICIENCY

For more than 25 years, SCE has offered its customers award-winning energy-efficiency programs to help them save energy, reduce their electricity bills, and help the environment. From 2006 to 2008, SCE had the highest goals in the nation for energy-efficiency savings – and beat them. For the three-year program cycle, SCE helped customers achieve more than 4 billion kilowatt-hours of energy savings and 713 megawatts of demand reduction. For the upcoming 2009 to 2011 program cycle, SCE once again has the highest energy savings goals in the nation: 3.5 billion kilowatt-hours of savings and 741 megawatts of demand reduction.

SAFETY CULTURE

Edison International made progress strengthening the company's safety culture in 2008, working toward the goal of an injury-free workplace. The findings of a safety culture survey conducted in 2007 were used by business units across the company to implement tailored safety initiatives. The company achieved a reduction in OSHA-recordable injuries over the previous year. This included standout performance at EMG's Crawford and Will County stations, which earned the Outstanding Safety and Health Performance Award from the Illinois Safety Council in 2008. The award is based on year-over-year improvements in recordable accidents and days lost from work due to

Serving Our Communities

Employees at EMG's Powerton Station volunteered their time in 2008 to rebuild the home of an elderly woman in Peoria, Illinois, identified by a non-profit agency in the area. More than 50 station employees and their families worked evenings and weekends over a three-month period, building new plumbing, rewiring the house, repairing siding and windows, replacing floors, installing a new thermostat, painting and more. In 2008, Edison International employees, retirees and their families volunteered 227,000 hours in their communities. The company gave $12.8 million in shareholder-funded contributions, while employees donated nearly $3.9 million of their own money.

injury. The company's progress to date, combined with a continued focus on underlying cultural issues, position Edison International well for continued safety performance improvements in 2009 and beyond.

ETHICS AND COMPLIANCE

Edison International continues to further strengthen its ethics and compliance programs. The company's efforts include a substantial emphasis on ethics training for all employees. In 2008, executives, managers and supervisors received additional training that stressed the key role leaders must play in reinforcing a healthy ethics culture. During the year, all non-union employees completed the annual ethics and compliance certification process. This process requires employees to take personal accountability by self-reporting issues that may not comply with the Ethics and Compliance Code. Employees also have around-the-clock access to the Ethics Helpline to raise and identify issues and concerns or obtain advice. In 2008, the company also introduced the "When to Question/When to Support" communications campaign encouraging employees to speak up when they see a problem or an opportunity to improve performance.

LIVING OUR VALUES

In 2008, Edison International strengthened its high-performance culture through a comprehensive values education and employee engagement effort around the core values of Integrity, Excellence, Respect, Continuous Improvement and Teamwork. The program culminated in the Chairman's Award, a company-wide recognition program that celebrates the work of 40 extraordinary employees and their contributions to the company. The work has helped drive greater levels of awareness, understanding and commitment across the organization. Survey results in 2008 indicate that employees recognize the importance of values-based performance.

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Glossary

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

AB	Assembly Bill
ACC	Arizona Corporation Commission
Ameren	Ameren Corporation
AFUDC	allowance for funds used during construction
APS	Arizona Public Service Company
ARO(s)	asset retirement obligation(s)
Brooklyn Navy Yard	Brooklyn Navy Yard Cogeneration Partners, L.P.
Btu	British Thermal units
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CARB	California Air Resources Board
Commonwealth Edison	Commonwealth Edison Company
CDWR	California Department of Water Resources
CEC	California Energy Commission
CONE	Cost of new entry
CPS	Combined Pollutant Standard
CPSD	Consumer Protection and Safety Division
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
D.C. District Court	U.S. District Court for the District of Columbia
DOE	United States Department of Energy
DOJ	Department of Justice
DPV2	Devers-Palo Verde II
DRA	Division of Ratepayer Advocates
DWP	Los Angeles Department of Water & Power
EITF	Emerging Issues Task Force
EITF No. 01-8	EITF Issue No. 01-8, Determining Whether an Arrangement Contains a Lease
EIA	Energy Information Administration
EME	Edison Mission Energy
EME Homer City	EME Homer City Generation L.P.
EMG	Edison Mission Group Inc.
EMMT	Edison Mission Marketing & Trading, Inc.
EPAct 2005	Energy Policy Act of 2005
EPS	earnings per share
ERRA	energy resource recovery account
Exelon Generation	Exelon Generation Company LLC
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	flue gas desulfurization
FGIC	Financial Guarantee Insurance Company

FIN 39-1	Financial Accounting Standards Board Interpretation No. 39-1, Amendment of FASB Interpretation No. 39
FIN 46(R)	Financial Accounting Standards Board Interpretation No. 46, Consolidation of Variable Interest Entities
FIN 46(R)-6	Financial Accounting Standards Board Interpretation No. 46(R)-6, Determining Variability to be Considered in Applying FIN 46(R)
FIN 47	Financial Accounting Standards Board Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations
FIN 48	Financial Accounting Standards Board Interpretation No. 48, Accounting for Uncertainty in Income Taxes – an interpretation of FAS 109
Fitch	Fitch Ratings
FPA	Federal Power Act
FSP	FASB Staff Position
FSP FAS 13-2	FASB Staff Position FAS 13-2, Accounting for a Change or Projected Change in the Timing of Cash Flows Relating to Income Taxes Generated by a Leveraged Lease Transaction
FSP SFAS 142-3	FASB Staff Position No. SFAS 142-3, Determination of the Useful Life of Intangible Assets
FTRs	firm transmission rights
GAAP	general accepted accounting principles
GHG	greenhouse gas
Global Settlement	A settlement that has been negotiated between Edison International and the IRS, which, if consummated, would resolve asserted deficiencies related to Edison International's deferral of income taxes associated with certain of its cross-border, leveraged leases and all other outstanding tax disputes for open tax years 1986 through 2002, including certain affirmative claims for unrecognized tax benefits. There can be no assurance about the timing of such settlement or that a final settlement will be ultimately consummated.
GRC	General Rate Case
GWh	gigawatt-hours
Illinois EPA	Illinois Environmental Protection Agency
Illinois Plants	EME's largest power plants (fossil fuel) located in Illinois
Investor-Owned Utilities	SCE, SDG&E and PG&E
IPM	a consortium comprised of International Power plc (70%) and Mitsui & Co., Ltd. (30)%
IRS	Internal Revenue Service
ISO	California Independent System Operator
kWh(s)	kilowatt-hour(s)
LIBOR	London Interbank Offered Rate
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MECIBV	MEC International B.V.
MEHC	Mission Energy Holding Company
Midland Cogen	Midland Cogeneration Venture
Midwest Generation	Midwest Generation, LLC
MMBTU	million British units
MISO	Midwest Independent Transmission System Operator

Mohave	Mohave Generating Station
Moody's	Moody's Investors Service
MRTU	Market Redesign Technology Upgrade
MW	megawatts
MWh	megawatt-hours
NAPP	Northern Appalachian
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NOV	notice of violation
NO_x	nitrogen oxide
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NYISO	New York Independent System Operator
PADEP	Pennsylvania Department of Environmental Protection
Palo Verde	Palo Verde Nuclear Generating Station
PBOP(s)	postretirement benefits other than pension(s)
PBR	performance-based ratemaking
PG&E	Pacific Gas & Electric Company
PJM	PJM Interconnection, LLC
POD	Presiding Officer's Decision
PRB	Powder River Basin
PURPA	Public Utility Regulatory Policies Act of 1978
PX	California Power Exchange
QF(s)	qualifying facility(ies)
RGGI	Regional Greenhouse Gas Initiative
RICO	Racketeer Influenced and Corrupt Organization
ROE	return on equity
RPM	reliability pricing model
S&P	Standard & Poor's
SAB	Staff Accounting Bulletin
San Onofre	San Onofre Nuclear Generating Station
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison Company
SCR	selective catalytic reduction
SDG&E	San Diego Gas & Electric
SFAS	Statement of Financial Accounting Standards issued by the FASB
SFAS No. 71	Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation
SFAS No. 98	Statement of Financial Accounting Standards No. 98, Sale-Leaseback Transactions Involving Real Estate
SFAS No. 115	Statement of Financial Accounting Standards No. 115, Accounting for certain Investments in Debt and Equity Securities
SFAS No. 123(R)	Statement of Financial Accounting Standards No. 123(R), Share-Based Payment (revised 2004)

SFAS No. 133	Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities
SFAS No. 141(R)	Statement of Financial Accounting Standards No. 141(R), Business Combinations
SFAS No. 142	Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets
SFAS No. 143	Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations
SFAS No. 144	Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets
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 Postretirement Plans
SFAS No. 159	Statement of Financial Accounting Standards No. 159, The Fair Value Option for Financial Assets and Financial Liabilities
SFAS No. 160	Statement of Financial Accounting Standards No. 160, Noncontrolling Interests in Consolidated Financial Statements
SFAS No. 161	Statement of Financial Accounting Standards No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133
SIP(s)	State Implementation Plan(s)
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SRP	Salt River Project Agricultural Improvement and Power District
the Tribes	Navajo Nation and Hopi Tribe
TURN	The Utility Reform Network
US EPA	United States Environmental Protection Agency
VIE(s)	variable interest entity(ies)

INTRODUCTION

This MD&A contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements reflect Edison International's current expectations and projections about future events based on Edison International'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 Edison International that is incorporated in this report, or that refers to or incorporates this report, may also contain forward-looking statements. In this 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 of 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 Edison International or its subsidiaries, include, but are not limited to:

- the cost of capital and the ability to borrow funds and access to capital markets on favorable terms, particularly in light of current credit conditions in the capital markets;
- the effect of current economic conditions on the availability and creditworthiness of counterparties and the resulting effects on liquidity in the power and fuel markets and/or the ability of counterparties to pay amounts owed in excess of collateral provided in support of their obligations;
- the ability to procure sufficient resources to meet expected customer needs in the event of significant counterparty defaults under power-purchase agreements;
- changes in the fair value of investments and other assets;
- the ability of Edison International to meet its financial obligations and to pay dividends on its common stock;
- the ability of SCE to recover its costs in a timely manner from its customers through regulated rates;
- decisions and other actions by the CPUC, the FERC and other regulatory authorities and delays in regulatory actions;
- market risks affecting SCE's energy procurement activities;
- changes in interest rates, rates of inflation including those rates which may be adjusted by public utility regulators, and foreign exchange rates;
- governmental, statutory, regulatory or administrative changes or initiatives affecting the electricity industry, including the market structure rules applicable to each market;
- environmental laws and regulations, both at the state and federal levels, that could require additional expenditures or otherwise affect the cost and manner of doing business;
- risks associated with operating nuclear and other power generating facilities, including operating risks, nuclear fuel storage, equipment failure, availability, heat rate, output, availability and cost of spare parts, and cost of repairs and retrofits;
- the cost and availability of labor, equipment and materials;
- the ability to obtain sufficient insurance, including insurance relating to SCE's nuclear facilities and wildfire-related liability, and to recover the costs of such insurance;
- effects of legal proceedings, changes in or interpretations of tax laws, rates or policies, and changes in accounting standards;

- creditworthiness of suppliers and other project participants and their ability to deliver goods and services under their contractual obligations to EME and its subsidiaries or to pay damages if they fail to fulfill those obligations;
- the outcome of disputes with the IRS and other tax authorities regarding tax positions taken by Edison International;
- the continued participation of Edison International's subsidiaries in tax-allocation and payment agreements;
- supply and demand for electric capacity and energy, and the resulting prices and dispatch volumes, in the wholesale markets to which EMG's generating units have access;
- the cost and availability of coal, natural gas, fuel oil, nuclear fuel, and associated transportation to the extent not recovered through regulated rate cost escalation provisions or balancing accounts;
- the cost and availability of emission credits or allowances for emission credits;
- transmission congestion in and to each market area and the resulting differences in prices between delivery points;
- the ability to provide sufficient collateral in support of hedging activities and purchased power and fuel;
- the risk of counterparty default in hedging transactions or power-purchase and fuel contracts;
- 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;
- the difficulty of predicting wholesale prices, transmission congestion, energy demand and other aspects of the complex and volatile markets in which EMG and its subsidiaries participate;
- general political, economic and business conditions;
- weather conditions, natural disasters and other unforeseen events; and
- the risks inherent in the development of generation projects as well as transmission and distribution infrastructure replacement and expansion including those related to siting, financing, construction, permitting, and governmental approvals.

Additional information about risks and uncertainties, including more detail about the factors described above, are discussed throughout this MD&A and in the "Risk Factors" section included in Part I, Item 1A of Edison International's Annual Report on Form 10-K. Readers are urged to read this entire report, including the information incorporated by reference, and carefully consider the risks, uncertainties and other factors that affect Edison International's business. Forward-looking statements speak only as of the date they are made and Edison International is not obligated to publicly update or revise forward-looking statements. Readers should review future reports filed by Edison International with the Securities & Exchange Commission.

In this MD&A, except when stated to the contrary, references to each of Edison International, SCE, EMG, EME or Edison Capital mean each such company with its subsidiaries on a consolidated basis. References to Edison International (parent) or parent company mean Edison International on a stand-alone basis, not consolidated with its subsidiaries.

This MD&A is presented in 12 major sections. The company-by-company discussion of SCE, EMG, and Edison International (parent) includes discussions of liquidity, market risk exposures, and other matters (as relevant to each principal business segment). The remaining sections discuss Edison International on a consolidated basis. The consolidated sections should be read in conjunction with the discussion of each company's section.

EDISON INTERNATIONAL: MANAGEMENT OVERVIEW

Introduction

Edison International is a holding company whose principal operating subsidiaries are SCE, a rate-regulated electric utility, and EMG, the holding company of Edison International's nonutility power generation (EME) and financial services (Edison Capital) segments. EME is engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from independent power production facilities, and Edison Capital provides capital and financial services, with no plans to make new investments.

Areas of Business Focus

Financial Markets and Economic Conditions

Global financial markets are experiencing severe credit tightening and a significant increase in volatility, causing access to capital markets to become subject to increased uncertainty and borrowing costs. In response, U.S. and foreign governments and Central Banks have intervened with programs designed to increase liquidity and restore confidence.

Edison International's subsidiaries are capital intensive businesses and depend on access to the financial markets to fund capital expenditures, meet contractual obligations, support energy procurement and margin and collateral requirements. SCE has significant planned capital expenditures to replace and expand its distribution and transmission infrastructure, and to construct and replace generation assets. EMG has expanded its business development activities to grow and diversify its existing portfolio of power projects, including building new power plants. In addition, EMG has environmental compliance requirements (discussed below) as well as ongoing capital expenditures for its existing generation fleet. Both SCE's and EMG's capital plans will require liquidity and access to capital markets at reasonable rates in the future. See "SCE: Liquidity," "EMG: Liquidity," and "Commitments, Guarantees and Indemnities" for further discussion.

Due to the instability of the financial markets and their participants, and to provide protection against a liquidity crisis, Edison International and its subsidiaries borrowed under their various credit facilities a total of \$2.39 billion (including \$1.29 billion for SCE, \$851 million for EMG, and \$250 million for Edison International (parent)) during the second half of 2008, although there was no immediate need for such funds. As of December 31, 2008, Edison International had \$5.57 billion of available liquidity made up of \$3.92 billion of cash and short-term investments, as well as \$1.65 billion remaining available under credit facilities. In addition, in October 2008, SCE issued \$500 million of 5.75% first and refunding mortgage bonds due in 2014. The bond proceeds further augmented SCE's cash position. Edison International and its subsidiaries do not have any material long-term debt obligations that mature until 2012. See "SCE: Liquidity" and "EMG: Liquidity" for further discussion. While the capital markets are expected to recover over time, it is uncertain how long it will be before a recovery occurs. Long-term disruption in the capital markets could adversely affect Edison International's business plans and potentially impact Edison International's financial position.

SCE relies on power-purchase contracts to meet a significant portion of its resource requirements. The financial crisis may adversely affect the ability of counterparties to access the capital markets, as needed, to perform under contracts upon which SCE will rely to meet new generation and renewables portfolio standard requirements. Additionally, if counterparties fail to deliver under power-purchase contracts, SCE would be exposed to potentially volatile spot markets for buying replacement power, but would expect to recover any additional costs through regulatory mechanisms. The volatile market conditions have also affected the value of trusts established at SCE to fund future long-term pension, other postretirement benefits, and nuclear decommissioning obligations. The market decline has decreased the funded status of these plans and unless the market recovers, will result in increased future expense and higher funding levels. SCE currently recovers and expects to continue to recover its pension, other postretirement benefits, and decommissioning costs, through customer rates and therefore funded cost increases are not expected to impact earnings, but may impact the timing of cash flows (see "SCE: Liquidity" and "SCE: Other Developments" for further discussion).

SCE operates in a large and economically diverse service territory that covers central, coastal and southern California. Economic conditions are also affecting SCE's customers and the demand for electricity. California's economy is experiencing rising unemployment and increased foreclosures and bankruptcies. During 2008, SCE experienced a 10% increase in customer disconnects and a slight increase in the dollar amounts written off for uncollectible customer accounts, compared to 2007. In a February 2009 Integrated Energy Policy Report filed with the CEC for purposes of electricity resource planning, SCE forecast a 4.3% decrease in kWh sales in 2009, compared to 2008. About one-half of this decline is the result of a transition from a warmer than normal summer in 2008 to a more typical summer in 2009. The CPUC-authorized decoupling revenue mechanisms allow for differences in revenue resulting from actual and forecast volumetric electricity sales to be collected from or refunded to ratepayers and therefore insulate SCE's short-term earnings from the economic contractions occurring in the U.S. and California. However, a prolonged period of lower sales could decrease future earnings as a result of lower levels of investment required to meet customer needs. SCE's rates are expected to increase in this period of economic downturn, which may further impact customers. See "SCE: Regulatory Matters — Impact of Regulatory Matters on Customer Rates," "— 2009 General Rate Case Proceeding," and "— Energy Resource Recovery Account Proceedings" for further discussion. Under SCE's tiered rate structure, rate increases are concentrated and not borne by all customers.

With respect to EMG, disruptions in the capital markets affected in 2008, and may continue to affect EMG's ability to finance already-developed wind projects and future commitments and projects, including significant outstanding capital commitments for wind turbines. Furthermore, these disruptions may affect how EMG addresses its commitments with respect to environmental compliance, as discussed below. As a result, pending recovery of the capital markets, EMG intends to preserve capital by focusing on a selective growth strategy (primarily completion of projects under construction, including the Big Sky wind project in Illinois, and development of sites for future renewable projects deploying current turbine commitments), and using its cash and future cash flow to meet existing contractual commitments. Depending upon financing conditions, EMG may elect to postpone and/or cancel wind turbine commitments, subject to the provisions of the relevant contracts. See "EMG: Liquidity — Capital Expenditures" and "Commitments, Guarantees and Indemnities — Turbine Commitments" for further discussion. Moreover, disruption in the financial markets appears to have reduced trading activity in power markets which may affect the level and duration of future hedging activity and potentially increase the volatility of earnings. Long-term disruption in the capital markets could adversely affect EME's business plans and financial position.

The American Recovery and Reinvestment Act of 2009

President Obama signed the American Recovery and Reinvestment Act of 2009 (the "Act") into law on February 17, 2009. The law contains direct spending measures and tax cuts totaling approximately $787 billion. The Act provides production tax credits for a ten-year period for new wind projects placed in service prior to December 31, 2012 and provides that, in lieu of the production tax credit, renewable developers may make an election to claim either a 30% investment tax credit or a grant for a 30% reimbursement of expenses associated with specified energy property. The Act also contains a one year extension of the 50% bonus depreciation, with an extra year available for long lived property, which includes transmission and distribution assets. Energy spending initiatives in the Act include: $6 billion in loan guarantees for renewable energy and transmission, $4.5 billion to be spent on smart grid investments, $5 billion for weatherization and $3.1 billion in state energy program funds to promote energy efficiency. The Act provides significant support to plug-in hybrid electric vehicle commercialization, including $2 billion in grants for advanced batteries and new or enhanced tax credits for vehicle manufacturing, infrastructure and vehicle purchases, as well as $400 million for port and truck-stop electrification.

Commodity Prices

The market price for merchant energy in PJM increased significantly during the first half of 2008 and then decreased significantly in the second half of the year. The average 24-hour PJM market price for energy per MWh at the Northern Illinois Hub and Homer City busbar was higher in 2008 as compared to 2007 by 7.6% and 13.1%, respectively. However, since June 30, 2008, forward energy prices in PJM have decreased substantially driven by lower natural gas prices and the financial market developments discussed above. At December 31, 2008, forward energy market prices for 2009 for the Northern Illinois Hub and PJM West Hub have decreased by 38% and 42%, respectively, since June 30, 2008. At the same time, the average cost of fuel per MWh increased in 2008 by 16% at Midwest Generation and 4% at EME Homer City. At December 31, 2008, Midwest Generation and EME Homer City had contracted for substantially all of their coal requirements for 2009. Unless these energy prices change, energy gross margins for unhedged volumes from Midwest Generation and EME Homer City will decrease from 2008. See "Market Risk Exposures — Commodity Price Risk" for further discussion.

SCE purchases approximately 44% of its resource needs. SCE expects that these purchases could increase significantly as the CDWR energy contracts are phased out by 2011 and SCE enters into new or novated contracts to replace or assume responsibility for the energy supplied from the CDWR contracts. In addition to SCE's Mountainview and peaker plants, approximately 46% of SCE's power purchase requirements are subject to natural gas price volatility. Natural gas prices increased significantly during the first half of 2008 and decreased significantly in the second half of the year. Because SCE recovers its procurement costs through the ERRA balancing account mechanism, these market fluctuations do not impact earnings, but can build rapidly and can greatly impact cash flow and customer rates. See "Current Regulatory Developments — Impact of Regulatory Matters on Customer Rates" and "— Energy Resource Recovery Account Proceedings."

Growth Activities and Capital Commitments

Although SCE is experiencing significant growth in actual and planned capital expenditures to improve reliability and expand capability of its distribution and transmission infrastructure, to construct and replace generation assets, and to deploy advanced metering infrastructure, the level of future growth is dependent on a final outcome of its 2009 GRC and other pending CPUC and FERC proceedings. SCE's 2009 through 2013 capital investment plan includes total capital spending in the range of $17.1 billion to $21 billion. See "SCE: Regulatory Matters — Current Regulatory Developments — 2009 General Rate Case Proceeding," and "SCE: Liquidity — Capital Expenditures" for further discussions. These plans would involve the most significant infrastructure build-out of its kind that SCE has undertaken in years. The completion of the projects, the timing of expenditures, and the associated recovery may be affected by permitting requirements and delays, construction delays, availability of labor, equipment and materials, financing, legal and regulatory developments, weather, economic conditions and other unforeseen conditions. In addition, SCE has pending FERC proceedings related to its 2009 FERC Rate Case and CWIP incentive filings that may further impact SCE's capital investment plan.

As a result of the financial markets and economic condition, discussed above, EMG intends to focus on a more selective growth strategy as described above. At December 31, 2008, EME had 962 MW of wind projects in service and three wind projects under construction with an EME *pro rata* share of 223 MW, with scheduled completion dates during 2009. EME's wind projects under construction are currently funded through equity. EME has contracts to purchase 942 MW of new turbines with scheduled payment obligations of up to $706 million in 2009 and $232 million in 2010. EME plans to use a portion of these turbines to complete a 240 MW planned wind project in Illinois, referred to as the Big Sky wind project. EME plans to use the remaining turbines to support construction of new projects, subject to meeting investment criteria and availability of financing. See "EMG: Liquidity — Capital Expenditures" and "Commitments, Guarantees and Indemnities — Turbine Commitments" for further discussion.

Federal and State Income Taxes

Edison International has negotiated the material terms of a Global Settlement with the IRS which, if consummated, would resolve cross-border, leveraged lease issues in their entirety and all other outstanding tax disputes for open tax years 1986 through 2002, including certain affirmative claims for unrecognized tax benefits. See "Edison International Notes to Consolidated Financial Statements — Note 4. Income Taxes." Consummation of the Global Settlement is subject to review by the Staff of the Joint Committee on Taxation, a committee of the United States Congress (the "Joint Committee"). The IRS submitted the pertinent terms of the Global Settlement to the Joint Committee during the fourth quarter of 2008, and its response is currently pending. Edison International cannot predict when such review will be completed or the outcome of such review. See "Other Developments — Federal and State Income Taxes" for further information.

Environmental Developments

Climate Change Regulation

The content of potential climate change regulation in the future remains uncertain. While debate continues at the national level over domestic climate policy and the appropriate scope and terms of any federal legislation, many states are developing state-specific measures or participating in regional legislative initiatives to reduce GHG emissions. State and regional regulations may vary and may be more stringent and costly than federal legislative proposals currently being debated in U.S. Congress. Key uncertainties include whether a cap-and-trade program will be implemented similar to the US EPA Acid Rain Program, and, if implemented, whether emission allowances would be provided to affected parties without cost for a period of time. In the absence of legislation, it is also possible that CO_2 will be regulated by the US EPA pursuant to authority granted under the CAA in its current form. Furthermore, the rate of decrease in GHG emissions and the cost to purchase allowances would be significant factors in determining whether environmental controls for other emissions would be economic to install. Programs to reduce GHG emissions could significantly increase the cost of generating electricity from fossil fuels as well as the cost of purchased power. In the case of utilities, like SCE, these costs are generally borne by customers, whereas the increased costs for competitive generation must be recovered through market prices for electricity. The potential impact on Edison International's subsidiaries will depend upon how the factors discussed above and many other considerations are resolved.

In the absence of any federally imposed climate change regulation, California's Global Warming Solutions Act of 2006 (also known as AB32) set an overall goal of reducing GHG emissions to 1990 levels by 2020. The program, which is being established by the CARB, to implement AB32 includes, among other measures, an increase to the existing CPUC-imposed renewables portfolio standard of 20% by 2010 to a 33% renewables procurement standard by 2020. Compliance with the 33% renewables portfolio standard would require, among other items, substantial additional power purchase contracts and capital expenditures to expand SCE's distribution and transmission infrastructure, all at a significant cost.

Air Quality Regulations in 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 an Illinois rule called the CPS. All of the Midwest Generation's Illinois coal-fired electric generating units are subject to the CPS.

Under the CPS, Midwest Generation is required to achieve specific lower emission rates by specified dates. Midwest Generation has not decided upon a particular combination of retrofits to meet the required step down in emission rates. Midwest Generation continues to review alternatives, including interim compliance solutions. The CPS also specifies that specific control technologies are to be installed on some units by specified dates. In these cases, Midwest Generation must either install the required technology by the specified deadline or shut down the unit.

Midwest Generation is in the process of completing engineering work for the potential installation of SCR equipment on Units 5 and 6 at the Powerton Station and SNCR equipment on Unit 6 at the Joliet Station. The SCR equipment at Powerton is currently estimated to cost $500 million and the SNCR equipment on Unit 6 at the Joliet Station is currently estimated to cost $13 million (both figures are in 2008 dollars). This technology combination represents one possible compliance plan for the NO_x emission rates. Midwest Generation is evaluating other potential solutions that are less costly to meet the NO_x emissions rate that combine the use of alternative NO_x removal technologies with certain unit shutdowns.

The engineering work at the Powerton Station also includes the potential installation of FGD equipment on Units 5 and 6, and Midwest Generation currently estimates approximately $1 billion (in 2008 dollars) of capital expenditures would be required for the FGD equipment at the Powerton Station. Midwest Generation also determined these capital expenditures could be reduced if the construction work sequence of FGD and SCR at the Powerton Station were reversed. The complexity of the Powerton Station installation and construction interferences are representative of the balance of the fleet and Midwest Generation currently estimates approximately $650/kW for any FGD installation it elects to make on other units.

A decision to make these improvements has not been made. Midwest Generation is still evaluating all technology and unit shutdown combinations, including interim and alternative compliance solutions. For further discussion, see "Other Developments — Environmental Matters — Air Quality Regulation."

Water Quality Regulations

Federal water quality regulations regulate the discharge of pollutants into federal waters, the heat of effluent discharges and the location, design and construction of cooling water intake structures at generation facilities. State regulations also cover certain discharges that are not regulated at the federal level.

In the absence of federal regulations, which are currently the subject of litigation and rulemaking, California is developing a policy on ocean-based once-through cooling structures, although the timing of such policy becoming effective is uncertain. The policy is expected to have a substantial effect on grid reliability in the CAISO service area, including on operations at San Onofre and on SCE's ability to procure generating capacity from fossil-fueled plants using ocean water once-through cooling systems. As of December 31, 2008, approximately 18,500 MW in the CAISO service area would be subject to this once-through cooling policy.

On October 26, 2007, the Illinois EPA filed a proposed rule with the Illinois Pollution Control Board that would establish more stringent thermal and effluent water quality standards for the Chicago Area Waterway System and Lower Des Plaines River. Midwest Generation's Fisk, Crawford and Will County Stations all use water from the Chicago Area Waterway System and its Joliet Station uses water from the Lower Des Plaines River for cooling purposes. The rule, if implemented, is expected to affect the manner in which those stations use water for station cooling.

The proposed rule is the subject of an administrative proceeding before the Illinois Pollution Control Board and must be approved by the Illinois Pollution Control Board and the Illinois Joint Committee on Administrative Rules. Following state adoption and approval, the US EPA also must approve the rule. Hearings began on January 28, 2008, and are continuing in 2009. Midwest Generation is a party in those proceedings. At this time, it is not possible to predict the timing for resolution of the proceeding, the final form of the rule, or how it would impact the operation of the affected stations; however, significant capital expenditures may be required depending on the form of the final rule. In addition, the outcome of these proceedings may affect Midwest Generation's plans for compliance with CPS discussed above.

See "Other Developments — Environmental Matters" for a further discussion of these and other environmental matters.

2008 Earnings Performance

The table below presents Edison International's earnings for the years ended December 31, 2008, 2007 and 2006, and the relative contributions by its subsidiaries.

In millions — Year Ended December 31,	Earnings (Loss) 2008	2007	2006
Earnings (Loss) from Continuing Operations:			
SCE	**$ 683**	$ 707	$ 776
EMG	**561**	412	334
Edison International (parent) and other	**(29)**	(19)	(27)
Edison International Consolidated Earnings from Continuing Operations	**1,215**	1,100	1,083
Earnings (Loss) from Discontinued Operations	**—**	(2)	97
Cumulative effect of accounting change – net of tax	**—**	—	1
Edison International Consolidated	**$ 1,215**	$ 1,098	$ 1,181

Earnings (Loss) from Continuing Operations

2008 vs. 2007

SCE's earnings from continuing operations were $683 million in 2008, compared with earnings of $707 million in 2007. The decrease in 2008 was mainly attributable to a $49 million charge associated with the CPUC decision on SCE's performance-based ratemaking mechanism recorded in 2008 and a $31 million tax benefit from the resolution of the income tax treatment of certain environmental remediation costs recorded in 2007, partially offset by higher operating income related to rule base growth, including authorized energy efficiency incentives, and lower net interest expense.

EMG's earnings from continuing operations were $561 million in 2008, compared with earnings of $412 million in 2007. EMG's 2008 increase was mainly due to a $148 million, after tax, loss on early extinguishment of debt recorded in 2007, higher operating income at EMG's Midwest Generation, positive results from new wind projects in operation, and higher trading income at EMMT. These earnings were offset by lower results from the Big 4 projects, lower interest income, a loss arising from the termination of a natural gas turbine supply agreement, and lower results at EMG's Homer City facilities and Edison Capital.

SOUTHERN CALIFORNIA EDISON COMPANY

SCE: REGULATORY MATTERS

Overview of Ratemaking Mechanisms

SCE is an investor-owned utility company providing electricity to retail customers in central, coastal and southern California. SCE is regulated by the CPUC and the FERC. SCE bills its retail customers for the sale of electricity at rates authorized by the CPUC. These rates are discussed below under four categories: base rates, cost-recovery rates, energy efficiency incentives and CDWR-related rates. SCE sells unbundled transmission service and wholesale power at rates and under tariffs authorized by the FERC.

Base Rates

Revenue arising from base rates from the CPUC and the FERC are designed to provide SCE a reasonable opportunity to recover its costs and earn an authorized return on SCE's net investment in generation, transmission and distribution facilities (or rate base). These base rates provide for recovery of operations and maintenance costs, capital-related carrying costs (depreciation, taxes and interest) and a return or profit, on a forecast basis.

Base rates related to SCE's generation and distribution functions are authorized by the CPUC through a triennial process called the GRC. In a GRC proceeding, SCE files an application with the CPUC to update its authorized annual revenue requirement for a base year and two subsequent years. After a review process and hearings, the CPUC sets an annual revenue requirement for the base year which is made up of the carrying cost on capital investment (depreciation, return and taxes), plus the authorized level of operation and maintenance expense. The return is established by multiplying an authorized rate of return, determined in the separate cost of capital proceedings (as discussed below), by rate base (the value of assets on which SCE earns a rate of return for investors). In its GRC proceedings, SCE also submits testimony regarding its need for capital spending on a forecast basis which is reviewed and approved, if found reasonable by the CPUC. Adjustments to the revenue requirement for the remaining two years of a typical three-year GRC cycle are requested from the CPUC, based on criteria established in the GRC proceeding which generally include annual allowances for escalation in operation and maintenance costs, forecasted changes in capital-related investments and related costs and the timing and number of expected nuclear refueling outages and their related forecasted costs. See "— Current Regulatory Developments — 2009 General Rate Case Proceeding" for SCE's current annual revenue requirement.

The CPUC-authorized decoupling revenue mechanisms allow for differences in revenue resulting from actual and forecast volumetric electricity sales to be collected from or refunded to ratepayers and therefore do not impact SCE's earnings. Differences between authorized and actual operating costs, other than cost-recovery costs (see below), do impact earnings.

Base rate revenue related to SCE's transmission facilities are authorized by the FERC, as needed, in periodic proceedings that are similar to the CPUC's GRC proceeding, except that requested rate changes are generally implemented either 60 days after the application is filed or after a maximum five month suspension. Revenue collected prior to a final FERC decision is recognized as revenue, but is subject to refund. Revenue authorized under FERC jurisdiction that varies from forecast is not subject to balancing account mechanisms, is not recoverable or refundable and can therefore impact operating returns.

SCE's capital structure and related authorized rate of return, is regulated by the CPUC and the FERC. The CPUC jurisdictional cost of capital is applicable to the costs requested through CPUC jurisdictional base rates. The FERC jurisdictional cost of capital is applicable to FERC jurisdictional base rates designed to recover transmission costs. Currently, the CPUC determines SCE's cost of capital in a multi-year proceeding occurring every three years. SCE expects that the current capital structure and authorized rate of return will remain in place until January 2011, absent any potential annual adjustment, as discussed below. SCE's current authorized capital structure is 48% common equity, 43% long-term debt and 9% preferred equity. SCE's current authorized cost of long-term debt is 6.22%, authorized cost of preferred equity is 6.01% and authorized return on common equity is 11.5%. The three-year cost of capital mechanism provides for an automatic readjustment to SCE's capital costs during the years between the cost of capital filings if certain thresholds are reached on an annual basis. SCE's next potential adjustment will occur at the end of September 2009, effective for 2010. As a result, depending on financial market conditions, SCE is subject to the potential earnings impact of actual financing costs being above or below its authorized rates of 6.22% and 6.01% for new long-term debt and preferred equity financings, respectively, during 2009.

Cost-Recovery Rates

Revenue requirements to recover SCE's costs of fuel, purchased-power, demand-side management programs, nuclear decommissioning, public purpose programs, certain operation and maintenance expenses, and depreciation expense related to certain projects are authorized in various CPUC proceedings on a cost-recovery basis, with no markup for return or profit. Approximately 62% of SCE's annual revenue relates to the recovery of these costs. Although the CPUC authorizes balancing account mechanisms to refund or recover any differences between forecasted and actual costs, under- or over-collections in these balancing accounts can build rapidly due to fluctuating prices (particularly for purchased-power) and can greatly impact cash flows. The majority of costs eligible for recovery through cost-recovery rates are subject to CPUC reasonableness reviews, and thus could negatively impact earnings and cash flows if found to be unreasonable and disallowed.

Energy Efficiency Shareholder Risk/Reward Incentive Mechanism

The CPUC has adopted an Energy Efficiency Risk/Reward Incentive Mechanism covering two three-year periods (2006 – 2008 and 2009 – 2011). The mechanism allows for both financial incentives and economic penalties based on SCE's performance toward meeting CPUC goals for energy efficiency. Under this mechanism, SCE has the opportunity to earn an incentive of 9% of the value of total energy efficiency savings if it achieves between 85% and 100% of its energy efficiency goals for the cumulative three year period or can earn 12% of the value of energy efficiency savings if 100% or greater of its goals are achieved. Economic penalties would be imposed in the event SCE achieves less than 65% of its goals. The mechanism has a deadband between 65% and 85% of energy efficiency goals, where no economic penalty or incentive would be earned. The mechanism allows for two progress payments, subject to a 35% holdback, for estimated progress towards meeting CPUC-authorized 3-year goals and a third payment for final measured performance towards those goals, which includes the payment of any holdback. SCE may retain the first and second progress payments as long as it meets a minimum of 65% of the goals, as measured by the CPUC in the final payment. If SCE falls below the 65% level, the amount of the progress payments and economic penalties would be deducted from future earnings awards. Both incentives and economic penalties for each three-year period are capped at $200 million. There is no assurance that SCE will meet its goals of energy efficiency incentive earnings in any given year. In addition, certain aspects of the energy efficiency incentive mechanism remain subject to CPUC review and possible modification. See "Current Regulatory Developments — Energy Efficiency Shareholder Risk/Reward Incentive Mechanism" for further discussion of current developments related to the 2006 – 2008 program cycle.

CDWR-Related Rates

As a result of the California energy crisis, in 2001 the CDWR entered into contracts to purchase power for sale at cost directly to SCE's retail customers and issued bonds to finance those power purchases. The CDWR's total statewide power charge and bond charge revenue requirements are allocated by the CPUC among the customers of the Investor-Owned Utilities. SCE bills and collects from its customers the costs of power purchased and sold by the CDWR, CDWR bond-related charges and direct access exit fees. The CDWR-related charges and a portion of direct access exit fees (approximately $2.2 billion was collected in 2008) are remitted directly to the CDWR, are not recognized as electric utility revenue by SCE and therefore have no impact on SCE's earnings; however, they do impact customer rates. See "— Impact of Regulatory Matters on Customer Rates" for further discussion.

Current Regulatory Developments

This section of the MD&A describes significant regulatory issues that may impact SCE's financial condition or results of operations.

Impact of Regulatory Matters on Customer Rates

Throughout the year, SCE changes rates to implement various regulatory decisions. SCE's current system average rate is 13.7¢ per-kWh (2.8¢ per-kWh related to CDWR, which is not recognized as revenue by SCE).

SCE expects to implement a rate change March 1, 2009 related to 2009 procurement-related costs and the 2009 FERC rate case offset by decreases in the 2009 CDWR power charge revenue requirement. This rate change is expected to result in a system average rate of 13.4¢ per-kWh (2.3¢ per-kWh related to CDWR, which is not recognized as revenue by SCE). See "— Energy Resource Recovery Account Proceedings — 2008 ERRA Revenue Requirements Forecast" and "— 2009 FERC Rate Case" for further information.

During the 2001 energy crisis, the California Legislature passed a bill, AB 1X, which implemented a tiered rate structure that capped, or fixed, the rates for almost half of SCE's residential customers. As a result, any residential revenue requirement increase is allocated to the remaining residential customers. This causes wide variation in the average rates SCE's residential customers pay. This rate inequity is causing increasingly high bills for a subset of SCE's customers. SCE is currently working with the CPUC, consumer groups, and key California public officials to seek support for a means to mitigate the effects of AB 1X.

In May 2007, the CPUC initiated a rulemaking to determine whether, or subject to what conditions, direct access could be restored in California. The proceeding was initially divided into three phases, with the first phase addressing whether the CPUC had the legal authority to lift the suspension of direct access under AB 1X. In February 2008, the CPUC issued a decision, finding that the CPUC could not lift the direct access suspension as long as the CDWR continues to supply power to retail customers as a party to its existing power contracts. The reopening of Direct Access may have an impact on customer rates, however, SCE is unable to predict the outcome or impact of this process at this time.

In November 2008, the CPUC issued a subsequent decision, finding that there are sufficient potential benefits to ratepayers to establish a process that phases-out the CDWR's remaining involvement in supplying power to Investor-Owned Utility customers. The November 2008 decision sets a target goal of novating/replacing by January 1, 2010 all remaining CDWR energy contracts so that the novated/replacement contracts are held instead by the Investor-Owned Utilities. SCE cannot predict whether or not the expedited phase-out of the CDWR contracts will occur on commercially feasible terms and the outcome of the financial impact on SCE.

2009 General Rate Case Proceeding

In February 2009, the Administrative Law Judge issued a revised proposed decision on SCE's 2009 GRC. In addition, CPUC President Peevey further revised his alternate proposed decision in this proceeding. The Administrative Law Judge's revised proposed decision would authorize a $4.6 billion base revenue requirement for 2009, a 24% increase over the 2006 authorized revenue requirement of $3.7 billion and base revenue requirements of $4.8 billion in 2010 and $4.9 billion in 2011. If adopted as currently drafted, this proposed decision would require SCE to reduce its planned capital expenditures in 2009 and 2010 by $2.0 billion with further reductions to be made in 2011, and reduce its forecast operating and maintenance expenditures by more than $400 million. The impacts of these expenditure reductions may compromise SCE's ability to comply with regulatory requirements, maintain its electric system, and provide reliable service to its customers. CPUC President Peevey's revised alternate proposed decision would authorize a $4.9 billion base revenue requirement for 2009, a 30% increase over the 2006 authorized revenue requirement of $3.7 billion, and a methodology for calculating post-test year revenue requirements that would result in an approximate revenue requirement of $5.1 billion in 2010 and $5.4 billion in 2011. While the revised alternate proposed decision authorizes revenue requirements below the level requested in SCE's GRC Application, if adopted as currently drafted, the proposed decision would provide SCE adequate funding to serve its customers. See "SCE: Liquidity" for further discussion of the impact on capital spending.

Both alternate decisions grant SCE's request for the authority to transfer the assets and liabilities of Mountainview Power Company, LLC to SCE. This transfer would facilitate operations of the power plant and reduce administrative compliance requirements. If approved, SCE would expect to record one-time accounting gains of $49 million and $14 million in the form of regulatory assets to recognize differences in the accounting treatment for non-regulated and rate-regulated entities related to equity AFUDC, and capitalization of acquisition costs, respectively. There would be no economic impact to customers from this change as compared to the existing FERC-approved power-purchase agreement; as these amounts would have been recognized over the life of that agreement and have no impact on cash flows. The transfer of Mountainview Power Company, LLC to SCE is also subject to FERC approval which is dependent on final approval of SCE's 2009 GRC Application.

SCE cannot predict whether the CPUC will ultimately adopt one or the other of these proposed decisions.

Energy Efficiency Shareholder Risk/Reward Incentive Mechanism

As described above under the heading " — Overview of Ratemaking Mechanisms — Energy Efficiency Shareholder Risk/Reward Incentive Mechanism," the CPUC has adopted an Energy Efficiency Risk/Reward Incentive Mechanism. Under the mechanism, if SCE achieves all of its energy efficiency goals, and delivers customer benefits of approximately $1.2 billion, the three-year earnings opportunity for the 2006 – 2008 period would be approximately $146 million pre-tax. On December 18, 2008, the CPUC approved SCE's first progress payment for 2006 – 2007 energy efficiency performances using SCE's quarterly savings report rather than the CPUC verification report which was delayed. However, the CPUC increased the holdback percentage (for this progress payment only) from the originally authorized 35%, to 65%, resulting in a first progress payment of $25 million which is expected to be collected through rates in 2009. The DRA and TURN filed a request for rehearing of the December decision approving the first progress payment. SCE does not believe the request for rehearing will affect the first progress payment award but cannot predict the outcome of this proceeding.

Pursuant to the adopted mechanism, future progress payments are expected to be based on CPUC verification reports. If the CPUC's verification report is again delayed in 2009, the CPUC may approve the second progress payment based upon SCE's quarterly savings report, subject to another review of the progress payment holdback percentage. Currently, SCE intends to file its request for its second progress payment using SCE's final quarterly savings report on March 2, 2009 for the second progress payment. SCE currently projects (using a 65% holdback percentage), based on preliminary results and on the current energy efficiency mechanism guidelines, that it will record a second progress payment in the range of $14 million to $26 million upon CPUC approval, which is expected in the fourth quarter of 2009 for the 2006 – 2008 program cycle. SCE expects to collect this progress payment in rates in 2010. Based on the current mechanism, SCE estimates that it will meet 100% of its energy efficiency goals for the 2006 – 2008 period.

On January 29, 2009, the CPUC issued a new rulemaking intended to address issues with the current mechanism, including delays in the verification process, utility concerns about methodologies used by the CPUC Energy Division in calculating interim incentive payments, and intervenors' concerns about the fairness of the incentive structure. In this rulemaking the CPUC intends to adopt a new framework for the review of the remainder of 2006 – 2008 energy efficiency activities in a timeframe consistent with interim payments for 2008 no later than December 2009, and any final payments for 2006 – 2008 no later than December 2010. There is no assurance of earnings in any given year or that the mechanism will not be changed as a result of the rulemaking issued by the CPUC in January 2009.

2009 FERC Rate Case

In an order issued in September 2008, the FERC accepted and made effective on March 1, 2009, subject to refund and settlement procedures, SCE's proposed revisions to its tariff, filed in the 2009 transmission rate case. The revisions reflected changes to SCE's transmission revenue requirement and transmission rates, as discussed below.

SCE requested a $129 million increase in its retail transmission revenue requirements (or a 39% increase over the current retail transmission revenue requirement) due to an increase in transmission capital-related costs and increases in transmission operating and maintenance expenses that SCE expects to incur in 2009 to maintain grid reliability. The transmission revenue requirement request is based on a return on equity of 12.7%, which is composed of a 12.0% base ROE and 0.7% in transmission incentives previously approved by the FERC (see "— FERC Transmission Incentives" below for further information). SCE is unable to predict the revenue requirement that the FERC will ultimately authorize.

FERC Transmission Incentives

The Energy Policy Act of 2005 established incentive-based rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. Pursuant to this act, in November 2007, the FERC issued an order granting incentives on three of SCE's largest proposed transmission projects. These include 125 basis point ROE adders on SCE's proposed base ROE for SCE's DPV2 and Tehachapi transmission projects and a 75 basis point ROE adder for SCE's Rancho Vista Substation Project ("Rancho Vista").

In June 2007, the ACC denied the approval of the DPV2 project which resulted in an estimated two year delay of the project. SCE continues its efforts to obtain the regulatory approvals necessary to construct the DPV2 project and continues to evaluate its options, which include but are not limited to, filing a new application with the ACC and building the project in various phases.

The order also grants a 50 basis point ROE adder on SCE's cost of capital for its entire transmission rate base in SCE's next FERC transmission rate case for SCE's participation in the CAISO. In addition, the order on incentives permits SCE to include in rate base 100% of prudently-incurred capital expenditures during construction, also known as CWIP, of all three projects and 100% recovery of prudently-incurred abandoned plant costs for two of the projects, if either are cancelled due to factors beyond SCE's control.

In August 2008, the CPUC filed an appeal of the FERC incentives order at the DC Circuit Court of Appeals. The court issued a ruling on November 6, 2008, accepting the CPUC's request that the court refrain from ruling on the CPUC's appeal until a final FERC order is issued in the 2008 CWIP case (see "— FERC Construction Work in Progress Mechanism" below for further information).

FERC Construction Work in Progress Mechanism

FERC CWIP 2008

In February 2008, the FERC approved SCE's revision to its tariff to collect 100% of CWIP in rate base for its Tehachapi, DPV2, and Rancho Vista, as authorized by FERC in its transmission incentives order discussed above which resulted in an authorized base transmission revenue requirement of $45 million, subject to refund. In March 2008, the CPUC filed a petition for rehearing with the FERC on the FERC's acceptance of SCE's proposed ROE for CWIP and in another 2008 protest to an SCE compliance filing, requested an evidentiary hearing to be set to further review SCE's costs. SCE cannot predict the outcome of the matters in this proceeding.

FERC CWIP 2009

SCE filed its 2009 CWIP rate adjustment in October 2008 proposing a reduction to its CWIP revenue requirement from $45 million to $39 million to be effective on January 1, 2009. Several parties, including the CPUC, filed protests to the October filing in November 2008, primarily contesting SCE's proposed base ROE of 12.0%. The FERC issued an order in December 2008, allowing the proposed 2009 CWIP rates to go into effect on January 1, 2009, subject to refund, and directing that the 2009 CWIP ROE be made subject to the outcome of the pending 2008 FERC CWIP proceeding. The FERC also consolidated all issues other than ROE with SCE's 2009 FERC rate case proceeding (see "2009 FERC Rate Case" above for further information).

Energy Resource Recovery Account Proceedings

The ERRA is the balancing account mechanism that tracks and recovers SCE's fuel and procurement-related costs. SCE files annual forecasts of these costs that it expects to incur during the following year and sets rates using forecasts. At December 31, 2008, the ERRA was under-collected by $406 million, which was 7.6% of SCE's prior year's generation revenue. The CPUC has established a "trigger" mechanism that allows for a rate adjustment if the ERRA balancing account overcollection or undercollection exceeds 5% of SCE's prior year's generation revenue. Due to the recent decrease in natural gas prices, SCE estimates that the ERRA balancing account undercollection will be below the trigger threshold by June 2009. Therefore, SCE does not expect to file a trigger application.

2009 ERRA Revenue Requirements Forecast

On January 29, 2009, the CPUC approved SCE's proposal that an increase of $331 million over SCE's adopted 2008 ERRA revenue requirement be reflected in rate levels (which results in a 2009 ERRA revenue requirement of $4.0 billion). The adopted 2009 ERRA revenue requirement change will be implemented in rates on March 1, 2009. The CPUC further agreed to let SCE net a projected $110 million decrease in its 2009 procurement costs against the remaining under-collected ERRA balance in the future and rely on timely trigger applications for additional recovery needs.

Resource Adequacy Requirements

Under the CPUC's resource adequacy framework, all load-serving entities in California have an obligation to procure sufficient resources to meet their expected customers' needs on a system-wide basis with a 15 – 17% reserve level. In addition, on June 6, 2006, the CPUC adopted local resource adequacy requirements.

SCE is required to demonstrate every month that it has met 100% of its system resource adequacy requirement one month in advance of expected need (known as the month-ahead system resource adequacy showing). SCE is also required to make its year-ahead system resource adequacy showing (90% threshold) in the fall of the calendar year prior to the compliance year. The system resource adequacy requirements provide for penalties of 300% of the cost of new monthly capacity for failing to meet the system resource adequacy requirements. Under the local resource adequacy requirements, SCE must demonstrate on an annual basis that it has procured 100% of its requirement within defined local areas. The local resource adequacy requirements provide for penalties of 100% of the cost of new monthly capacity for failing to meet the local resource adequacy requirements. SCE demonstrated its compliance with the resource adequacy requirements in 2008, expects to be in compliance in 2009 and does not expect to incur any resource adequacy program penalties.

Peaker Plant Generation Projects

In August 2006, the CPUC issued a ruling addressing electric reliability needs in Southern California for summer 2007 that directed SCE, among other things, to pursue new utility-owned peaker generation that would be online by August 2007. In response, SCE pursued development of five combustion turbine peaker plants, four of which were placed online in August 2007 to help meet peak customer demands and other system requirements. In its cost recovery application for the four constructed peaker plants, SCE will revise the total recorded costs as of the end of 2008, to approximately $263 million. SCE also proposed to continue tracking the capital costs of a fifth peaker plant in the interim cost tracking mechanism approved by the CPUC and used during the construction period. Additionally, SCE proposed to file a separate cost recovery application for the fifth peaker after it is installed or its final disposition is otherwise determined (see below for further discussion on the status of the fifth peaker plant). Several parties have filed protests or other filings in response to SCE's cost recovery application. SCE expects to fully recover its costs from these peaker plants, but cannot predict the outcome of regulatory proceedings. SCE expects a CPUC decision on its cost recovery application for the first four peaker plants in 2009.

SCE has continued to pursue the construction of the fifth peaker plant. As of December 31, 2008, SCE has incurred capital costs of approximately $39 million for the fifth peaker, primarily for the purchase of the major piece of capital equipment, the combustion turbine. The required development permit for the fifth peaker plant was denied by the City of Oxnard in July 2007 and SCE appealed the denial to the California Coastal Commission. The Commission heard SCE's appeal on August 6, 2008, but did not reach a final decision. SCE expects the matter to be heard again by April 2009 but cannot predict the outcome of the appeal. SCE expects to fully recover its costs for the fifth peaker plant.

Procurement of Renewable Resources

California law requires SCE to increase its procurement of renewable resources by at least 1% of its annual retail electricity sales per year so that 20% of its annual electricity sales are procured from renewable resources by no later than December 31, 2010.

It is unlikely that SCE will have 20% of its annual electricity sales procured from renewable resources by 2010. However, SCE may still meet the 20% target by utilizing the flexible compliance rules, such as banking of past surplus and earmarking of future deliveries from executed contracts. SCE continues to engage in several renewable procurement activities including formal solicitations approved by the CPUC, bilateral negotiations with individual projects and other initiatives.

Under current CPUC decisions, potential penalties for SCE's inability to achieve its renewable procurement objectives for any year will be considered by the CPUC in the context of the CPUC's review of SCE's annual compliance filing. Under the CPUC's current rules, the maximum penalty for inability to achieve renewable procurement targets is $25 million per year. SCE does not believe it will be assessed penalties for 2008 or the prior years and cannot predict whether it will be assessed penalties for future years.

Mohave Generating Station and Related Proceedings

Mohave obtained all of its coal supply from the Black Mesa Mine in northeast Arizona, located on lands of the Tribes. This coal was delivered from the mine to Mohave by means of a coal slurry pipeline, which required water from wells located on lands belonging to the Tribes in the mine vicinity. Uncertainty over post-2005 coal and water supply prevented SCE and other Mohave co-owners from making approximately $1.1 billion in Mohave-related investments (SCE's share is $605 million), including the installation of enhanced pollution-control equipment required by a 1999 air-quality consent decree in order for Mohave to operate beyond 2005. Accordingly, the plant ceased operations, as scheduled, on December 31, 2005, consistent with the provisions of the consent decree, and there are no plans for the co-owners to return the plant to service.

The co-owners are continuing to evaluate the range of options for disposition of the plant, which conceivably could include, among other potential options, sale of the plant to a power plant operator, decommissioning of the plant and sale of the property, decommissioning and apportionment of the land among the owners, or developing in conjunction with some or all of the co-owners a renewable energy facility at the property.

SCE believed it was in full compliance with CPUC requirements and as of December 31, 2008, SCE had a Mohave net regulatory asset of approximately $54 million representing its net unamortized coal plant investment, partially offset by revenue collected for future removal costs. Based on a CPUC decision, SCE is allowed to continue to earn its authorized rate of return on the Mohave investment and receive rate recovery for amortization, costs of removal, and operating and maintenance expenses, subject to balancing account treatment. On October 5, 2006, SCE submitted a formal notification to the CPUC regarding the out-of-service status of Mohave. The CPUC may institute an investigation to determine whether to reduce SCE's rates in light of Mohave's changed status. At this time, SCE does not anticipate that the CPUC will order a rate reduction. However, SCE cannot predict the outcome of any future CPUC action.

ISO Disputed Charges

On April 20, 2004, the FERC issued an order concerning a dispute between the ISO and the Cities of Anaheim, Azusa, Banning, Colton and Riverside, California over the proper allocation and characterization of certain transmission service related charges. The potential cost to SCE of the FERC order, net of amounts SCE expects to receive through the PX, SCE's scheduling coordinator at the pertinent time, is estimated to be approximately $20 million to $25 million, including interest. The order has been the subject of continuing legal proceedings since it was issued. SCE believes that the most recent substantive order FERC has issued in the proceedings correctly allocates responsibility for these ISO charges. However, SCE cannot predict the final outcome of the rehearing. If a subsequent regulatory decision changes the allocation of responsibility for these charges, and SCE is required to pay these charges as a transmission owner, SCE may seek recovery in its reliability service rates. SCE cannot predict whether recovery of these charges in its reliability service rates would be permitted.

Market Redesign and Technology Upgrade

In early 2006, the ISO began a program to redesign and upgrade the wholesale energy market across ISO's controlled grid, known as the MRTU. The programs under the MRTU initiative are designed to implement market improvements to assure grid reliability, more efficient and cost-effective use of resources, and to create technology upgrades that would strengthen the entire ISO computer system. The CAISO has targeted the MRTU market to be operational March 31, 2009, subject to certain conditions, and filed a readiness application with the FERC in January 2009. See "SCE: Market Risk Exposures — Commodity Price Risk — Market Redesign and Technology Upgrade" for further discussion.

SCE: OTHER DEVELOPMENTS

Palo Verde Nuclear Generating Station Inspection

The NRC held three special inspections of Palo Verde, between March 2005 and February 2007. The combination of the results of the first and third special inspections caused the NRC to undertake an additional oversight inspection of Palo Verde. This additional inspection, known as a supplemental inspection, was completed in December 2007. In addition, Palo Verde was required to take additional corrective actions based on the outcome of completed surveys of its plant personnel and self-assessments of its programs and procedures. The NRC and APS defined and agreed to inspection and survey corrective actions that the NRC embodied in a Confirmatory Action Letter, which was issued in February 2008. APS is presently on track to complete the corrective actions required to close the Confirmatory Action Letter by mid-2009. Palo Verde operation and maintenance costs (including overhead) increased in 2007 by approximately $7 million from 2006. SCE estimates that operation and maintenance costs will increase by approximately $23 million (in 2007 dollars) over the two year period 2008 – 2009, from 2007 recorded costs including overhead costs. In the 2009 GRC, SCE requested recovery of, and two-way balancing account treatment for, Palo Verde operation and maintenance expenses including costs associated with these corrective actions. If approved, this would provide for recovery of these costs over the three-year GRC cycle (see "SCE: Regulatory Matters — Current Regulatory Developments — 2009 General Rate Case Proceeding" above for more information).

Navajo Nation Litigation

The Navajo Nation filed a complaint in June 1999 in the District Court against SCE, among other defendants, arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal RICO statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentations by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal supplied to Mohave. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion. In March 2001, the Hopi Tribe was permitted to intervene as an additional plaintiff but has not yet identified a specific amount of damages claimed. The case was stayed at the request of the parties in October 2004, but was reinstated to the active calendar in March 2008.

A related case against the U.S. Government is presently before the U.S. Supreme Court. The outcome of that case could affect the Navajo Nation's pursuit of claims against SCE. A decision from the U.S. Supreme Court is expected in mid-2009.

SCE cannot predict the outcome of the Tribe's complaints against SCE or the ultimate impact on these complaints of the on-going litigation by the Navajo Nation against the U.S. Government in the related case.

Spent Nuclear Fuel

Under federal law, the DOE is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE did not meet its contractual obligation to begin acceptance of spent nuclear fuel by January 31, 1998. It is not certain when the DOE will begin accepting spent nuclear fuel from San Onofre or other nuclear power plants. Extended delays by the DOE have led to the construction of costly alternatives and associated siting and environmental issues. SCE has paid the DOE the required one-time fee applicable to nuclear generation at San Onofre (approximately $24 million, plus interest). SCE has also been paying a required quarterly fee equal to 0.1¢ per-kWh of nuclear-generated electricity sold after April 6, 1983. On January 29, 2004, SCE, as operating agent, filed a complaint against the DOE in the United States Court of Federal Claims seeking damages for the DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre.

SCE has primary responsibility for the interim storage of spent nuclear fuel generated at San Onofre. Such interim storage for San Onofre is on-site.

APS, as operating agent, has primary responsibility for the interim storage of spent nuclear fuel at Palo Verde. Palo Verde plans to add storage capacity incrementally to maintain full core off-load capability for all three units. In order to increase on-site storage capacity and maintain core off-load capability, Palo Verde has constructed an independent spent fuel storage facility.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to the amount of available financial protection, which is currently approximately $12.5 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($300 million). The balance is covered by the industry's retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the United States results in claims and/or costs which exceed the primary insurance at that plant site.

Federal regulations require this secondary level of financial protection. The NRC exempted San Onofre Unit 1 from this secondary level, effective June 1994. Beginning October 29, 2008, the maximum deferred premium for each nuclear incident is approximately $118 million per reactor, but not more than approximately $18 million per reactor may be charged in any one year for each incident. The maximum deferred premium per reactor and the yearly assessment per reactor for each nuclear incident is adjusted for inflation at least once every five years. The most recent inflation adjustment took effect on October 29, 2008. Based on its ownership interests, SCE could be required to pay a maximum of approximately $235 million per nuclear incident. However, it would have to pay no more than approximately $35 million per incident in any one year. Such amounts include a 5% surcharge if additional funds are needed to satisfy public liability claims and are subject to adjustment for inflation. If the public liability limit above is insufficient, federal law contemplates that additional funds may be appropriated by Congress. This could include an additional assessment on all licensed reactor operators as a measure for raising further electric utility revenue.

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. A mutual insurance company owned by utilities with nuclear facilities issues these policies. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to approximately $45 million per year. Insurance premiums are charged to operating expense.

Wildfire Insurance Issues

Recent, severe wildfires in California have given rise to very large damage claims against California utilities. Additionally, California law includes a doctrine of inverse condemnation that imposes strict liability (including liability for a claimant's attorneys' fees) for fire damage caused to private property by SCE's electric facilities that serve the public. SCE currently is insured for such liabilities up to a limit of $650 million (with a $2 million self-insured retention) until September 2009. The strict liability standard and the apparent rising trend in wildfire occurrences and intensity may affect SCE's ability to obtain comparable insurance levels at comparable cost in the future, and there can be no assurance that SCE would be allowed to recover in customer rates the increased cost of such insurance or the cost of any uninsured losses. In addition, the CPUC investigates fires that may have been caused by a utility's facilities, and, if violations of CPUC regulations are found, the CPUC may penalize the utility.

Federal and State Income Taxes

Edison International files its federal income tax returns on a consolidated basis and files on a combined basis in California and certain other states. SCE is included in the consolidated federal and state combined income tax returns. See "Other Developments — Federal and State Income Taxes" for further discussion of these matters.

SCE: LIQUIDITY

Overview

As of December 31, 2008, SCE had cash and equivalents of $1.6 billion ($89 million of which was held by SCE's consolidated VIEs). As a reaction to significant disruption in the credit and capital markets, SCE borrowed against its credit facility and issued bonds in October 2008 to ensure the availability of funds to meet its future cash requirements. The proceeds were invested in U.S. treasury bills and U.S. treasury and government agency money market funds. This credit line draw is recorded as short-term debt, as it is expected to be re-paid by year-end 2009.

In March 2008, SCE amended its existing $2.5 billion credit facility, extending the maturity to February 2013 while retaining existing borrowing costs as specified in the facility. The amendment also provides four extension options which, if all exercised, and agreed to by the lenders, will result in a final termination in February 2017. During February 2009, SCE has been negotiating with several banks to potentially increase its liquidity facilities by an additional $500 million. The consummation of such negotiations is subject to the availability of additional bank credit capacity on commercially feasible terms. Such liquidity would be used to address potential requirements of SCE's ongoing procurement-related needs.

A subsidiary of Lehman Brothers Holdings, Lehman Brothers Bank, FSB, is one of the lenders in SCE's credit agreement representing a total commitment of $106 million. Lehman Brothers Bank, FSB, had funded $25 million of a borrowing request during the second quarter of 2008. On September 15, 2008, Lehman Brothers Holdings filed for protection under Chapter 11 of the U.S. Bankruptcy Code. Lehman Brothers Bank, FSB, declined requests for funding of approximately $57 million during the second half of 2008.

The following table summarizes the status of the SCE credit facility at December 31, 2008:

In millions	SCE
Commitment	$ 2,500
Less: Unfunded commitment from Lehman Brothers subsidiary	(81)
	2,419
Outstanding borrowings	(1,893)
Outstanding letters of credit	(141)
Amount available	**$ 385**

As of December 31, 2008, SCE's long-term debt, including current maturities of long-term debt, was $6.4 billion. In October 2008, SCE issued $500 million of 5.75% first and refunding mortgage bonds due in 2014.

SCE's estimated cash outflows during the 12-month period following December 31, 2008 are expected to consist of:

- Projected capital expenditures primarily to replace and expand distribution and transmission infrastructure and construct and replace major components of generation assets (see "— Capital Expenditures" below);
- Fuel and procurement-related costs (see "SCE: Regulatory Matters — Current Regulatory Developments — Energy Resource Recovery Account Proceedings"), including collateral requirements (see "— Margin and Collateral Deposits");
- In December 2008 the Board of Directors of SCE declared a $100 million dividend to Edison International which was paid in January 2009. As a result of SCE's cash requirements, including its capital expenditures plan, SCE does not expect to declare additional dividends to Edison International in 2009;
- Maturity and interest payments on short- and long-term debt outstanding;
- General operating expenses; and
- Pension and PBOP trust contributions (see "— Pension and PBOP trusts" below).

As discussed above, SCE expects to meet its 2009 continuing obligations, including cash outflows for operating expenses and power-procurement, through cash and equivalents on hand and operating cash flows. Projected 2009 capital expenditures are expected to be financed through cash and equivalents on hand, operating cash flows and incremental capital market financings of debt and preferred equity. SCE expects that it would also be able to draw on the remaining availability of its credit facility and access capital markets if additional funding and liquidity is necessary to meet the estimated operating and capital requirements, but given current market conditions there can be no assurance of such credit and capital availability.

On February 13, 2008, President Bush signed the Economic Stimulus Act of 2008 (2008 Stimulus Act). The 2008 Stimulus Act includes a provision that provides accelerated bonus depreciation for certain capital expenditures incurred during 2008. Edison International expects that certain capital expenditures incurred by SCE during 2008 will qualify for this accelerated bonus depreciation, which would provide additional cash flow benefits estimated to be approximately $110 million for the 2008 tax return. On February 17, 2009, President Obama signed the American Recovery and Reinvestment Act of 2009 which extended the accelerated bonus depreciation provision through the end of 2009. Edison International expects that certain capital expenditures incurred by SCE during 2009 will qualify for this accelerated bonus depreciation.

SCE's liquidity may be affected by, among other things, matters described in "SCE: Regulatory Matters" and "Commitments, Guarantees and Indemnities."

Capital Expenditures

SCE has planned capital expenditures to replace and expand its distribution and transmission infrastructure, and to construct and replace generation assets. As previously discussed, the CPUC has issued an Administrative Law Judge's proposed decision, as well as a revised alternate proposed decision on SCE's 2009 GRC. The two proposed decisions provide for different levels of capital expenditures. Based on the revised alternate proposed decision and reflecting a level of variability (discussed below), SCE's 2009 through 2013 capital investment plan includes capital spending in the range of $17.1 billion to $21 billion. The Administrative Law Judge's proposed decision, if adopted, would further reduce the range of capital spending by approximately $2.8 billion related to a $2.0 billion modeling error which authorizes a specified level of capital expenditures, but does not provide the revenue requirement to recover a portion of these capital expenditures beginning in 2010 and an $800 million reduction in the level of capital expenditures. Recovery of the CPUC jurisdictional 2009 through 2011 planned expenditures primarily is subject to CPUC approval in SCE's 2009 GRC application. Recovery of certain other projects included in the 2009 through 2011 investment plan has been approved or will be requested and approved through other CPUC-authorized mechanisms on a project-by-project basis. These projects include, among others, SCE's SmartConnect advanced metering infrastructure project, the San Onofre steam generator replacement project, and the solar photovoltaic program. SCE plans total investments for 2009 through 2013 to be $1.2 billion, $450 million and $880 million, for each of these projects, respectively. SCE's GRC related expenditures for 2012 and 2013 are subject to future approval. Recovery of the 2009 through 2013 planned transmission expenditures for FERC-jurisdictional projects have been requested in the 2009 FERC Rate Case proceeding, or will be requested in future transmission filings with the FERC.

SCE's 2008 capital expenditures (including accruals) were $2.4 billion related to its 2008 capital plan. SCE's 2008 capital expenditures were less than the forecast for 2008 of $2.9 billion, primarily due to delays in transmission investments as well as other timing delays. Developments in the financial markets, regulatory decisions, and economic conditions in the U.S. may also alter SCE's future capital expenditures plans. See "Edison International: Management Overview — Areas of Business Focus — Financial Markets and Economic Conditions" for further discussion. The completion of the projects, the timing of expenditures, and the associated recovery may be affected by permitting requirements and delays, construction delays, availability of labor, equipment and materials, financing, legal and regulatory developments, weather and other unforeseen conditions. The estimated capital expenditures for the next five years may vary from SCE's current forecast. If SCE assumes the same level of variability to forecast experienced in 2008 (approximately 18%), SCE's 2009 forecast would vary in the range of $2.9 billion to $3.6 billion. If the Administrative Law Judge's proposed decision is adopted, the 2009 forecast would be reduced by approximately $800 million resulting from a $600 million modeling error and a $200 million reduction in the level of capital expenditures, both discussed above.

Included in SCE's capital investment plan are projected environmental capital expenditures of $476 million in 2009 and approximately $2.1 billion for the period 2010 through 2013. The projected environmental capital expenditures are mainly for undergrounding certain transmission and distribution lines at SCE.

Solar Photovoltaic Program

On March 27, 2008, SCE filed an application with the CPUC to implement its Solar Photovoltaic (PV) Program to develop up to 250 MW of utility-owned Solar PV generating facilities ranging in size from 1 to 2 MW each on commercial and industrial rooftop space in SCE's service territory. Subject to CPUC approval, the capital expenditures will be eligible to be included in SCE's earning asset base if the actual costs of the program are equal to or lower than the reasonableness threshold amount of $963 million in nominal dollars. SCE also proposes to apply a CPUC-established 100 basis point incentive adder to SCE's allowed rate of return on rate base on the project. In September 2008, the CPUC granted SCE's request to track costs spent on projects up to $25 million incurred prior to the receipt of the CPUC's final decision in a memorandum account for potential future recovery. SCE has spent $12 million as of December 31, 2008. SCE completed its first 2 MW project in December 2008, and expects to continue to move forward with two other projects in advance of the final CPUC decision subject to the authorized tracking account mechanism. In September 2008, several parties filed testimony opposing SCE's Solar PV program application. Evidentiary hearings took place in November 2008 and a final decision is expected in March 2009. SCE cannot predict the final outcome of this proceeding.

EdisonSmartConnect™

SCE's EdisonSmartConnect™ project involves installing state-of-the-art "smart" meters in approximately 5.3 million households and small businesses through its service territory. The development of this advanced metering infrastructure is expected to be accomplished in three phases: the initial design phase to develop the new generation of advanced metering systems (Phase I), which was completed in 2006; the pre-deployment phase (Phase II) to field test and select EdisonSmartConnect™ technologies, select the deployment vendor and finalize the EdisonSmartConnect™ business case for full deployment, which was completed in December 2007; and the final deployment phase (Phase III), to deploy meters to all residential and small business customers under 200 kW over a five-year period. SCE applied to the CPUC in July 2007 to request authority to deploy the program and began deployment activities in 2008. In March 2008, SCE reached a full settlement of the Phase III issues with the DRA and in September 2008, the CPUC approved the settlement, authorizing SCE to recover $1.63 billion in ratepayer funding for the Phase III deployment of EdisonSmartConnect™. SCE expects to begin deployment of meters in 2009, and anticipates completion of the deployment in 2012. The total cost for this project, including Phase II pre-deployment, is estimated to be $1.7 billion of which $1.25 billion is estimated to be capitalized and included in utility rate base. The remaining book value for SCE's existing meters at December 31, 2008 is $398 million. SCE expects to recover the remaining book value of the existing meters, with a return, over their remaining lives through its 2009 GRC application.

Pension and PBOP Trusts

Volatile market conditions have affected the value of SCE's trusts established to fund its future long-term pension benefits and other postretirement benefits. The fair value of the investments (reflecting investment performance, contributions and benefit payments) within the pension and PBOP plan trusts declined 35% and 33%, respectively, during 2008. These benefit plan assets and related obligations are remeasured annually using a December 31 measurement date. The plans' funded status is recorded on the balance sheet in accordance with SFAS No. 158. Due to the reductions in the value of plan assets, the pension and PBOP plans were underfunded $937 million and $1 billion at December 31, 2008, respectively. Forecast expense in 2009 and contributions for the 2009 plan year are expected to increase by approximately $150 million. SCE is authorized to recover these costs through customer rates, therefore recognition of the funded status of SCE's plans is offset by regulatory assets of $1.9 billion. In the 2009 GRC, SCE requested continued balancing account treatment for amounts contributed to these trusts and requested that these amounts be collected annually (see "SCE: Regulatory Matters — Current Regulatory Developments — 2009 General Rate Case Proceeding" for further discussion). In response to the volatile market conditions, the trusts' investment committees have implemented interim lower equity allocation targets and continue to assess the long-term asset allocation strategies. The Pension Protection Act of 2006 established minimum funding standards and restricts plan payouts if underfunded by more than 20%, limiting provisions for lump-sum distributions and adopting amendments that increase plan liabilities.

Nuclear Decommissioning Trusts

Volatile market conditions have also affected the value of SCE's trusts established to fund nuclear decommissioning obligations. SCE is collecting in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. Funds collected, together with accumulated earnings, will be utilized solely for decommissioning.

Nuclear decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately $46 million per year. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. The next filing is in April 2009 for contribution changes in 2011. The significant decrease recently experienced in the nuclear decommissioning trust assets, is expected, absent a market recovery, to impact the CPUC established contributions for 2011. In response to the volatile market conditions, the trusts' investment committees have implemented interim lower equity allocation targets and continue to assess the long-term asset allocation strategies. See "Critical Accounting Estimates and Policies — Nuclear Decommissioning" for further information.

Trust investments (at fair value) are as follows:

In millions	Maturity Dates	December 31, 2008	December 31, 2007
Municipal bonds	2009 – 2044	**$ 629**	$ 561
Stocks	–	**1,308**	1,968
United States government issues	2009 – 2049	**304**	552
Corporate bonds	2009 – 2047	**260**	241
Short-term investments, primarily cash equivalents	2009	**23**	56
Total		**$ 2,524**	$ 3,378

Note: Maturity dates as of December 31, 2008.

The following table sets forth a summary of changes in the fair value of the trust for December 31, 2008:

In millions	December 31, 2008
Balance at beginning of period	$ 3,378
Realized losses – net	(65)
Unrealized losses – net	(545)
Other-than-temporary impairment	(317)
Earnings and other	73
Balance at December 31, 2008	**$ 2,524**

Credit Ratings

At December 31, 2008, SCE's credit ratings were as follows:

	Moody's Rating	S&P Rating	Fitch Rating
Long-term senior secured debt	A2	A	A+
Short-term (commercial paper)	P-2	A-2	F-1

The above SCE credit ratings have remained unchanged since year-end 2007. SCE cannot provide assurance that its current credit ratings will remain in effect for any given period of time or that one or more of these ratings will not be changed. These credit ratings are not recommendations to buy, sell or hold its securities and may be revised at any time by a rating agency.

Dividend Restrictions and Debt Covenants

The CPUC regulates SCE's capital structure and limits the dividends it may pay Edison International. In SCE's most recent cost of capital proceeding, the CPUC sets an authorized capital structure for SCE which included a common equity component of 48%. SCE may make distributions to Edison International as long as the common equity component of SCE's capital structure remains at or above the authorized level on a 13-month weighted average basis of 48%. At December 31, 2008, SCE's 13-month weighted-average common equity component of total capitalization was 50.6% resulting in the capacity to pay $345 million in additional dividends.

SCE has a debt covenant in its credit facility that requires a debt to total capitalization ratio of less than or equal to 0.65 to 1 to be met. At December 31, 2008, SCE's debt to total capitalization ratio was 0.53 to 1.

Margin and Collateral Deposits

SCE has entered into certain margining agreements for power and natural gas trading activities in support of its procurement plan as approved by the CPUC. SCE's margin deposit requirements under these agreements can vary depending upon the level of unsecured credit extended by counterparties and brokers, changes in market prices relative to contractual commitments, and other factors. Future collateral requirements may be higher (or lower) than collateral requirements at December 31, 2008, due to the addition of incremental power and energy procurement contracts with margining agreements, if any, and the impact of changes in wholesale power and natural gas prices on SCE's contractual obligations.

Certain requirements to post cash and/or collateral (primarily for changes in fair value and accounts payables on delivered energy transactions) would be triggered if SCE's credit ratings were downgraded to below investment grade, as indicated in the table below.

In millions	
Collateral posted as of December 31, 2008[(1)]	$ 230
Incremental collateral requirements resulting from a potential downgrade of SCE's credit rating to below investment grade	186
Total posted and potential collateral requirements[(2)]	**$ 416**

(1) Collateral posted consisted of $72 million which were offset against net derivative liabilities in accordance with the implementation of FIN 39-1, and $158 million provided to counterparties and other brokers (consisting of $17 million in cash reflected in "Margin and collateral deposits" on the consolidated balance sheets and $141 million in letters of credit).

(2) Total posted and potential collateral requirements may increase by an additional $124 million, based on SCE's forward position as of December 31, 2008, due to adverse market price movements over the remaining life of the existing contracts using a 95% confidence level.

SCE's incremental collateral requirements are expected to be met from liquidity available from cash on hand and available capacity under SCE's $2.5 billion credit facility, discussed above.

SCE: MARKET RISK EXPOSURES

SCE's primary market risks include fluctuations in interest rates, commodity prices and volumes, and counterparty credit. Fluctuations in interest rates can affect earnings and cash flows. Fluctuations in commodity prices and volumes and counterparty credit losses may temporarily affect cash flows, but are not expected to affect earnings due to expected recovery through regulatory mechanisms. SCE uses derivative financial instruments, as appropriate, to manage its market risks.

Interest Rate Risk

SCE is exposed to changes in interest rates primarily as a result of its borrowing and investing activities used for liquidity purposes, to fund business operations and to finance capital expenditures. The nature and amount of SCE's long-term and short-term debt can be expected to vary as a result of future business requirements, market conditions and other factors. In addition, SCE's authorized return on common equity (11.5% for 2009 and 2008 and 11.6% for 2007), which is established in SCE's cost of capital proceeding, is set on the basis of forecasts of interest rates and other factors. Variances in actual financing costs compared to authorized financing costs either positively or negatively impact earnings. See "SCE: Regulatory Matters — Base Rates" for further discussion on SCE's recoverability of financing costs.

At December 31, 2008, SCE did not believe that its short-term debt was subject to interest rate risk, due to the fair market value being approximately equal to the carrying value. At December 31, 2008, the fair market value of SCE's long-term debt (including long-term debt due within one year) was $6.7 billion, compared to a carrying value of $6.4 billion. A 10% increase in market interest rates would have resulted in a $336 million decrease in the fair market value of SCE's long-term debt. A 10% decrease in market interest rates would have resulted in a $368 million increase in the fair market value of SCE's long-term debt.

In July 2007, SCE entered into interest rate-locks to mitigate interest rate risk associated with future financings. Due to declining interest rates in late 2007, at December 31, 2007, these interest rate locks had unrealized losses of $33 million. In January and February 2008, SCE settled these interest rate-locks resulting in realized losses of $33 million. A related regulatory asset was recorded in this amount and SCE will amortize and recover this amount as interest expense associated with its series 2008A and 2008B financings issued in January and August 2008.

Commodity Price Risk

Introduction

SCE is exposed to commodity price risk from its purchases of additional capacity and ancillary services to meet peak energy requirements and from exposure to natural gas prices that affect costs associated with power purchased from QFs, fuel tolling arrangements, and its own gas-fired generation, including SCE's Mountainview plant. Contract energy prices for most nonrenewable QFs are based in large part on the monthly southern California border price of natural gas. In addition to the QF contracts, SCE has power contracts in which SCE has agreed to provide the natural gas needed for generation under those power contracts, which are referred to as tolling arrangements. In addition to SCE's Mountainview and peaker plants, approximately 46% of SCE's power purchase requirements are subject to natural gas price volatility.

The CPUC has established resource adequacy requirements which require SCE to acquire and demonstrate enough generating capacity in its portfolio for a planning reserve margin of 15 – 17% above its peak load as forecast for an average year (see "SCE: Regulatory Matters — Current Regulatory Developments — Resource Adequacy Requirements"). The establishment of a sufficient planning reserve margin mitigates, to some extent, exposure to commodity price risk for spot market purchases.

SCE's purchased-power costs and gas expenses, as well as related hedging costs, are recovered through the ERRA. To the extent SCE conducts its power and gas procurement activities in accordance with its CPUC-authorized procurement plan, California statute (Assembly Bill 57) establishes that SCE is entitled to full cost recovery. As a result of these regulatory mechanisms, changes in energy prices may impact SCE's cash flows but are not expected to affect earnings. Certain SCE activities, such as contract administration, SCE's duties as the CDWR's limited agent for allocated CDWR contracts, and portfolio dispatch are reviewed annually by the CPUC for reasonableness. The CPUC has currently established a maximum disallowance cap of $37 million for these activities.

In accordance with CPUC decisions, SCE, as the CDWR's limited agent, performs certain services for CDWR contracts allocated to SCE by the CPUC, including arranging for natural gas supply. Financial and legal responsibility for the allocated contracts remains with the CDWR. The CDWR, through coordination with SCE, has hedged a portion of its expected natural gas requirements for the gas tolling contracts allocated to SCE. Increases in gas prices over time, however, will increase the CDWR's gas costs. California state law permits the CDWR to recover its actual costs through rates established by the CPUC. This would affect rates charged to SCE's customers, but would not affect SCE's earnings or cash flows. As discussed under the heading, "SCE: Regulatory Matters — Current Regulatory Developments — Impact of Regulatory Matters on Customer Rates," if the existing CDWR power contracts, which have related natural gas supply contracts, are novated or replaced and SCE becomes a party to such contracts, SCE may have additional exposure to a rise in gas prices. SCE is currently unable to predict which or how many existing CDWR contracts will be novated or replaced. However, due to the expected recovery through regulatory mechanisms these power procurement expenses are not expected to affect earnings.

Natural Gas and Electricity Price Risk

SCE has an active hedging program in place to minimize ratepayer exposure to spot-market price spikes; however, to the extent that SCE does not mitigate the exposure to commodity price risk, the unhedged portion is subject to the risks and benefits of spot-market price movements, which are ultimately passed-through to ratepayers.

To mitigate SCE's exposure to spot-market prices, SCE enters into energy options, tolling arrangements, forward physical contracts and transmission congestion rights (FTRs and CRRs). SCE also enters into contracts for power and gas options, as well as swaps and futures, in order to mitigate its exposure to increases in natural gas and electricity pricing. These transactions are pre-approved by the CPUC or executed in compliance with CPUC-approved procurement plans.

SCE records its derivative instruments on its consolidated balance sheets at fair value unless they meet the definition of a normal purchase or sale. The derivative instrument fair values are marked to market at each reporting period. Any fair value changes are expected to be recovered from or refunded to customers through regulatory mechanisms and therefore, SCE's fair value changes have no impact on purchased-power expense or earnings. Hedge accounting is not used for these transactions due to this regulatory accounting treatment.

The following table summarizes the fair values of outstanding derivative financial instruments used at SCE to mitigate its exposure to spot market prices:

	December 31, 2008		**December 31, 2007**	
In millions	**Assets**	**Liabilities**	**Assets**	**Liabilities**
Electricity options, swaps and forward arrangements	**$ 7**	**$ 15**	$ 13	$ 57
Gas options, swaps and forward arrangements	**80**	**305**	46	22
Firm transmission rights and congestion revenue rights[(1)]	**81**	**—**	22	—
Tolling arrangements[(2)]	**63**	**647**	—	—
Netting and collateral	**—**	**(72)**	—	(2)
Total	**$ 231**	**$ 895**	$ 81	$ 77

(1) During the first quarter of 2008, the ISO held an auction for firm transmission rights. SCE participated in the ISO auction and paid $62 million to secure firm transmission rights for the period April 2008 through March 2009. The firm transmission rights will be replaced with CRRs in the MRTU environment. See "— Market Redesign and Technology Upgrade" below for further discussion. SCE recognized the firm transmission rights at fair value. SCE anticipates amounts paid for firm transmission rights that will no longer be valid in the MRTU environment will be refunded to SCE and has recognized this amount as a receivable from the ISO.

In September 2007 and November 2008, the CAISO allocated CRRs for the period April 2009 through December 2017 based on its expected generation flows. In addition, during the fourth quarter of 2008 SCE participated in a CAISO auction for the procurement of additional CRRs. The CRRs meet the definition of a derivative under SFAS No. 133. In accordance with SFAS No. 157, SCE recognized the CRRs at a $73 million fair value for the short term portion. SCE recorded liquidity reserves against the long-term CRRs fair values since there were no quoted long-term market prices for the CRRs and insufficient evidence of long-term market prices.

(2) In compliance with a CPUC mandate, SCE held an open, competitive solicitation that produced agreements with different project developers who have agreed to construct new, state-of-the-art Southern California generating resources. SCE has entered into a number of contracts, of which five received regulatory approval in the fourth quarter of 2008 and are recorded as financial derivatives. The contracts provide for fixed capacity payments as well as fixed pricing for energy delivered. The mark to market unrealized loss associated with the agreements are due to the decrease in forward gas market prices.

A 10% increase in electricity prices at December 31, 2008 would increase the fair value of electricity options, swaps and forward arrangements by approximately $39 million; a 10% decrease in electricity prices at December 31, 2008, would decrease the fair value by approximately $38 million. A 10% increase in electricity prices at December 31, 2008 would increase the fair value of tolling arrangements by approximately $293 million; a 10% decrease in electricity prices at December 31, 2008, would decrease the fair value by approximately $96 million. A 10% increase in gas prices at December 31, 2008 would increase the fair value of gas options, swaps and forward arrangements by approximately $101 million; a 10% decrease in gas prices at December 31, 2008, would decrease the fair value by approximately $112 million. A 10% increase in electricity prices at December 31, 2008 would decrease the fair value of firm transmission rights and congestion revenue rights by approximately $3 million; a 10% decrease in electricity prices at December 31, 2008, would decrease the fair value by approximately $3 million.

SCE's realized gains and losses arising from derivative instruments are reflected in purchased-power expense and are recovered through the ERRA mechanism. Unrealized gains and losses have no impact on purchased-power expense due to regulatory mechanisms. As a result, realized and unrealized gains and losses do not affect earnings, but may temporarily affect cash flows. Realized losses on economic hedging were $60 million in 2008, $132 million in 2007, and $339 million in 2006. Unrealized (gains) losses on economic hedging were $638 million in 2008, $(94) million in 2007, and $237 million in 2006. Changes in realized and unrealized gains and losses on economic hedging activities were primarily due to significant decreases in forward natural gas prices in 2008 compared to 2007. Changes in realized and unrealized gains and losses on economic hedging activities in 2007 compared to 2006 were primarily due to changes in SCE's gas hedge portfolio mix as well as an increase in the natural gas futures market in 2007.

Market Redesign and Technology Upgrade

As previously discussed in "SCE: Regulatory Matters — Current Regulatory Developments — Market Redesign and Technology Upgrade," the CAISO has targeted the MRTU market to be operational on March 31, 2009, subject to certain conditions. The MRTU market design allows the CAISO to conduct a day-ahead market that combines energy, ancillary services and congestion management. By starting this process in the day-ahead time frame, there is less reliance on the more volatile hour-ahead and real-time markets.

The new MRTU market will provide day-ahead and real-time markets using Nodal Locational Marginal Prices, eliminating the current zonal environment. The impact of MRTU on SCE is primarily driven by this transition from zonal to nodal prices as well as the introduction of a central day-ahead energy market operated by CAISO. The nodal prices will provide enhanced transparency of market prices throughout the CAISO control area, but it may also make forecasting prices more challenging due to the complexity and data intensity that CAISO uses to calculate energy prices. The introduction of the day-ahead market (known as the Integrated

Forward Market or IFM) will change the way SCE manages its portfolio: rather than matching supply and demand resources before submitting energy schedules to CAISO as is done today, under MRTU SCE will need to bid its generation and load requirements into the IFM. In essence, SCE will sell its generation from its utility-owned generation assets and existing power procurement contracts through IFM and buy its load requirements from IFM. SCE will bid its generation at nodes near the source of the generation, but will take delivery at nodes throughout SCE's service territory. Congestion may occur due to transmission constraints resulting in transmission congestion charges and differences in Nodal Locational Marginal Prices at the various nodes. The CAISO created a commodity, CRRs, which entitles the holder to receive (or pay) the value of transmission congestion between specific nodes, acting as an economic hedge against transmission congestion charges.

MRTU also introduces a new CAISO market called Residual Unit Commitment (RUC). This market enables CAISO to procure additional generation capacity (in addition to what cleared in the day-ahead market) to meet the CAISO-estimated load. SCE is required to participate in the RUC market with its Resource Adequacy units and may participate with other units as well.

The CAISO market that exists today for ancillary services and real-time supplemental energy will continue in MRTU, but will be adapted to the nodal pricing model and SCE will continue to participate in these markets.

Due to established regulatory mechanisms SCE's fair value changes have no impact on purchased-power expense or earnings.

Credit Risk

As part of SCE's procurement activities, SCE contracts with a number of utilities, energy companies, financial institutions, and other companies, collectively referred to as counterparties. If a counterparty were to default on its contractual obligations, SCE could be exposed to potentially volatile spot markets for buying replacement power or selling excess power. In addition, SCE would be exposed to the risk of non-payment of accounts receivable, primarily related to sales of excess energy and realized gains on derivative instruments.

To manage credit risk, SCE 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. SCE measures, monitors and mitigates credit risk to the extent possible. SCE 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. SCE's risk management committee regularly reviews and evaluates procurement credit exposure and approves credit limits for transacting with 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. However, all of the contracts that SCE has entered into with counterparties are either entered into under SCE's short-term or long-term procurement plan which has been approved by the CPUC, or the contracts are approved by the CPUC before becoming effective. As a result of regulatory recovery mechanisms, losses from non-performance are not expected to affect earnings, but may temporarily affect cash flows. SCE anticipates future delivery of energy by counterparties, but given the current market condition, SCE cannot predict whether the counterparties will be able to continue operations and deliver energy under the contractual agreements.

The credit risk exposure from counterparties for power and gas trading activities is measured as the sum of net accounts receivable (accounts receivable less accounts payable) and the current fair value of net derivative assets reflected on the balance sheet. SCE enters into master agreements which typically provide for a right of setoff. Accordingly, SCE's credit risk exposure from counterparties is based on a net exposure under these arrangements. At December 31, 2008, the amount of balance sheet exposure as described above, broken down by the credit ratings of SCE's counterparties, was as follows:

	December 31, 2008		
In millions	Exposure(2)	Collateral	Net Exposure
S&P Credit Rating(1)			
A or higher	$ 73	$ 3	$ 70
A-	81	(1)	82
BBB+	5	—	5
BBB	—	—	—
BBB-	—	—	—
Below investment grade and not rated	—	2	(2)
Total	**$ 159**	**$ 4**	**$ 155**

(1) SCE assigns a credit rating based on the lower of a counterparty's S&P or Moody's rating. For ease of reference, the above table uses the S&P classifications to summarize risk, but reflects the lower of the two credit ratings.

(2) Exposure excludes amounts related to contracts classified as normal purchase and sales and non-derivative contractual commitments that are not recorded on the consolidated balance sheet, except for any related net accounts receivable.

The credit risk exposure set forth in the above table is comprised of $10 million of net accounts receivable and payables and $145 million representing the fair value, adjusted for counterparty credit reserves, of derivative contracts.

Due to recent developments in the financial markets, the credit ratings may not be reflective of the related credit risk. The CAISO comprises 35% of the total net exposure above and is mainly related to purchases of CRRs and FTRs (see "— Commodity Price Risk" for further information). Certain of SCE's long-term tolling agreements comprise 36% of the total net exposure.

EDISON MISSION GROUP

EMG: LIQUIDITY

Liquidity

At December 31, 2008, EMG and its subsidiaries had cash and cash equivalents and short-term investments of $1.97 billion. EMG's subsidiaries had a total of $81 million of available borrowing capacity under their credit facilities. EME had a total of $59 million of available borrowing capacity under its $600 million corporate credit facility, and Midwest Generation had a total of $22 million of available borrowing capacity under its $500 million working capital facility. EMG's consolidated debt at December 31, 2008 was $4.8 billion. In addition, EME's subsidiaries had $3.6 billion of long-term lease obligations related to their sale-leaseback transactions that are due over periods ranging up to 26 years.

The following table summarizes the status of the EME and Midwest Generation credit facilities at December 31, 2008:

In millions	EME	Midwest Generation
Commitment	$ 600	$ 500
Less: Commitment from Lehman Brothers subsidiary	(36)	—
	564	500
Outstanding borrowings	(376)	(475)
Outstanding letters of credit	(129)	(3)
Amount available	**$ 59**	**$ 22**

On September 15, 2008, Lehman Brothers Holdings filed for protection under Chapter 11 of the U.S. Bankruptcy Code. A subsidiary of Lehman Brothers Holdings, Lehman Commercial Paper Inc., a lender in EME's credit agreement representing a commitment of $36 million, in September 2008 declined requests for funding under that agreement and in October 2008, filed for bankruptcy protection. Another subsidiary of Lehman Brothers Holdings, Lehman Brothers Commercial Bank, Inc., is one of the lenders in the Midwest Generation working capital facility. This subsidiary fully funded $42 million of Midwest Generation's borrowing requests, which remains outstanding. At December 31, 2008, Lehman Brothers Commercial Bank's share of the amount available to draw under the Midwest Generation working capital facility was $2 million.

Disruptions in the capital markets affected in 2008, and may continue to affect, EME's ability to finance already-developed wind projects and future commitments and projects, including significant outstanding capital commitments for wind turbines. Access to the capital markets has become subject to increased uncertainty due to the financial market and economic conditions discussed in "Edison International: Management Overview." Accordingly, EME's liquidity is currently comprised of cash on hand and cash flow generated from operations. Pending recovery of the capital markets, EME intends to preserve capital by focusing on a selective growth strategy (primarily completion of projects under construction, including the Big Sky wind project in Illinois, and development of projects deploying current turbine commitments), and using its cash and future cash flow to meet its existing contractual commitments. Moreover, disruption in the financial markets appears to have reduced trading activity in power markets which may affect the level and duration of future hedging activity and potentially increase the volatility of earnings. Long-term disruption in the capital markets could adversely affect EME's business plans and financial position.

Business Development

EME has undertaken a number of activities in 2008 with respect to wind projects, including the following:

- Completed the acquisition of a 240 MW planned wind project in Illinois, referred to as the Big Sky wind project with payments tied to various milestones. For further discussion refer to "— Capital Expenditures — Expenditures for New Projects — Big Sky Wind Project."

- Acquired and/or completed development and commenced construction with completion scheduled for 2009 of the 80 MW Elkhorn Ridge project located in Nebraska and the 100 MW High Lonesome wind project located in New Mexico. The estimated capital cost of these projects, excluding capitalized interest, is expected to be approximately $306 million. EME owns 66.67% of the Elkhorn Ridge wind project and 100% of the High Lonesome wind project. Each project will, after its completion, sell electricity pursuant to power sales agreements.

- Completed development and/or construction and commenced operations of the 38 MW Lookout wind project and the 29 MW Forward wind project, both located in Pennsylvania, the 50 MW Jeffers wind project and the 20 MW Odin wind project, both located in Minnesota, Phase I (80 MW) of the Goat Wind project in Texas, the 19 MW Spanish Fork wind project located in Utah, the 19 MW Buffalo Bear wind project located in Oklahoma, the 61 MW Mountain Wind I and the 80 MW Mountain Wind II projects, both located in Wyoming.

In addition, EME submitted bids in competitive solicitations to supply power from solar projects under development in the southwestern United States. Initial site and equipment selection have been completed along with preliminary economic feasibility studies. Further project development activities are underway to obtain transmission interconnection, site control, and construction costs estimates, and to negotiate power sales agreements. To support development activities, EME entered into an agreement with First Solar Electric, LLC to provide design, engineering, procurement, and construction services for solar projects for identified customers, subject to the satisfaction of certain contingencies and entering into definitive agreements for such services for each project.

Capital Expenditures

At December 31, 2008, the estimated capital expenditures through 2011 by EME's subsidiaries for existing projects, corporate activities and turbine commitments were as follows:

In millions	2009	2010	2011
Illinois Plants			
Plant capital expenditures	$ 65	$ 106	$ 76
Environmental expenditures	48	(a)	(a)
Homer City Facilities			
Plant capital expenditures	29	55	29
Environmental expenditures	8	14	32
New Projects			
Projects under construction	73	—	—
Turbine commitments	706	232	—
Other capital expenditures	35	9	7
Total	**$ 964**	**$ 416**	**$ 144**

(a) See discussion below regarding capital expenditures for environmental improvements at the Illinois Plants.

Expenditures for Existing Projects

Plant capital expenditures relate to non-environmental projects such as upgrades to boiler and turbine controls, replacement of major boiler components, mill steam inerting projects, generator stator rewinds, 4Kv switchgear and main power transformer replacement.

As discussed above, Midwest Generation is subject to various commitments with respect to environmental compliance. Midwest Generation is in the process of completing engineering work for the potential installation of SCR and FGD equipment on Units 5 and 6 at the Powerton Station and SNCR equipment on Unit 6 at the Joliet Station. If a decision was made to proceed with these improvements the estimated capital costs (in 2008 dollars) would be approximately:

- $1 billion for FGD equipment at the Powerton Station,
- $500 million for SCR equipment at the Powerton Station, and
- $13 million for SNCR equipment on Unit 6 at the Joliet Station.

Midwest Generation has determined that these capital expenditures could be reduced if the construction work sequence of FGD and SCR at the Powerton Station were reversed. The complexity of the Powerton Station installation and construction interferences are representative of the balance of the fleet and Midwest Generation currently estimates approximately $650/kW for any FGD installation it elects to make on other units.

A decision to make these improvements has not been made. Midwest Generation is still reviewing all technology and unit shutdown combinations, including interim and alternative compliance solutions. For further discussion of environmental regulations and current status of environmental improvements in Illinois, see "Other Developments — Environmental Matters."

Expenditures for New Projects

At December 31, 2008, EME had committed to purchase turbines (as reflected in the above table of capital expenditures) for wind projects that aggregate 942 MW. The turbine commitments generally represent approximately two-thirds of the total capital costs of EME's wind projects. As of December 31, 2008, EME had a development pipeline of potential wind projects with projected installed capacity of approximately 5,000 MW. The development pipeline represents potential projects with respect to which EME either owns the project rights or has exclusive acquisition rights. Completion of development of a wind project may take a number of years due to factors that include local permit requirements, willingness of local utilities to purchase renewable power at sufficient prices to earn an appropriate rate of return, and availability and prices of equipment. Furthermore, successful completion of a wind project is dependent upon obtaining permits and agreements necessary to support an investment. There is no assurance that each project included in the development pipeline currently or added in the future will be successfully completed, or that EME will be able to successfully develop projects utilizing all of its turbine commitments. EME may also postpone or cancel wind turbine commitments, subject to the provisions of the relevant contracts.

Big Sky Wind Project

The Big Sky wind project is a 240 MW planned wind project in Illinois. EME has commenced pre-construction activities for equipment purchases, site development and interconnection activities ($99 million capitalized at December 31, 2008). Release of the project for full construction is pending a decision on selection of turbines. The costs to complete the Big Sky wind project, including construction and turbine transportation and installation, are approximately $165 million. This estimate excludes the turbine costs set forth as turbine commitments in the table above and costs incurred to date. Upon completion, the project plans to sell electricity into the PJM market as a merchant generator or to local utilities under power sales contracts.

Walnut Creek Project

Walnut Creek Energy, a subsidiary of EME, was awarded by SCE, through a competitive bidding process, a ten-year power sales contract starting in 2013 for the output of the Walnut Creek project. In December 2008, EME and Walnut Creek Energy cancelled the turbine order for the Walnut Creek project pending resolution of the legal challenges discussed below and recorded a pre-tax charge of $23 million ($14 million, after tax). EME plans to purchase turbines for the project subject to resolution of uncertainty regarding the availability of required emission credits.

In the air basins regulated by SCAQMD, the need for particulate matter (PM10) and SO_2emission credits exceeds available supply, and it is difficult to create new credits. Walnut Creek will be unable to begin construction until the legal challenges to the Priority Reserve emission credits have been favorably resolved or another source of credits for the project has been identified. The capital costs to construct this project, excluding interest, are estimated in the range of $500 million to $600 million. See "Other Developments — Environmental Matters — Priority Reserve Legal Challenges" for more information.

Credit Ratings

Overview

Credit ratings for EMG's direct and indirect subsidiaries at December 31, 2008, were as follows:

	Moody's Rating	S&P Rating	Fitch Rating
EME	B1	BB-	BB-
Midwest Generation[(1)]	Baa3	BB+	BBB-
EMMT	Not Rated	BB-	Not Rated
Edison Capital (Edison Funding)	Ba1	BB+	Not Rated

(1) First priority senior secured rating.

On December 23, 2008, S&P assigned a negative outlook to its corporate ratings for EME, Midwest Generation, and EMMT. S&P assigned a negative outlook to Edison Funding's credit rating and in August 2008, Moody's placed Edison Funding's senior notes under review for a possible rating downgrade. EMG 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. EMG 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.

EMG 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, including EMMT.

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. During 2008, EME sold 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. In order to continue to sell forward the output of the Homer City facilities through EMMT, either: (1) a consent from the sale-leaseback owner participant must be obtained; 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 participants that allows EME Homer City to enter into such sales, under specified conditions, through March 1, 2014. EME is permitted to sell the output of the Homer City facilities into the spot market at any time. See "EMG: 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, EMMT may be required to support its risk of nonperformance through parent guarantees, margining or other credit support. EME has entered into guarantees in support of EMMT's hedging and trading activities; however, because the credit ratings of EMMT and EME are below investment grade, EME has historically also provided collateral in the form of cash and letters of credit for the benefit of counterparties related to the net of accounts payable, accounts receivable, unrealized losses, and unrealized gains in connection with these hedging and trading activities. At December 31, 2008, EMMT had deposited $43 million in cash with clearing brokers in support of futures contracts and had deposited $45 million in cash with counterparties in support of forward energy and congestion contracts. In addition, EME had received cash collateral of $225 million at December 31, 2008, to support credit risk of counterparties under margin agreements.

Future cash collateral requirements may be higher than the margin and collateral requirements at December 31, 2008, if wholesale energy prices or the amount hedged changes. EME estimates that margin and collateral requirements for energy and congestion contracts outstanding as of December 31, 2008 could increase by approximately $140 million over the remaining life of the contracts using a 95% confidence level. Certain EMMT hedge contracts do not require margining, but contain provisions that require EME or Midwest Generation to comply with the terms and conditions of their credit facilities. The credit facilities contain financial covenants which are described further in "— Dividend Restrictions in Major Financings." Furthermore, the hedge contracts include provisions relating to a change in control or material adverse effect resulting from amendments or modifications to the related credit facility. Failure by EME or Midwest Generation to comply with these provisions would result in a termination event under the hedge contracts, enabling the counterparties to terminate and liquidate all outstanding transactions and demand immediate payment of amounts owed to them. EMMT also has hedge contracts that do not require margining, but contain the right of each party to request additional credit support in the form of adequate assurance of performance in the case of an adverse development affecting the other party. The aggregate fair value of hedge contracts with credit-risk related contingent features was a net asset at December 31, 2008 and, accordingly, the contingent features described above do not currently have a liquidity exposure. Future increases in power prices could expose EME or Midwest Generation to termination payments or posting additional collateral under the contingent features described above.

Midwest Generation has cash on hand to support margin requirements specifically related to contracts entered into by EMMT related to the Illinois Plants. At December 31, 2008, Midwest Generation had available $22 million of borrowing capacity under its $500 million working capital facility. In addition, EME has cash on hand and $59 million of borrowing capacity available under its $600 million working capital facility to provide credit support to subsidiaries.

Intercompany Tax-Allocation Agreement

EME and Edison Capital are included in the consolidated federal and combined state income tax returns of Edison International and are eligible to participate in tax-allocation payments with other subsidiaries of Edison International in circumstances where domestic tax losses are incurred. The rights of EME and Edison Capital to receive and the amount of and timing of tax-allocation payments are dependent on the inclusion of EME and Edison Capital 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 EMG's subsidiaries, and other subsidiaries of Edison International and specific procedures regarding allocation of state taxes. EME and Edison Capital receive 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 or Edison Capital'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, each of EME and Edison Capital 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 $95 million, $112 million and $151 million in 2008, 2007 and 2006, respectively. Edison Capital made net tax-allocation payments to Edison International of $15 million in 2008 and received net tax-allocation payments from Edison International of $17 million and $135 million in 2007 and 2006, respectively. MEHC (parent) made net tax-allocation payments to Edison International of $3 million in 2008 and received net tax-allocation payments from Edison International of $48 million and $43 million in 2007 and 2006, respectively.

Dividend Restrictions in Major Financings

General

Each of EMG's direct or indirect subsidiaries is organized as a legal entity separate and apart from EMG and its other subsidiaries. Assets of EMG's subsidiaries are not available to satisfy 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 EMG or to its subsidiary holding companies.

Key Ratios of EMG's Principal Subsidiaries Affecting Dividends

Set forth below are key ratios of EME's principal subsidiaries required by financing arrangements at December 31, 2008 or for the 12 months ended December 31, 2008:

Subsidiary	Financial Ratio	Covenant	Actual
Midwest Generation (Illinois Plants)	Debt to Capitalization Ratio	Less than or equal to 0.60 to 1	0.28 to 1
EME Homer City (Homer City facilities)	Senior Rent Service Coverage Ratio	Greater than 1.7 to 1	2.05 to 1

Edison Capital's ability to make dividend payments is currently restricted by covenants in its financial instruments, which require Edison Capital, through a wholly owned subsidiary, to maintain a specified minimum net worth of $200 million. Edison Capital satisfied this minimum net worth requirement as of December 31, 2008.

Midwest Generation Financing Restrictions on Distributions

Midwest Generation is bound by the covenants in its credit agreement and 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, enter into swap agreements, or engage in transactions for any speculative purpose. In order for Midwest Generation to make a distribution, it must be in compliance with the covenants specified under its credit agreement, including maintaining a debt to capitalization ratio of no greater than 0.60 to 1.

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.

EME's Credit Facility Financial Ratios

EME's credit facility contains financial covenants which require EME to maintain a minimum interest coverage ratio and a maximum corporate debt-to-corporate capital ratio as such terms are defined in the credit facility. The key ratios at December 31, 2008 or for the 12 months ended December 31, 2008 are as follows:

Financial Ratio	Covenant	Actual
Interest Coverage Ratio	Not less than 1.2 to 1	1.98 to 1
Corporate Debt to Corporate Capital Ratio	Not more than 0.75 to 1	0.60 to 1

EME's Senior Notes and Guaranty of Powerton-Joliet Leases

EME is restricted from the sale or disposition of assets, which includes the making of a distribution, if the aggregate net book value of all such sales during the most recent 12-month period would exceed 10% of consolidated net tangible assets as defined in such agreements computed as of the end of the most recent fiscal quarter preceding such sale. At December 31, 2008, the maximum sale or disposition of EME assets is approximately $800 million. This limitation does not apply if the proceeds are invested in assets in similar or related lines of business of EME. Furthermore, EME may sell or otherwise dispose of assets in excess of such 10% limitation if the proceeds from such sales or dispositions, which are not reinvested as provided above, are retained by EME as cash or cash equivalents or are used by EME to repay senior debt of EME or debt of its subsidiaries.

EMG: OTHER DEVELOPMENTS

RPM Buyers' Complaint

On May 30, 2008, a group of entities referring to themselves as the "RPM Buyers" filed a complaint at the FERC asking that PJM's RPM, as implemented through the transitional base residual auctions establishing capacity payments for the period from June 1, 2008 through May 31, 2011, be found to have produced unjust and unreasonable capacity prices. On September 19, 2008, the FERC dismissed the RPM Buyers' complaint, finding that the RPM Buyers had failed to allege or prove that any party violated PJM's tariff and market rules, and that the prices determined during the transition period were determined in accordance with PJM's FERC-approved tariff. On October 20, 2008, the RPM Buyers requested rehearing of the FERC's order dismissing their complaint. This matter is currently pending before the FERC. EME cannot predict the outcome of this matter.

Midwest Generation New Source Review Notice of Violation

On August 3, 2007, Midwest Generation received an NOV from the US EPA alleging that, beginning in the early 1990s and into 2003, Midwest Generation or Commonwealth Edison performed repair or replacement projects at six Illinois coal-fired electric generating stations in violation of the Prevention of Significant Deterioration requirements and of the New Source Performance Standards of the CAA, including alleged requirements to obtain a construction permit and to install best available control technology at the time of the projects. The US EPA also alleges that Midwest Generation and Commonwealth Edison violated certain operating permit requirements under Title V of the CAA. Finally, the US EPA alleges violations of certain opacity and particulate matter standards at the Illinois Plants. The NOV does not specify the penalties or other relief that the US EPA seeks for the alleged violations. Midwest Generation, Commonwealth Edison, the US EPA, and the DOJ are in talks designed to explore the possibility of a settlement. If the settlement talks fail and the DOJ files suit, litigation could take many years to resolve the issues alleged in the NOV. Midwest Generation cannot predict the outcome of this matter or estimate the impact on its facilities, its results of operations, financial position or cash flows.

On August 13, 2007, Midwest Generation and Commonwealth Edison received a letter signed by several Chicago-based environmental action groups stating that, in light of the NOV, the groups are examining the possibility of filing a citizen suit against Midwest Generation and Commonwealth Edison based presumably on the same or similar theories advanced by the US EPA in the NOV.

By letter dated August 8, 2007, Commonwealth Edison advised EME that Commonwealth Edison believes it is entitled to indemnification for all liabilities, costs, and expenses that it may be required to bear as a result of the NOV. By letter dated August 16, 2007, Commonwealth Edison tendered a request for indemnification to EME for all liabilities, costs, and expenses that Commonwealth Edison may be required to bear if the environmental groups were to file suit. Midwest Generation and Commonwealth Edison are cooperating with one another in responding to the NOV.

EME Homer City New Source Review Notice of Violation

On June 12, 2008, EME Homer City received an NOV from the US EPA alleging that, beginning in 1988, EME Homer City (or former owners of the Homer City facilities) performed repair or replacement projects at Homer City Units 1 and 2 without first obtaining construction permits as required by the Prevention of Significant Deterioration requirements of the CAA. The US EPA also alleges that EME Homer City has failed to file timely and complete Title V permits. The NOV does not specify the penalties or other relief that the US EPA seeks for alleged violations. EME Homer City has met with the US EPA and has expressed its intent to explore the possibility of a settlement. If no settlement is reached and the DOJ files suit, litigation could take many years to resolve the issues alleged in the NOV. EME Homer City cannot predict at this time what effect this matter may have on its facilities, its results of operations, financial position or cash flows.

EME Homer City has sought indemnification for liability and defense costs associated with the NOV from the sellers under the asset purchase agreement pursuant to which EME Homer City acquired the Homer City facilities. The sellers responded by denying the indemnity obligation, but accepting the defense of the claims.

EME Homer City notified the sale-leaseback owner participants of the Homer City facilities of the NOV under the operative indemnity provisions of the sale-leaseback documents. The owner participants of the Homer City facilities, in turn, have sought indemnification and defense from EME Homer City for costs and liability associated with the EME Homer City NOV. EME Homer City responded by undertaking the indemnity obligation and defense of the claims.

Federal and State Income Taxes

Edison International files its federal and state income tax returns on a consolidated basis and files on a combined basis in California and certain other states. EMG is included in the consolidated federal and state combined income tax returns. See "Other Developments — Federal and State Income Taxes" for further discussion of these matters.

EMG: MARKET RISK EXPOSURES

Introduction

EMG'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.

Commodity Price Risk

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 "gross margin at risk" to identify, measure, monitor and control its overall market risk exposure with respect to hedge positions at the Illinois Plants, the Homer City facilities, and the merchant wind projects, and "value at risk" to identify, measure, monitor and control its overall risk exposure in respect of its trading positions. The use of these measures 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, and gross margin at risk measures the potential change in value, of an asset or position, in each case over a given time interval, under normal market conditions, at a given confidence level. Given the inherent limitations of these measures and reliance on a single type of risk measurement tool, EME supplements these approaches with the use of stress testing and worst-case scenario analysis for key risk factors, as well as stop-loss triggers and counterparty credit exposure limits.

Hedging Strategy

To reduce its exposure to market risk, EME hedges a portion of its electricity sales through EMMT, an EME subsidiary engaged in the power marketing and trading business. To the extent that EME does not hedge its electricity sales, 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 futures contracts cleared on the Intercontinental Trading Exchange and the New York Mercantile Exchange or executed bilaterally with counterparties,
- forward sales transactions entered into on a bilateral basis with third parties, including electric utilities and power marketing companies,
- 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, and
- participation in capacity auctions.

The extent to which EME hedges its market price risk depends on several factors. First, EME evaluates over-the-counter market prices to determine whether the types of hedge transactions set forth above 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 addition, Midwest Generation may grant liens on its property in support of hedging transactions associated with the Illinois Plants. See "— Credit Risk" below.

In the case of hedging transactions related to the generation and capacity of the Homer City facilities, credit support is provided by EME.

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 or the AEP/Dayton Hub, both in PJM, or may be entered into at other trading hubs, including the Cinergy Hub in the MISO. These trading hubs have been the most liquid locations for hedging purposes. 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 2008, 2007 and 2006:

	24-Hour Northern Illinois Hub Historical Energy Prices[1]		
	2008	**2007**	**2006**
January	**$ 47.09**	$ 35.75	$ 42.27
February	**54.46**	56.64	42.66
March	**58.58**	42.04	42.50
April	**53.87**	48.91	43.16
May	**44.49**	44.49	39.96
June	**56.06**	39.76	34.80
July	**63.79**	43.40	51.82
August	**52.66**	57.97	54.76
September	**43.08**	39.68	31.87
October	**35.31**	50.14	37.80
November	**38.34**	43.25	41.90
December	**40.43**	44.36	33.57
Yearly Average	**$ 49.01**	$ 45.53	$ 41.42

(1) Energy prices were calculated at the Northern Illinois Hub delivery point using hourly real-time prices as published by PJM.

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 2009 and calendar year 2010 "strips," which are defined as energy purchases for the entire calendar year, as quoted for sales into the Northern Illinois Hub during 2008:

	24-Hour Northern Illinois Hub Forward Energy Prices[1]	
	2009	2010
January 31, 2008	$ 52.30	$ 53.14
February 29, 2008	57.29	56.45
March 31, 2008	55.48	55.50
April 30, 2008	56.80	49.14
May 31, 2008	57.03	52.10
June 30, 2008	62.17	56.08
July 31, 2008	52.48	50.94
August 31, 2008	50.49	49.30
September 30, 2008	48.03	48.52
October 31, 2008	42.03	43.10
November 30, 2008	41.43	42.45
December 31, 2008	38.59	39.55

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

EMMT engages in hedging activities for the Illinois Plants to hedge the risk of future change in the price of electricity. Hedging activities for energy only contracts are typically weighted toward on-peak periods. The following table summarizes Midwest Generation's hedge position at December 31, 2008:

	2009		2010		2011	
	GWh	Average price/ MWh	GWh	Average price/ MWh	GWh	Average price/ MWh
Energy Only Contracts[(1)]						
Northern Illinois Hub — AEP/Dayton Hub	9,945	$ 65.44	6,555	$ 68.61	612	$ 76.40
Load Requirements Services Contracts[(2)(3)]						
Northern Illinois Hub	1,571	$ 63.65	—	—	—	—
Total estimated GWh	11,516		6,555		612	

(1) 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 positions at December 31, 2008 are not directly comparable to the 24-hour Northern Illinois Hub prices set forth above.

(2) 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 GWh 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.

(3) The average price per MWh 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 MWh under a load requirements services contract is not comparable to the sale of power under an energy only contract. The average price per MWh under a load requirements services contract represents the sale of the bundled product based on an estimated customer load profile.

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		
	2008	2007	2006	**2008**	2007	2006
January	**$ 54.32**	$ 40.30	$ 48.67	**$ 66.80**	$ 44.63	$ 54.57
February	**61.74**	64.27	49.54	**68.29**	73.93	56.39
March	**65.37**	55.00	53.26	**70.48**	61.02	58.30
April	**61.99**	52.42	48.50	**69.12**	58.74	49.92
May	**49.37**	48.12	44.71	**59.84**	53.89	48.55
June	**78.72**	45.88	38.78	**98.50**	60.19	45.78
July	**72.39**	48.23	53.68	**91.80**	58.89	63.47
August	**60.16**	55.44	58.60	**73.91**	71.00	76.57
September	**52.33**	48.90	33.26	**66.04**	60.14	34.40
October	**44.46**	53.89	37.42	**52.88**	61.11	39.65
November	**44.99**	47.27	40.13	**54.50**	55.25	44.83
December	**46.74**	52.58	35.29	**50.62**	59.67	40.53
Yearly Average	**$ 57.72**	$ 51.03	$ 45.15	**$ 68.56**	$ 59.87	$ 51.08

(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 year 2009 and calendar year 2010 "strips," which are defined as energy purchases for the entire calendar year, as quoted for sales into the PJM West Hub during 2008:

	24-Hour PJM West Hub Forward Energy Prices[1]	
	2009	2010
January 31, 2008	$ 69.06	$ 68.43
February 29, 2008	75.03	72.59
March 31, 2008	75.55	71.76
April 30, 2008	79.64	74.91
May 31, 2008	83.91	78.42
June 30, 2008	94.90	87.10
July 31, 2008	75.89	73.66
August 31, 2008	70.49	70.44
September 30, 2008	66.23	68.31
October 31, 2008	59.32	62.97
November 30, 2008	58.17	62.39
December 31, 2008	54.66	59.21

(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.

EMMT engages in hedging activities for the Homer City facilities to hedge the risk of future change in the price of electricity. Hedging activities are typically weighted toward on-peak periods. The following table summarizes EME Homer City's hedge position at December 31, 2008:

	2009	2010
GWh	4,096	2,662
Average price/MWh[1]	$ 82.94	$ 90.53

(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 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, 2008 is not directly comparable to the 24-hour PJM West Hub prices set forth above.

The average price/MWh for EME Homer City's hedge position is based on the 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.

Capacity Price Risk

On June 1, 2007, PJM implemented the RPM for capacity. The purpose of the RPM is to provide a long-term pricing signal for capacity resources. The RPM provides a mechanism for PJM to satisfy the region's need for generation capacity, the cost of which is allocated to load-serving entities through a locational reliability charge.

The following table summarizes the status of capacity sales for Midwest Generation and EME Homer City at December 31, 2008:

	Fixed Price Capacity Sales					
	Through RPM Auction, Net		Non-unit Specific Capacity Sales		Variable Capacity Sales	
	MW	Price per MW-day	MW	Price per MW-day	MW	Price per MW-day
January 1, 2009 to May 31, 2009						
Midwest Generation	2,957	$ 122.41[1]	880	$ 64.35	—	—
EME Homer City	820	111.92	—	—	905	$ 56.56[2]
June 1, 2009 to May 31, 2010						
Midwest Generation	4,582	102.04	723	72.84	—	—
EME Homer City	1,670	191.32	—	—	—	—
June 1, 2010 to May 31, 2011						
Midwest Generation	4,929	174.29	—	—	—	—
EME Homer City	1,813	174.29	—	—	—	—
June 1, 2011 to May 31, 2012						
Midwest Generation	4,582	110.00	—	—	—	—
EME Homer City	1,771	110.00	—	—	—	—

(1) The original price of $111.92 was affected by Midwest Generation's participation in a supplemental RPM auction during the first quarter of 2008 which resulted in purchasing certain capacity amounts at a price of $10 per MW-day, thereby reducing the aggregate forward capacity sales for this period and increasing the effective capacity price to $122.41.

(2) Actual contract price is a function of NYISO capacity auction clearing prices in January through April 2009 and forward over-the-counter NYISO capacity prices on December 31, 2008 for May 2009.

Revenues from the sale of capacity from Midwest Generation and EME Homer City beyond the periods set forth above will depend upon the amount of capacity available and future market prices either in PJM or nearby markets if EME has an opportunity to capture a higher value associated with those markets. Under PJM's RPM system, the market price for capacity is generally determined by aggregate market-based supply conditions and an administratively set aggregate demand curve. Among the factors influencing the supply of capacity in any particular market are plant forced outage rates, plant closings, plant delistings (due to plants being removed as capacity resources and/or to export capacity to other markets), capacity imports from other markets, and the CONE.

Midwest Generation entered into hedge transactions in advance of the RPM auctions with counterparties that are settled through PJM. In addition, the load service requirements contracts entered into by Midwest Generation with Commonwealth Edison include energy, capacity and ancillary services (sometimes referred to as a "bundled product"). Under PJM's business rules, Midwest Generation sells all of its available capacity (defined as unit capacity less forced outages) into the RPM and is subject to a locational reliability charge for the load under these contracts. This means that the locational reliability charge generally offsets the related amounts sold in the RPM, which Midwest Generation presents on a net basis in the table above.

Prior to the RPM auctions for the relevant delivery periods, EME Homer City sold a portion of its capacity to an unrelated third party for the delivery period of June 1, 2008 through May 31, 2009. EME Homer City is not receiving the RPM auction clearing price for this previously sold capacity. The price EME Homer City is receiving for these capacity sales is a function of NYISO capacity clearing prices resulting from separate NYISO capacity auctions.

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 settlement points at the Northern Illinois Hub and the AEP/Dayton 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 or AEP/Dayton 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. Effective June 1, 2007, PJM implemented marginal losses which adjust the algorithm that calculates locational marginal prices to include a component for marginal transmission losses in addition to the component included for congestion. 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 2008, 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 16%, compared to 15% during 2007 and 12% during 2006. The monthly average difference during 2008 ranged from 7% to 21%. During 2008, transmission congestion in PJM has resulted in prices at the individual busbars of the Illinois Plants being lower than those at the Northern Illinois Hub by an average of 2%.

By entering into cash settled futures contracts and forward contracts using the PJM West Hub, the Northern Illinois Hub, and the AEP/Dayton 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 may purchase financial transmission rights and basis swaps in PJM for EME Homer City. 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 and Transportation 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 2012. The following table summarizes the amount of coal under contract at December 31, 2008 for the next four years:

	Amount of Coal Under Contract in Millions of Equivalent Tons[1]			
	2009	2010	2011	2012
Illinois Plants	17.7	11.7	—	—
Homer City facilities[2]	5.1	0.6	0.3	0.1

(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.

(2) At December 31, 2008, there are options to purchase additional coal of 0.7 million tons in 2010, 0.6 million tons in 2011, 0.5 million tons in 2012, and 0.1 million tons in 2013. Options to purchase 1.2 million tons in 2010 and 2011 are the subject of a dispute with the supplier. Pending dispute resolution, EME is exposed to price risk related to these volumes at December 31, 2008.

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, increased substantially during 2008 and increased steadily during 2007 from 2006. The price of NAPP coal (with 13,000 Btu per pound heat content and <3.0 pounds of SO_2 per MMBtu sulfur content) ranged from $61.75 per ton to $150 per ton during 2008 and decreased to a price of $76 per ton at January 9, 2009, as reported by the EIA. The 2008 increase in NAPP coal prices was primarily attributable to increased international and Atlantic basin coal demand resulting from a variety of factors in several countries consuming this coal. The current global economic conditions have tempered this demand and prices moderated as 2008 came to a close. In 2007, the price of NAPP coal fluctuated between $44.00 per ton to $55.25 per ton, which was the price per ton at December 21, 2007, as reported by the EIA. In 2006, the price of NAPP coal fluctuated between $37.50 per ton and $45.00 per ton, with a price of $43.00 per ton at December 15, 2006, as reported by the EIA. The 2007 increase in the NAPP coal price was in line with normal market price volatility.

Prices of PRB coal (with 8,800 Btu per pound heat content and 0.8 pounds of SO_2 per MMBtu sulfur content) purchased for the Illinois Plants increased during 2008 from 2007 year-end prices and increased during 2007 from 2006 year-end prices. The 2008 and 2007 fluctuations in PRB coal prices were in line with normal market price volatility. The price of PRB coal fluctuated between $11 per ton to $14.50 per ton during 2008, with a price of $13 per ton at January 9, 2009, as reported by the EIA. In 2007, the price of PRB coal ranged from $8.35 per ton to $11.50 per ton, which was the price per ton at December 21, 2007. In 2006, the price of PRB coal ranged from $20.66 per ton in January 2006 to $9.90 per ton at December 15, 2006, as reported by the EIA.

EME has contractual agreements for the transport of coal to its facilities. The primary contract is with Union Pacific Railroad (and various delivering carriers), which extends through 2011. EME is exposed to price risk related to higher transportation rates after the expiration of its existing transportation contracts. Current transportation rates for PRB coal are higher than the existing rates under contract (transportation costs are more than 50% of the delivered cost of PRB coal to the Illinois Plants).

Based on EME's anticipated coal requirements in 2009 in excess of the amount under contract, EME expects that a 10% change in the price of coal at December 31, 2008 would increase or decrease pre-tax income in 2009 by approximately $1 million.

Emission Allowances Price Risk

The federal Acid Rain Program requires electric generating stations to hold SO_2 allowances sufficient to cover their annual emissions. Illinois and Pennsylvania regulations implemented the federal NO_X SIP Call which required, through 2008, the holding of NO_X allowances to cover ozone season NO_X emissions. In addition, pursuant to Pennsylvania's and Illinois' implementation of the CAIR, electric generation stations are required to hold seasonal and annual NO_X allowances beginning January 1, 2009. 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. 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. See "Other Developments — Environmental Matters — Air Quality Regulation — Clean Air Interstate Rule" for further discussion of the CAIR.

EME is subject to price risk for purchases of emission allowances required for actual emissions greater than allowances held. The market price for emission allowances may vary significantly. For example, the average purchase price of SO_2 allowances was $315 per ton in 2008, $512 per ton in 2007 and $664 per ton in 2006. Based on broker's quotes and information from public sources, the spot price for SO_2 allowances was $210 per ton at December 31, 2008. EME does not anticipate any requirements to purchase SO_2 emission allowances for 2009.

Based on EME's anticipated annual and seasonal NO_X requirements for 2009 beyond those allowances already purchased, EME expects that a 10% change in the price of annual and seasonal NO_X emission allowances at December 31, 2008 would increase or decrease pre-tax income in 2009 by approximately $4 million.

See "Other Developments — Environmental Matters — Air Quality Regulation" 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 Policies and Estimates — Critical Accounting Policies and 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:
  - o 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
  - o 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, 2008:

In millions **Years Ended December 31,**	**2008**	**2007**	**2006**
Illinois Plants			
Non-qualifying hedges	**$ (16)**	$ (14)	$ 28
Ineffective portion of cash flow hedges	**10**	(11)	2
Homer City facilities			
Non-qualifying hedges	**1**	(1)	2
Ineffective portion of cash flow hedges	**20**	(9)	33
Total unrealized gains (losses)	**$ 15**	$ (35)	$ 65

On September 15, 2008, Lehman Brothers Holdings filed for protection under Chapter 11 of the U.S. Bankruptcy Code. EME had power contracts with Lehman Brothers Commodity Services, Inc., a subsidiary of Lehman Brothers Holdings, for Midwest Generation for 2009 and 2010. Lehman Brothers Commodity Services also filed for bankruptcy protection on October 3, 2008. The obligations of Lehman Brothers Commodity Services under the power contracts are guaranteed by Lehman Brothers Holdings. These contracts qualified as cash flow hedges under SFAS No. 133 until EME dedesignated the power contracts effective September 12, 2008 when it determined that it was no longer probable that performance would occur. The amount recorded in accumulated comprehensive income (loss) related to the effective portion of the hedges was $24 million pre-tax on that date. Since the power contracts are no longer being accounted for as cash flow hedges under SFAS No. 133 and subsequently were terminated, the subsequent change in fair value was recorded as an unrealized loss in 2008. Under SFAS No. 133, the pre-tax amount recorded in accumulated other comprehensive income (loss) will be reclassified to operating revenues based on the original forecasted transactions in 2009 ($15 million) and 2010 ($9 million), unless it becomes probable that the forecasted transactions will no longer occur.

At December 31, 2008, excluding the unrealized losses described above related to Lehman Brothers Commodity Services, unrealized gains of $1 million were recognized from non-qualifying hedge contracts or the ineffective portion of cash flow hedges related to subsequent periods ($2 million in unrealized losses for 2009 and $3 million in unrealized gains for 2010).

Fair Value of Financial Instruments

EME adopted SFAS No. 157 effective January 1, 2008. The standard established a hierarchy for fair value measurements. See "Edison International Notes to Consolidated Financial Statements — Note 10. Fair Value Measurements," for further discussion of the adoption of SFAS No. 157.

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,	2008	2007
Commodity price:		
Electricity contracts	$ 375	$ (137)

In assessing the fair value of EME's non-trading derivative financial instruments, EME uses quoted market prices and forward market prices adjusted for credit risk. 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 fair value of electricity contracts at December 31, 2008 as compared to December 31, 2007 is attributable to a decline in the average market prices for power as compared to contracted prices at December 31, 2008, which is the valuation date. A 10% change in the market price at December 31, 2008 would increase or decrease the fair value of outstanding derivative commodity price contracts by approximately $59 million. The following table summarizes the maturities and the related fair value of EME's commodity derivative assets and liabilities as of December 31, 2008:

In millions	Total Fair Value	Maturity <1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity >5 years
Prices provided by external sources	$ 373	$ 232	$ 141	$ —	$ —
Prices based on models and other valuation methods	2	(1)	3	—	—
Total	**$ 375**	**$ 231**	**$ 144**	**$ —**	**$ —**

Prices provided by external sources in the preceding table include derivatives whose fair value is based on forward market prices in active markets adjusted for non-performance risks which would be considered Level 2 derivative positions when there are no unobservable inputs that are significant to the valuation. EME obtains forward market prices from traded exchanges (ICE Futures U.S. or New York Mercantile Exchange) and available broker quotes. Then, EME selects a primary source that best represents traded activity for each market to develop observable forward market prices in determining the fair value of these positions. Broker quotes or prices from exchanges are used to validate and corroborate the primary source. These price quotations reflect mid-market prices (average of bid and ask) and are obtained from sources that EME believes to provide the most liquid market for the commodity. EME considers broker quotes to be observable when corroborated with other information which may include a combination of prices from exchanges, other brokers and comparison to executed trades.

Energy Trading Derivative Financial Instruments

The fair value of the commodity financial instruments related to energy trading activities as of December 31, 2008 and 2007 are set forth below:

	December 31, 2008		December 31, 2007	
In millions	Assets	Liabilities	Assets	Liabilities
Electricity contracts	**$ 282**	**$ 172**	$ 141	$ 9
Other	**3**	**1**	—	—
Total	**$ 285**	**$ 173**	$ 141	$ 9

The change in the fair value of trading contracts for the year ended December 31, 2008 was as follows:

In millions	
Fair value of trading contracts at January 1, 2008	$ 132
Net gains from energy trading activities	171
Amount realized from energy trading activities	(182)
Other changes in fair value	(9)
Fair value of trading contracts at December 31, 2008	**$ 112**

A 10% change in the market price at December 31, 2008 would increase or decrease the fair value of trading contracts by approximately $2 million. The impact of changes to the various inputs used to determine the fair value of Level 3 derivatives is not currently material to EME's results of operations as such changes are offset by similar changes in derivatives classified within Level 3 as well as other categories.

The following table summarizes the maturities, the valuation method and the related fair value of energy trading assets and liabilities (as of December 31, 2008):

In millions	Total Fair Value	Maturity <1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity >5 years
Prices actively quoted	$ 2	$ 3	$ (1)	$ —	$ —
Prices provided by external sources	(102)	(77)	(23)	(2)	—
Prices based on models and other valuation methods	212	109	64	31	8
Total	**$ 112**	**$ 35**	**$ 40**	**$ 29**	**$ 8**

In the table above, prices actively quoted include exchange traded derivatives. Prices provided by external sources include non-exchange traded derivatives which are priced based on forward market prices adjusted for non-performance risks which would be considered Level 2 derivative positions when there are no unobservable inputs that are significant to the valuation. Fair values for Level 2 derivative positions are determined using the same methodology previously described for non-trading derivative financial instruments. Fair value for Level 3 derivative positions is determined using prices based on models and other valuation methods and include load requirements services contracts, illiquid financial transmission rights, over-the-counter derivatives at illiquid locations and long-term power agreements. For long-term power agreements, EME's subsidiary records these agreements at fair value based upon a discounting of future electricity prices derived from a proprietary model using the risk free discount rate for a similar duration contract, adjusted for credit and liquidity.

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 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 EME would expect to incur if a counterparty failed to perform pursuant to the terms of its 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.

EME has established processes to determine and monitor the creditworthiness of counterparties. EME manages the credit risk of its counterparties 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 hedging and trading activities is measured as the sum of net receivables (accounts receivable less accounts payable) and the current fair value of net derivative assets. EME's subsidiaries enter into master agreements and other arrangements in conducting such activities which typically provide for a right of setoff in the event of bankruptcy or default by the counterparty. At December 31, 2008, the balance sheet exposure as described above, broken down by the credit ratings of EME's counterparties, was as follows:

In millions	December 31, 2008		
Credit Rating(1)	**Exposure**(2)	**Collateral**	**Net Exposure**
A or higher	$ 379	$ (222)	$ 157
A-	62	—	62
BBB+	49	—	49
BBB	132	1	133
BBB-	51	—	51
Below investment grade	10	(8)	2
Total	**$ 683**	**$ (229)**	**$ 454**

(1) EME assigns a credit rating based on the lower of a counterparty's S&P or Moody's rating. For ease of reference, the above table uses the S&P classifications to summarize risk, but reflects the lower of the two credit ratings.

(2) Exposure excludes amounts related to contracts classified as normal purchase and sales and non-derivative contractual commitments that are not recorded on the consolidated balance sheet, except for any related accounts receivable.

The credit risk exposure set forth in the above table is comprised of $203 million of net accounts receivable and payables and $481 million representing the fair value of derivative contracts. The exposure is based on master netting agreements with the related counterparties.

Included in the table above are exposures to financial institutions with credit ratings of A- or above. Due to recent developments in the financial markets, the credit ratings may not be reflective of the related credit risks. See "Edison International: Management Overview — Financial Markets and Economic Conditions" for further discussion. The total net exposure to financial institutions at December 31, 2008 was $151 million. This total net exposure excludes positions with Lehman Brothers Holdings and its subsidiaries. Five financial institutions comprise 29% of the net exposure above with the largest single net exposure with a financial institution representing 11%. In addition to the amounts set forth in the above table, EME's subsidiaries have posted an $88 million cash margin in the aggregate with PJM, NYISO, MISO, clearing brokers and other counterparties to support hedging and trading activities. Margining posted to support these activities also exposes EME to credit risk of the related entities.

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 project.

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 50% of EME's consolidated operating revenues for the year ended December 31, 2008. Moody's rates PJM's 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, 2008, EME's account receivable due from PJM was $61 million.

EME also derived a significant source of its revenues from the sale of energy, capacity and ancillary services generated at the Illinois Plants to Commonwealth Edison under load requirements services contracts. Sales under these contracts accounted for 12% of EME's consolidated operating revenues for the year ended December 31, 2008. Commonwealth Edison's senior unsecured debt ratings are BBB- by S&P and Baa3 by Moody's. At December 31, 2008, EME's account receivable due from Commonwealth Edison was $23 million.

For the year ended December 31, 2008, a third customer, Constellation Energy Commodities Group, Inc., accounted for 10% of EME's consolidated operating revenues. Sales to Constellation are primarily generated from EME's merchant plants and largely consist of energy sales under forward contracts. The contract with Constellation is guaranteed by Constellation Energy Group, Inc., which has a senior unsecured debt rating of BBB by S&P and Baa3 by Moody's. At December 31, 2008, EME's account receivable due from Constellation was $22 million.

The terms of EME's wind turbine supply agreements contain significant obligations of the suppliers in the form of manufacturing and delivery of turbines and payments, for delays in delivery and for failure to meet performance obligations and warranty agreements. EME's reliance on these contractual provisions is subject to credit risks. Generally, these are unsecured obligations of the turbine manufacturer. A material adverse development with respect to a turbine supplier may have a material impact on EME's wind projects.

Edison Capital's investments may be affected by the financial condition of other parties, the performance of the asset, economic conditions and other business and legal factors. Edison Capital generally does not control operations or management of the projects in which it invests and must rely on the skill, experience and performance of third party project operators or managers. These third parties may experience financial difficulties or otherwise become unable or unwilling to perform their obligations. Edison Capital's investments generally depend upon the operating results of a project with a single asset. These results may be affected by general market conditions, equipment or process failures, disruptions in important fuel supplies or prices, or another party's failure to perform material contract obligations, and regulatory actions affecting utilities purchasing power from the leased assets. Edison Capital has taken steps to mitigate these risks in the structure of each project through contract requirements, warranties, insurance, collateral rights and default remedies, but such measures may not be adequate to assure full performance. In the event of default, lenders with a security interest in the asset may exercise remedies that could lead to a loss of some or all of Edison Capital's investment in that asset.

At December 31, 2008, Edison Capital had a net leveraged lease investment, before deferred taxes, of $50 million in three aircraft leased to American Airlines. American Airlines reported net losses during 2008 and previously reported losses for a number of years prior to 2006. A default in the leveraged lease by American Airlines could result in a loss of some or all of Edison Capital's lease investment. At December 31, 2008, American Airlines was current in its lease payments to Edison Capital.

Interest Rate Risk

Interest rate changes can affect earnings and the cost of capital for capital improvements or new investments in power projects. EMG 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, a 100-basis-point change in interest rates at December 31, 2008 would increase or decrease EME's 2009 annual income before taxes by approximately $9 million. The fair market values of long-term fixed interest rate obligations are subject to interest rate risk. The fair market value of EMG's consolidated long-term obligations (including current portion) was $4.1 billion at December 31, 2008, compared to the carrying value of $4.8 billion. A 10% increase in market interest rates at December 31, 2008 would result in a decrease in the fair value of EMG's consolidated long-term obligations by approximately $185 million. A 10% decrease in market interest rates at December 31, 2008 would result in an increase in the fair value of EMG's consolidated long-term obligations by approximately $203 million.

Other Risks

At December 31, 2008, Edison Capital had an investment balance of $33 million in three separate funds that invest in infrastructure assets in Latin America, Asia and countries in Europe with emerging economies and a direct investment of $2 million in one company in Latin America. For some fund investments, there may be foreign currency exchange rate risk. Edison Capital records its share of earnings from these investments on a three-month lag. Due to significant declines in global equity valuations since September 30, 2008, Edison Capital is exposed to market to market losses of the underlying investments for period subsequent to September 30, 2008. As Edison Capital has no ongoing equity contribution obligations, the maximum exposure to losses is equal to the amount of its investments.

Edison Capital's cross-border leases are denominated in U.S. dollars and, therefore, are not exposed to foreign currency rate risk.

EDISON INTERNATIONAL (PARENT)

EDISON INTERNATIONAL (PARENT): LIQUIDITY

The parent company's liquidity and its ability to pay interest and principal on debt, if any, operating expenses and dividends to common shareholders are affected by dividends and other distributions from subsidiaries, tax-allocation payments under its tax-allocation agreements with its subsidiaries, and access to bank and capital markets. As a response to significant disruption in the credit and capital markets, Edison International borrowed against its credit facility in September 2008. The proceeds were invested in U.S. treasury bills and U.S. treasury and government agency money market funds. At December 31, 2008, Edison International (parent) had approximately $320 million of cash and cash equivalents on hand.

On March 12, 2008, Edison International (parent) amended its existing $1.5 billion credit facility, extending the maturity to February 2013 while retaining existing borrowing costs as specified in the facility. The amendment also provides four extension options which, if all exercised, and agreed to by lenders, will result in a final termination of February 2017.

A subsidiary of Lehman Brothers Holdings, Lehman Brothers Bank, FSB, is one of the lenders in Edison International's (parent) credit agreement representing a total commitment of $74 million. On September 15, 2008, Lehman Brothers Holdings filed for protection under Chapter 11 of the U.S. Bankruptcy Code. Lehman Brothers Bank, FSB, fully funded $12 million of Edison International's (parent) borrowing request, which remains outstanding.

The following table summarizes the status of the Edison International (parent) credit facility at December 31, 2008:

In millions	Edison International (parent)
Commitment	$ 1,500
Less: Unfunded commitment from Lehman Brothers subsidiary	(62)
	1,438
Outstanding borrowings	(250)
Outstanding letters of credit	—
Amount available	**$ 1,188**

Edison International (parent)'s cash requirements for the 12-month period following December 31, 2008 are expected to consist of:

- Dividends to common shareholders. The Board of Directors of Edison International declared a $0.31 per share quarterly dividend in December 2008 which was paid in January 2009. This quarterly dividend represents an increase of $0.005 per share over dividends paid in 2008. The dividend increase is consistent with Edison International's dividend policy of paying out approximately 45% to 55% of the earnings of SCE and balancing dividend increases with the significantly growing capital needs of Edison International's business;
- Maturity and interest payments on debt outstanding under the credit facility;
- Intercompany related debt; and
- General and administrative expenses.

Edison International (parent) expects to meet its 2009 continuing obligations through cash and cash equivalents on hand, external borrowings, tax-allocation payments under its tax-allocation agreements with its subsidiaries, and a $100 million SCE dividend paid in January 2009. Edison International does not expect to receive further dividends from its subsidiaries in 2009.

EDISON INTERNATIONAL (PARENT): OTHER DEVELOPMENTS

Federal and State Income Taxes

Edison International files its federal income tax returns on a consolidated basis and files on a combined basis in California and certain other states. See "Other Developments — Federal and State Income Taxes" for further discussion of these matters.

EDISON INTERNATIONAL (CONSOLIDATED)

RESULTS OF OPERATIONS AND HISTORICAL CASH FLOW ANALYSIS

Edison International's reportable segments include its electric utility operations (SCE), nonutility power generation activities (EME), financial services and other (Edison Capital and EMG nonutility subsidiaries) and parent and other (includes amounts from Edison International (parent), other Edison International nonutility subsidiaries that are not significant as a reportable segment, as well as intercompany eliminations). Included in the nonutility power generation segment are the activities of MEHC, the holding company of EME. MEHC's only substantive activities were its obligations under senior secured notes which were paid in full on June 25, 2007. MEHC does not have any substantive operations.

In millions	2008	2007	2006
Electric utility	**$ 683**	$ 707	$ 776
EMG:			
Nonutility power generation	**501**	340	344
Financial services and other	**60**	70	88
Parent and other	**(29)**	(19)	(27)
Edison International Net Income	**$ 1,215**	$ 1,098	$ 1,181

Electric Utility Net Income

In millions	2008	2007	2006
Electric utility operating revenue	**$ 11,248**	$ 10,233	$ 9,859
Fuel	**1,400**	1,191	1,112
Purchased power	**3,845**	3,235	3,099
Other operation and maintenance	**3,245**	3,055	2,843
Depreciation, decommissioning and amortization	**1,114**	1,011	950
Contract buyout/termination and other	**(9)**	—	(1)
Total operating expenses	**9,595**	8,492	8,003
Operating income	**1,653**	1,741	1,856
Interest and dividend income	**22**	44	58
Other nonoperating income	**101**	89	85
Interest expense – net of amount capitalized	**(407)**	(429)	(399)
Other nonoperating deductions	**(123)**	(45)	(60)
Income from continuing operations before tax and minority interest	**1,246**	1,400	1,540
Income tax expense	**342**	337	438
Dividends on preferred and preference stock of utility not subject to mandatory redemption	**51**	51	51
Minority interest	**170**	305	275
Income from continuing operations	**683**	707	776
Income (loss) from discontinued operations – net of tax	**—**	—	—
Income before accounting change	**683**	707	776
Cumulative effect of accounting change – net of tax	**—**	—	—
Electric Utility Net Income	**$ 683**	$ 707	$ 776

SCE has variable interests in contracts with certain QFs that contain variable contract pricing provisions based on the price of natural gas. Four of these contracts are with entities that are partnerships owned in part by

EME. The QFs sell electricity to SCE and steam to nonrelated parties. As required by FIN 46(R), SCE consolidates these Big 4 projects. See "— Nonutility power generation operating income" for a discussion related to the Big 4 projects.

Electric Utility Operating Revenue

The following table sets forth the major components of electric utility revenue:

In millions	2008	2007	2006
Electric utility revenue			
Retail billed and unbilled revenue	**$ 9,307**	$ 9,213	$ 9,639
Balancing account (over)/under collections	**568**	(270)	(891)
Sales for resale	**580**	489	369
Big 4 projects (SCE's VIEs)[1]	**409**	379	385
Other (including intercompany transactions)	**384**	422	357
Total	**$ 11,248**	$ 10,233	$ 9,859

(1) See "— Nonutility power generation operating income" for a discussion related to the Big 4 projects.

SCE's retail sales represented approximately 88%, 87% and 88% of electric utility revenue for the years ended December 31, 2008, 2007 and 2006, respectively. Due to warmer weather during the summer months and SCE's rate design, electric utility revenue during the third quarter of each year is generally higher than other quarters. Of total electric utility revenue, $6.7 billion, $5.3 billion, and $5.5 billion was used to collect costs subject to balancing account treatment in 2008, 2007 and 2006, respectively.

Total electric utility revenue increased by $1 billion in 2008 compared to 2007. The variances for the revenue components are as follows:

- Retail billed and unbilled revenue increased $94 million in 2008, compared to the same period in 2007. The increase reflects a rate increase (including impact of tiered rate structure) of $92 million and a sales volume increase of $2 million. The rate increase was due to minor variations of usage by rate class.
- SCE's revenue requirement provides recovery of pass-through costs under ratemaking mechanisms (balancing accounts) authorized by the CPUC. The revenue requirement for pass-through costs provides recovery of fuel and purchased-power expenses, demand-side management programs, nuclear decommissioning, public purpose programs, certain operation and maintenance expenses and depreciation expense related to certain projects. SCE recognizes revenue equal to actual costs incurred for pass-through costs. In 2008, SCE accrued $568 million of revenue above the authorized revenue requirement compared to a deferral of revenue of $270 million in 2007. The 2008 accrual is due to higher purchased power and fuel costs experienced during the year compared to levels authorized in rates (see "— Purchased-Power Expense" and "— Fuel Expense" for further information).
- Sales for resale represent the sale of excess energy. Excess energy from SCE sources which may exist at certain times is resold in the energy markets. Sales for resale revenue increased for 2008 due to higher excess energy in 2008 compared to the same period in 2007, resulting from increased kWh purchases from new contracts, as well as increased sales from least cost dispatch energy. Revenue from sales for resale is refunded to customers through the ERRA balancing account and does not impact earnings.

Total electric utility revenue increased by $374 million in 2007 compared to 2006 (as shown in the table above). The variances for the revenue components are as follows:

- Retail billed and unbilled revenue decreased $426 million in 2007, compared to the same period in 2006. The decrease reflects a rate decrease (including impact of tiered rate structure) of $545 million offset by a sales volume increase of $119 million. Electric utility revenue from rate changes decreased mainly from the redesign of SCE's tiered rate structure which resulted in a decrease of residential rates in the higher tiers. Effective February 14, 2007, SCE's system average rate decreased to 13.9¢ per-kWh (including 3.0¢ per-kWh related to CDWR) mainly as the result of projected lower natural gas prices in 2007, as well as the refund of overcollections in the ERRA balancing account that occurred in 2006 from lower than expected natural gas prices and higher than expected summer 2006 sales volume. Electric utility revenue resulting from sales volume changes was mainly due to customer growth as well as an increase in customer usage.

- SCE's revenue requirement provides recovery of pass-through costs under ratemaking mechanisms (balancing accounts) authorized by the CPUC. The revenue requirement for pass-through costs provides recovery of fuel and purchased-power expenses, demand-side management programs, nuclear decommissioning, public purpose programs, certain operation and maintenance expenses and depreciation expense related to certain projects. SCE recognizes revenue equal to actual costs incurred for pass-through costs. In 2007, SCE deferred approximately $270 million compared to a deferral of approximately $891 million in 2006. The decrease in deferred revenue was mainly due to lower purchased power and fuel costs experienced during 2007, compared to levels authorized in rates, resulting from warmer weather in 2006 (see "— Purchased-Power Expense" and "— Fuel Expense" for further information).
- Electric utility revenue from sales for resale represents the sale of excess energy. Excess energy from SCE sources which may exist at certain times is resold in the energy markets. Sales for resale revenue increased due to higher excess energy in 2007, compared to 2006. Revenue from sales for resale is refunded to customers through the ERRA balancing account and does not impact earnings.

Amounts SCE bills and collects from its customers for electric power purchased and sold by the CDWR to SCE's customers, CDWR bond-related costs and a portion of direct access exit fees are remitted to the CDWR and are not recognized as revenue by SCE. The amounts collected and remitted to CDWR were $2.2 billion, $2.3 billion and $2.5 billion for the years ended December 31, 2008, 2007 and 2006, respectively.

Fuel Expense

In millions **For The Year Ended December 31,**	**2008**	**2007**	**2006**
SCE	**$ 587**	$ 482	$ 389
Big 4 projects (SCE's VIEs)[1]	**813**	709	723
Total fuel expense	**$ 1,400**	$ 1,191	$ 1,112

[1] See "— Nonutility Power Generation Operating Income" for information regarding the Big 4 projects.

SCE's fuel expense increased $105 million in 2008 and $93 million in 2007. The 2008 increase was mainly due to an $85 million increase at SCE's Mountainview plant resulting from higher gas costs in 2008. The 2007 increase was mainly due to a $70 million increase at SCE's Mountainview plant due to higher generation and higher gas costs in 2007; and a $20 million increase in nuclear fuel expense in 2007 resulting from higher generation in 2007 due to a 2006 planned refueling and maintenance outage at SCE's San Onofre Units 2 and 3.

Purchased-Power Expense

In millions **For The Year Ended December 31,**	**2008**	**2007**	**2006**
Purchased-power	**$ 3,816**	$ 3,179	$ 2,940
Realized losses on economic hedging activities – net	**60**	132	339
Energy settlements and refunds	**(31)**	(76)	(180)
Total purchased-power expense	**$ 3,845**	$ 3,235	$ 3,099

SCE's total purchased-power expense increased $610 million in 2008 and $136 million in 2007.

Purchased-power, in the table above, increased $637 million in 2008 and $239 million in 2007. The 2008 increase was due to: higher bilateral energy purchases of $360 million, resulting from higher costs per kWh due to higher gas prices and increased kWh purchases; higher QF purchased-power expense of $135 million, resulting from increased kWh purchases and an increase in the average spot natural gas prices for certain contracts; and higher ISO-related energy costs of $165 million. These increases were partially offset by $30 million of lower firm transmission rights costs. The 2007 increase was due to higher bilateral energy purchases of $230 million, resulting from higher costs per kWh and increased kWh purchases from new contracts entered into in 2007; higher QF purchased-power expense of $105 million, resulting from an increase in the average spot natural gas prices (as discussed further below); and higher firm transmission right costs of $50 million. The 2007 increase was partially offset by a decrease in ISO-related energy costs of $150 million.

SCE's realized gains and losses arising from derivative instruments are reflected in purchased-power expense and are recovered through the ERRA mechanism. Unrealized gains and losses have no impact on purchased-power expense due to regulatory mechanisms. As a result, realized and unrealized gains and losses do not affect earnings, but may temporarily affect cash flows. Realized losses on economic hedging were $60 million in 2008, $132 million in 2007, and $339 million in 2006. Unrealized (gains) losses on economic hedging were $638 million in 2008, $(91) million in 2007, and $237 million in 2006. Changes in realized and unrealized gains and losses on economic hedging activities were primarily due to significant decreases in forward natural gas prices in 2008 compared to 2007. Changes in realized and unrealized gains and losses on economic hedging activities in 2007 compared to 2006 were primarily due to changes in SCE's gas hedge portfolio mix as well as an increase in the natural gas futures market in 2007. (See "SCE: Market Risk Exposures — Commodity Price Risk" for further discussion).

SCE received energy settlements and refunds (including generator settlements) of $31 million in 2008, $76 million in 2007 and $180 million in 2006. Certain of these refunds are from sellers of electricity and natural gas who manipulated the electric and natural gas markets during the energy crisis in California in 2000 – 2001 or who benefited from the manipulation by receiving inflated market prices. SCE is required to refund to customers 90% of any refunds actually realized by SCE for these types of refunds, net of litigation costs, and 10% will be retained by SCE as a shareholder incentive.

Federal law and CPUC orders required SCE to enter into contracts to purchase power from QFs at CPUC-mandated prices. Energy payments to gas-fired QFs are generally tied to spot natural gas prices. Energy payments for most renewable QFs are at a fixed price of 5.37¢ per-kWh. In late 2006, certain renewable QF contracts were amended and energy payments for these contracts are at a fixed price of 6.15¢ per-kWh, effective May 2007.

Other Operation and Maintenance Expense

SCE's other operation and maintenance expense increased $190 million in 2008 and increased $212 million in 2007. Other operating and maintenance expenses related to regulatory balancing accounts increased $70 million in 2008 compared to 2007, mainly related to higher demand-side management costs and energy efficiency costs. These accounts are recovered through regulatory mechanisms approved by the CPUC and do not impact earnings. The increase in operation and maintenance expense in 2008 also reflects: higher administrative and general costs of $35 million; higher generation expenses of $60 million related to maintenance and refueling outage expenses at San Onofre and higher overhaul and outage costs at Four Corners and Palo Verde; higher generation expenses of $20 million at Mountainview; and higher customer service costs of $15 million; and higher employer payroll taxes and property taxes of $15 million. The 2008 variance also reflects a decrease of approximately $30 million related to lower transmission and distribution maintenance costs. The 2007 increase reflects $98 million of higher costs associated with certain operation and maintenance expense accounts recovered through regulatory mechanisms approved by the CPUC. These costs were mainly related to both higher demand-side management and energy efficiency costs partially offset by lower must-run and must-offer obligation costs related to the reliability of the ISO systems. The 2007 increase was also due to higher transmission and distribution maintenance costs of approximately $20 million; higher health care costs and other benefits of $30 million; higher generation expenses of $20 million at Mountainview; higher uncollectible accounts of $10 million; and higher legal costs of $20 million. The 2007 increase was partially offset by lower generation-related costs of approximately $20 million in 2007 resulting from the planned refueling and maintenance outages at SCE's San Onofre Units 2 and 3 in the first quarter of 2006.

Depreciation, Decommissioning and Amortization Expense

SCE's depreciation, decommissioning and amortization expense increased $103 million in 2008 and increased $61 million in 2007. The 2008 increase was primarily due to $90 million increased depreciation resulting from additions to transmission and distribution assets (see "SCE: Liquidity — Capital Expenditures" for a further discussion); and a $17 million cumulative depreciation rate adjustment recorded in the second quarter of 2008. The 2007 increase was primarily due to $50 million increased depreciation resulting from additions to transmission and distribution asset additions (see "SCE: Liquidity — Capital Expenditures" for a further discussion).

Interest Income

SCE's interest income decreased $22 million in 2008 and $14 million in 2007. The 2008 and 2007 decreases were mainly due to lower undercollection balances in certain balancing accounts and lower interest rates applied to those undercollections.

Other Nonoperating Income

SCE's other nonoperating income increased $12 million in 2008. The 2008 increase was due to receipt of corporate-owned life insurance proceeds and an increase in allowance for funds used during construction – equity resulting from an increase in construction work in progress due to planned capital expenditures (see SCE: Liquidity — Capital Expenditures" for further discussion). The increase was partially offset by payments received in the third quarter of 2007 for settlement of claims related to the natural gas purchased contracts for one of SCE's VIE projects.

Interest Expense – Net of Amounts Capitalized

SCE's interest expense – net of amounts capitalized decreased $22 million in 2008 and increased $30 million in 2007. The 2008 decrease was mainly due to lower over-collections of certain balancing accounts and lower interest rates applied to those over-collections during 2008, compared to 2007. This 2008 decrease was partially offset by higher interest expense on short-term debt and long-term debt resulting from higher balances compared to the same period in 2007. The 2007 increase was mainly due to higher interest expense on balancing account overcollections in 2007, as compared to 2006, and higher interest expense on long-term debt resulting from higher balances outstanding during 2007, as compared to 2006.

Other Nonoperating Deductions

SCE's other nonoperating deductions increased $78 million in 2008 and decreased $15 million in 2007. The 2008 increase primarily resulted from a CPUC decision in September 2008 related to SCE incentives claimed under a CPUC-approved PBR mechanism. The decision required SCE to refund $28 million and $20 million related to customer satisfaction and employee safely reporting incentives, respectively, and further required SCE to forego claimed incentives of $20 million and $15 million related to customer satisfaction and employee safety reporting, respectively. The decision also required SCE to refund $33 million for employee bonuses related to the program and imposed a statutory penalty of $30 million. During the third quarter of 2008, SCE recorded a charge of $49 million, after-tax ($60 million, pre-tax) in the consolidated statements of income related to this decision. The 2008 increase in other nonoperating deductions was also due to approximately $10 million for expenditures related to civic, political and related activities, and donations. The 2007 decrease was mainly due to a penalty accrual of $23 million under the customer satisfaction performance mechanism discussed above which was recognized in 2006.

Income Taxes

The composite federal and state statutory income tax rate was approximately 40% (net of the federal benefit for state income taxes) for all periods presented. The lower effective tax rate of 31.8% realized in 2008 as compared to the statutory rate was primarily due to software and property related flow through deductions. The lower effective tax rate of 30.8% realized in 2007 as compared to the statutory rate was primarily due to reductions made to the income tax reserve to reflect progress made in an administrative appeals process with the IRS related to the income tax treatment of certain costs associated with environmental remediation and to reflect an audit settlement of state tax issues. The lower effective tax rate of 34.6% realized in 2006 as compared to the statutory rate was primarily due to a settlement reached with the California Franchise Tax Board regarding a state apportionment issue partially offset by tax reserve accruals.

Nonutility Power Generation Net Income

The following table sets forth the major changes in nonutility power generation net income:

In millions	2008	2007	2006
Nonutility power generation operating revenue	**$ 2,811**	$ 2,580	$ 2,239
Fuel	**747**	684	645
Other operation and maintenance	**1,004**	969	827
Depreciation, decommissioning and amortization	**194**	162	144
Contract buyout/termination and other	**14**	1	—
Total operating expenses	**1,959**	1,816	1,616
Operating income	**852**	764	623
Interest and dividend income	**36**	98	98
Equity in income from partnerships and unconsolidated subsidiaries – net	**122**	200	186
Other nonoperating income	**12**	6	26
Interest expense – net of amounts capitalized	**(279)**	(313)	(393)
Other nonoperating deductions	—	—	(3)
Loss on early extinguishment of debt	—	(241)	(146)
Income from continuing operations before tax and minority interest	**743**	514	391
Income tax expense	**243**	173	145
Minority interest	—	(1)	(1)
Income from continuing operations	**500**	342	247
Income (loss) from discontinued operations – net of tax	**1**	(2)	97
Income before accounting change	**501**	340	344
Cumulative effect of accounting change – net of tax	—	—	—
Net income	**$ 501**	$ 340	$ 344

Nonutility Power Generation Operating Income

EME operates in one line of business, independent power production. Operating revenues are primarily derived from the sale of energy and capacity from the Illinois Plants and the Homer City facilities. Equity in income from unconsolidated affiliates primarily 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 adjusted operating income (loss) as described below.

The following section and table provides a summary of results of EME's operating projects and corporate expenses for the three years ended December 31, 2008, together with discussions of the contributions by specific projects and of other significant factors affecting these results. EME has modified its internal reporting of project profitability using a new performance measure entitled adjusted operating income. Previously, EME used pre-tax income adjusted for production tax credits to measure the profitability of projects. The change in measurement to adjusted operating income was made to improve the comparison of performance excluding financing costs which may be at different entities throughout the corporate hierarchy, but do not affect the operating profitability of a project.

The following table shows the adjusted operating income of EME's projects:

In millions	2008	2007	2006
Illinois Plants	**$ 688**	$ 583	$ 463
Homer City	**202**	221	150
Renewable energy projects	**59**	30	19
Energy trading	**164**	142	130
Big 4 projects	**87**	147	136
Sunrise	**24**	33	34
Westside projects	**9**	11	11
Doga	**8**	14	—
Other non-wind projects	**14**	14	6
Other	**(31)**	(7)	11
	1,224	1,188	960
Corporate administrative and general	**(172)**	(169)	(108)
Corporate depreciation and amortization	**(12)**	(8)	(4)
Adjusted Operating Income[1]	**$ 1,040**	$ 1,011	$ 848

The following table reconciles adjusted operating income to operating income as reflected on EME's consolidated statements of income:

In millions	2008	2007	2006
Adjusted Operating Income	**$ 1,040**	$ 1,011	$ 848
Less:			
Equity in earnings of unconsolidated affiliates	**122**	200	186
Dividend income from projects	**10**	12	2
Production tax credits	**44**	29	16
Other income (expense), net	**12**	6	21
Operating Income	**$ 852**	$ 764	$ 623

(1) Adjusted operating income is equal to operating income under GAAP, plus equity in earnings of unconsolidated affiliates, dividend income from projects, production tax credits and other income and expenses. Production tax credits are recognized as wind energy is generated based on a per-kilowatt-hour rate prescribed in applicable federal and state statutes. Adjusted operating income is a non-GAAP performance measure and may not be comparable to those of other companies. Management believes that inclusion of earnings of unconsolidated affiliates, dividend income from projects, production tax credits and other income and expenses in adjusted operating income is more meaningful for investors as these components are integral to the operating results of EME.

Illinois Plants

The following table presents additional data for the Illinois Plants:

In millions	2008	2007	2006
Operating Revenues	**$ 1,778**	$ 1,579	$ 1,399
Operating Expenses			
Fuel[1]	**482**	400	382
Gain on sale of emission allowances[2]	**(3)**	(18)	(16)
Plant operations	**434**	420	369
Plant operating leases	**75**	75	75
Depreciation and amortization	**106**	99	101
(Gain) on buyout of contract and (gain) loss on sale of assets	**(16)**	—	4
Administrative and general	**22**	22	19
Total operating expenses	**1,100**	998	934
Operating Income	**678**	581	465
Other Income (Expense)	**10**	2	(2)
Adjusted Operating Income[3]	**$ 688**	$ 583	$ 463
Statistics			
Generation (in GWh):			
Energy only contracts	**26,010**	22,503	28,898
Load requirements services contracts[4]	**5,090**	7,458	—
Total	**31,100**	29,961	28,898
Aggregate plant performance:			
Equivalent availability[5]	**81.0%**	75.8%	79.3%
Capacity factor[6]	**64.8%**	60.9%	58.8%
Load factor[7]	**80.0%**	80.4%	74.1%
Forced outage rate[8]	**8.3%**	9.7%	7.9%
Average realized price/MWh:			
Energy only contracts[9]	**$ 51.82**	$ 48.79	$ 46.19
Load requirements services contracts[10]	**$ 62.64**	$ 63.43	$ —
Capacity revenue only (in millions)	**$ 111**	$ 27	$ 24
Average fuel costs/MWh	**$ 15.49**	$ 13.36	$ 13.19

(1) The Illinois Plants purchased NO_X emission allowances from the Homer City facilities at fair market value. Purchases were $0.4 million in 2007 and $6 million in 2006. These purchases are included in fuel costs. There were no purchases in 2008.

(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 $2 million in 2008, $21 million in 2007 and $14 million in 2006. These sales reduced operating expenses. EME recorded $3 million of intercompany profit during 2008 consisting of $1 million and $2 million on emission allowances sold by the Illinois Plants to the Homer City facilities during the first quarter of 2008 and the fourth quarter of 2007, respectively, but not yet used by the Homer City facilities until the second quarter of 2008 and the first quarter of 2008, respectively. In addition, EME recorded $4 million of intercompany profit during 2007 that was eliminated by EME in 2006 on emission allowances sold by the Illinois Plants to the Homer City facilities in the fourth quarter of 2006 but not used by the Homer City facilities until the first quarter of 2007. 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.

(3) As described above, adjusted operating income is equal to operating income plus other income (expense). Adjusted operating income is a non-GAAP performance measure and may not be comparable to those of other companies. Management believes that inclusion of other income (expense) is more meaningful for investors as the components of other income (expense) are integral to the results of the Illinois Plants.

(4) Represents two load requirements services contracts, awarded as part of an Illinois auction, with Commonwealth Edison that commenced on January 1, 2007, one of which expired in May 2008 and the remaining contract is scheduled to expire in May 2009.

(5) The equivalent availability factor is defined as the number of MWh 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.

(6) The capacity factor is defined as the actual number of MWh 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.

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

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

(9) 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) generation as shown in the table below. Revenue related to capacity sales are excluded from the calculation of average realized energy price.

In millions **Years Ended December 31,**	**2008**	2007	2006
Operating revenues	**$ 1,778**	$ 1,579	$ 1,399
Less:			
Load requirements services contracts	**(319)**	(473)	—
Unrealized losses (gains)	**6**	25	(30)
Capacity and other revenues	**(117)**	(33)	(34)
Realized revenues	**$ 1,348**	$ 1,098	$ 1,335
Generation (in GWh)	**26,010**	22,503	28,898
Average realized energy price/MWh	**$ 51.82**	$ 48.79	$ 46.19

(10) The average realized price reflects the contract price for sales to Commonwealth Edison under load requirements services contracts that include energy, capacity and ancillary services. It is determined by dividing (i) contract revenue less PJM operating and ancillary charges by (ii) generation.

Earnings from the Illinois Plants increased $105 million in 2008 compared to 2007, and $120 million in 2007 compared to 2006. The 2008 increase in earnings was primarily attributable to higher realized gross margin, an increase in unrealized gains related to hedge contracts (described below) and a $15 million gain recorded during the first quarter of 2008 related to a buyout of a fuel contract. See "Commitments, Guarantees and Indemnities — Fuel Supply Contracts" for further discussion. The increase in realized gross margin was due to an increase in capacity prices as a result of the PJM RPM auction. The increase in generation and slightly higher average realized energy prices was partially offset by higher coal and transportation costs. The 2008 increase in earnings was also partially offset by a $24 million charge related to power contracts due to the bankruptcy of Lehman Brothers Holdings described below.

Two factors are expected to increase operating expenses by approximately $90 million to $105 million during 2009 as compared to 2008:

- Effective January 1, 2009, the CAIR requires Midwest Generation to purchase annual NO_X allowances in excess of the amounts allocated by the state of Illinois under its SIP. See "Other Developments —

Environmental Matters — Air Quality Regulation — Clean Air Interstate Rule — Illinois" for further discussion.

- Midwest Generation installed activated carbon injection equipment to reduce mercury emissions at the Illinois Plants.

The 2007 increase in earnings was primarily attributable to higher energy revenues resulting from higher average realized energy prices and slightly higher generation as compared to 2006. Partially offsetting these increases were higher planned maintenance costs, unplanned outages at the Powerton Station and a $7.5 million payment during the third quarter of 2007 related to the settlement agreement with the Illinois Attorney General. Earnings were also adversely affected by an increase in unrealized losses in 2007 related to power contracts described below.

Included in operating revenues were unrealized gains (losses) of $(6) million, $(25) million and $30 million in 2008, 2007 and 2006, respectively. In 2008, unrealized losses included $24 million from power contracts for 2009 and 2010 with Lehman Brothers Commodity Services, Inc. These contracts qualified as cash flow hedges under SFAS No. 133 until EME dedesignated the contracts due to non-performance risk and subsequently terminated the contracts. The change in fair value was recorded as an unrealized loss during 2008. Unrealized gains (losses) were also attributable to the ineffective portion of forward and futures contracts which are derivatives that qualify as cash flow hedges under SFAS No. 133 and 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 2007, power prices increased, resulting in mark-to-market losses on economic hedges. See "EMG: Market Risk Exposures — Commodity Price Risk" and "EMG: Market Risk Exposures — Accounting for Energy Contracts" for more information regarding forward market prices and the write-off of the power contracts, respectively.

Powerton Station Outage —

On December 18, 2007, Unit 6 at the Powerton Station had a duct failure resulting in a suspension of operations at this unit through February 12, 2008. Scheduled maintenance work for the spring of 2008 was accelerated to minimize the aggregate impact of the outage. The duct failure resulted in claims under Midwest Generation's property and business interruption insurance policies. During the first quarter of 2008, $6 million related to business interruption insurance coverage was recorded primarily related to these claims reflected in other nonoperating income on Edison International's consolidated statements of income. At December 31, 2008, Midwest Generation had a $4 million receivable recorded related to these claims.

Homer City

The following table presents additional data for the Homer City facilities:

In millions	2008	2007	2006
Operating Revenues	**$ 717**	$ 764	$ 642
Operating Expenses			
Fuel[1]	**270**	306	283
Gain on sale of emission allowances[2]	**—**	—	(7)
Plant operations	**126**	119	106
Plant operating leases	**102**	102	102
Depreciation and amortization	**16**	14	16
Administrative and general	**4**	4	5
Total operating expenses	**518**	545	505
Operating Income	**199**	219	137
Other Income	**3**	2	13
Adjusted Operating Income[3]	**$ 202**	$ 221	$ 150
Statistics			
Generation (in GWh)	**11,334**	13,649	12,286
Equivalent availability[4]	**80.7%**	89.4%	81.9%
Capacity factor[5]	**68.3%**	82.5%	74.3%
Load factor[6]	**84.6%**	92.4%	90.7%
Forced outage rate[7]	**9.8%**	4.1%	13.5%
Average realized energy price/MWh[8]	**$ 56.24**	$ 54.40	$ 48.02
Capacity revenue only (in millions)	**$ 46**	$ 30	$ 16
Average fuel costs/MWh	**$ 23.35**	$ 22.45	$ 23.05

(1) The Homer City facilities purchased SO_2 emission allowances from the Illinois Plants at fair market value. Purchases were $2 million in 2008, $21 million in 2007 and $14 million in 2006. 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 $0.4 million in 2007 and $6 million in 2006. There were no sales in 2008. The 2007 and 2006 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) As described above, adjusted operating income is equal to operating income plus other income. Adjusted operating income is a non-GAAP performance measure and may not be comparable to those of other companies. Management believes that inclusion of other income is more meaningful for investors as the components of other income are integral to the results of the Homer City facilities.

(4) The equivalent availability factor is defined as the number of MWh 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.

(5) The capacity factor is defined as the actual number of MWh 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.

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

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

(8) 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 as shown in the table below. Revenue related to capacity sales are excluded from the calculation of average realized energy price.

In millions **Years Ended December 31,**	**2008**	2007	2006
Operating revenues	**$ 717**	$ 764	$ 642
Less:			
Unrealized losses (gains)	**(21)**	10	(35)
Capacity and other revenues	**(59)**	(31)	(17)
Realized revenues	**$ 637**	$ 743	$ 590
Generation (in GWh)	**11,334**	13,649	12,286
Average realized energy price/MWh	**$ 56.24**	$ 54.40	$ 48.02

Earnings from Homer City decreased $19 million in 2008 compared to 2007 and increased $71 million in 2007 compared to 2006. The 2008 decrease in earnings was primarily attributable to lower realized gross margin and higher plant maintenance expenses, partially offset by an increase in unrealized gains related to hedge contracts (described below). The decline in realized gross margin was primarily due to lower generation from higher forced outages, lower off-peak dispatch and extended planned overhauls in 2008, partially offset by an increase in capacity revenues and the sale of excess coal inventory. Included in fuel costs were $19 million, $31 million and $35 million in 2008, 2007 and 2006, 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 2007 increase in earnings was primarily attributable to an increase in energy revenues from higher generation and average realized energy prices, and an increase in capacity revenues resulting from the PJM RPM auction. Partially offsetting these increases were higher maintenance costs in 2007 related to the planned outage at Unit 2 of the Homer City facilities and lower other income in 2007 for the estimated insurance recovery related to the Unit 3 outage of approximately $3 million recorded during the third quarter of 2007, compared to approximately $11 million recorded during the second quarter of 2006, reflected in other income (expense), net on EME's consolidated statements of income. Earnings for 2007 were also adversely affected due to the timing of unrealized gains and losses related to hedge contracts discussed below.

Included in operating revenues were unrealized gains (losses) from hedge activities of $21 million, $(10) million and $35 million in 2008, 2007 and 2006, 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). See "EMG: Market Risk Exposures — Commodity Price Risk" and "EMG: Market Risk Exposures — Accounting for Energy Contracts" for more information regarding forward market prices and unrealized gains (losses), respectively.

The average realized energy price received by Homer City in 2008, 2007 and 2006 was $56.24/MWh, $54.40/MWh and $48.02/MWh, respectively, compared to the average real-time market price at the Homer City busbar for the same periods of $57.72/MWh, $51.03/MWh and $45.15/MWh, respectively. The average realized energy price for the twelve months ended December 31, 2008 was below the 24-hour PJM average market price at the Homer City busbar primarily due to effective hedge prices being below market prices for the same period. 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, (2) differences between market prices during periods of actual generation (generally weighted to on-peak periods) and the 24-hour average real-time market prices, and (3) 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. See "EMG: Market Risk Exposures — Commodity Price Risk — Basis Risk" and "Market Risk Exposures — Accounting for Energy Contracts."

Seasonal Disclosure

Due to higher electric demand resulting from warmer weather during the summer months and cold weather during the winter months, electric revenue 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 "EMG: 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.

Renewable Energy Projects

The following table presents additional data for EME's renewable energy projects:

In millions	2008	2007	2006
Operating Revenues	**$ 108**	$ 51	$ 30
Production Tax Credits	**44**	29	16
	152	80	46
Operating Expenses			
Plant operations	**35**	18	12
Depreciation and amortization	**59**	34	20
Administrative and general	**2**	1	—
Total operating expenses	**96**	53	32
Other Income	**3**	3	5
Adjusted Operating Income[1]	**$ 59**	$ 30	$ 19
Statistics			
Generation (in GWh)	**2,286**	1,533	897
Aggregate plant performance:			
Equivalent availability	**80.4%**	85.5%	96.1%
Capacity factor	**33.1%**	37.8%	34.1%

(1) Adjusted operating income is equal to operating income (loss) plus production tax credits and other income. 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 wind projects are recorded as a reduction in income taxes. Accordingly, adjusted operating income represents a non-GAAP performance measure which may not be comparable to those of other companies. Management believes that inclusion of production tax credits in adjusted operating income 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 adjusted operating income as shown above to operating income (loss) under GAAP:

In millions **Years Ended December 31,**	2008	2007	2006
Adjusted Operating Income	**$ 59**	$ 30	$ 19
Less:			
Production tax credits	**44**	29	16
Other income	**3**	3	5
Operating Income (Loss)	**$ 12**	$ (2)	$ (2)

EME has significantly expanded its renewable energy project portfolio during the past three years. EME's share of installed capacity of new wind projects that commenced operations during 2008 and 2007 was 396 MW and 292 MW, respectively. New projects that commenced operations were the primary drivers for increases in the revenues and operating costs and adjusted operating income.

EME's operating wind projects include 189 turbines manufactured by Suzlon Wind Energy Corporation (Suzlon). Rotor blade cracks were identified on certain of the Suzlon Model S88 wind turbines using V-2 blades, and Suzlon has advised EME that such cracks have also appeared on turbines with another Suzlon customer. Suzlon, with review and oversight from EME's technical experts, has completed its analysis and blade testing to determine the root cause of the blade crack issues and a remediation plan is being implemented. To address the commercial impact of these issues on EME and its projects, during the second quarter of 2008, EME signed an agreement with Suzlon providing EME with enhanced warranty and credit protections with respect to the Suzlon turbine issues including the rotor blade crack issues. The availability and capacity factors were adversely affected due to performance issues with the Suzlon turbines. However, under the terms of the turbine supply agreements, Suzlon has agreed to provide liquidated damages for unavailability of turbines. Revenues recognized for liquidated damages were $28 million in 2008 (of which $4 million related to 2007 generation).

In addition to the Suzlon turbines, EME has purchased 71 turbines from Clipper Turbine Works, Inc. (Clipper) of which 20 turbines are in service at the Jeffers wind project and 40 turbines are planned for the High Lonesome wind project currently under construction. EME recently learned that problems have been discovered in the blades on certain Clipper wind turbines. Root cause analysis to date has determined the blade problems resulted from a manufacturing defect. During the fourth quarter of 2008, EME signed an agreement with Clipper addressing procedures for remediation, enhanced warranties, and other protections with respect to the blades planned for the High Lonesome wind project. EME and Clipper are currently discussing a similar agreement with respect to the blades in service at the Jeffers project. EME expects to continue to work with Clipper to review the root cause analysis of the blade problems and necessary corrective actions, and to address commercial matters that result from the impact of these issues on its projects.

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 $164 million, $142 million and $130 million in 2008, 2007 and 2006, respectively. The 2008 increase in earnings from energy trading activities was primarily attributable to increased congestion and market volatility in key markets and gains from the Maryland contracts described below. The 2007 increase in earnings from energy trading activities was primarily attributable to increased congestion and market volatility in key markets and higher earnings from energy trading in the over-the-counter markets.

In April 2008, EMMT entered into three load services requirements contracts in Maryland with local utilities. Under the terms of the load services requirements contracts, EMMT is obligated to supply a portion of each utility's load at fixed prices that vary based on periods specified in the contracts. EMMT is obligated to pay for the cost of supply at each utility's load zones including, energy, capacity, ancillary services and renewable energy credits. The estimated load for the period of January 1, 2009 through September 30, 2010 is approximately 3.9 million MWh. EMMT has entered into futures contracts to substantially hedge the energy price risk related to these contracts. The above contracts are recorded as derivatives with the change in fair value reflected in trading income above.

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 were used, collectively, to secure financing by Edison Mission Energy Funding Corp., a special purpose entity. The Edison Mission Energy Funding Corp. financing was paid in full in September 2008. Due to similar economic characteristics, EME evaluates these projects collectively and refers to them as the Big 4 projects.

Earnings from the Big 4 projects decreased $60 million in 2008 compared to 2007, and increased $11 million in 2007 compared to 2006. The 2008 decrease in earnings was primarily due to $60 million in lower earnings from the Sycamore and Watson projects as a result of lower pricing in 2008 than previously applied under a long-term power sales agreement that expired. Two of EME's Big 4 projects (the Sycamore project and the Watson project) have power purchase agreements with SCE that have transitioned, or are in the process of transitioning, to new pricing terms. Under FIN 46(R), Edison International and SCE consolidate these projects due to SCE's variable interest in these entities. The Sycamore project's long-term contract with SCE expired on December 31, 2007. SCE contends that its long-term power purchase agreement with the Watson project also expired on December 31, 2007. The Watson project contends that the agreement expired in April 2008. The two projects are currently selling electricity to SCE under terms and conditions contained in their prior long-term power purchase agreements with revised pricing terms as mandated by the CPUC. Edison International expects that this arrangement will eventually be replaced by a new power purchase agreement between Watson and SCE, but cannot predict at this time whether or when this will occur. Any reduced costs to SCE resulting from these discussions will not impact SCE earnings because the savings flow through the regulatory recovery process to customers.

The 2007 change in earnings was primarily due to payments received in settlement of claims related to the natural gas purchase contracts during the second quarter of 2007 and outages at the Sycamore Cogeneration plant in 2006. Partially offsetting these increases were lower volumes sold in 2007 for the Kern River project.

The power sales agreement of the Midway-Sunset project is scheduled to expire in May 2009. Thereafter, Midway-Sunset expects to continue selling electricity either pursuant to a new power sales agreement or to SCE under the terms and conditions contained in its prior long-term power sales agreement, with revised pricing terms as mandated by the CPUC. The revised pricing terms are lower than the prices in the expiring power sales agreement. Furthermore, earnings for the Watson and Sycamore projects are expected to decrease in 2009 from 2008, due primarily to lower projected energy prices and volumes. Additionally, projected steam purchased from the hosts for the Sycamore and Midway-Sunset projects are expected to be lower in 2009. As a result of these factors, pre-tax earnings from the Big 4 projects are expected to decrease by approximately $45 million to $55 million during 2009.

Sunrise

Earnings from the Sunrise project decreased $9 million in 2008 from 2007 and $1 million in 2007 from 2006. The 2008 decrease was primarily due to lower availability incentive payments in 2008 and higher maintenance expenses due to unplanned outages in 2008. The 2007 decrease was primarily due to lower availability incentive payments partially offset by lower interest expense in 2007.

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.

Doga

Earnings from the Doga project decreased $6 million in 2008 compared to 2007 and increased $14 million in 2007 compared to 2006. Effective March 31, 2007, EME accounted for its ownership in the Doga project on the cost method (earnings are recognized when cash is distributed from the project). Earnings from Doga were higher in 2007 when EME's investment was fully recovered and earnings were recognized based on distributions received from the Doga project. Earnings from Doga during 2006 were adversely impacted by a change in Turkish corporate tax rates which reduced deferred tax assets (related to levelization of income from the power purchase agreement for financial reporting purposes).

Other Non-Wind Projects

Other non-wind projects increased $8 million in 2007 from 2006. The 2007 increase was primarily attributable to the improvement in the performance of EME's gas transportation agreement resulting from increased gas supply in the Rocky Mountain region which increased the market price of gas transportation into California.

Other

Other decreased $24 million in 2008 from 2007 and $18 million in 2007 from 2006. The 2008 decrease primarily resulted from a charge of $23 million related to the termination of a turbine supply agreement in connection with the Walnut Creek project. The 2007 decrease is partially attributable to a write-down of capitalized costs related to U.S. Wind Force. These amounts are reflected in "Gain on buyout of contract, loss on termination of contract, asset write-down and other charges and credits" on EME's consolidated statements of income. In addition, in 2006, EME recorded an $8 million gain related to receipt of shares from Mirant Corporation from a settlement of a claim recorded during the first quarter of 2006 reflected in other income (expense), net on EME's consolidated statements of income.

EME Administrative and General Expenses

EME corporate administrative and general expenses increased $3 million in 2008 from 2007 and $61 million in 2007 from 2006. The 2007 increase was primarily due to higher development costs incurred in 2007 (mostly related to wind projects), higher corporate expenses and a loss accrual related to legal proceedings recorded in the third quarter of 2007.

Interest Income

Interest income decreased $62 million in 2008 from 2007. The 2008 decrease was primarily attributable to lower interest rates in 2008 compared to 2007 and lower average cash equivalents and short-term investment balances. The 2007 decrease was primarily attributable to lower average cash balances in 2007 compared to 2006.

Interest Expense – Net of Amount Capitalized

Interest expense to third parties, before capitalized interest, decreased $34 million in 2008 from 2007 and $80 million in 2007 from 2006, respectively, primarily attributable to MEHC's redemption in full of its senior secured notes in June 2007 and EME's refinancing activities in May 2007. Capitalized interest increased $8 million in 2008 compared to 2007 and $16 million in 2007 compared to 2006. The increases were primarily due to wind projects under construction.

Loss on Early Extinguishment of Debt

Loss on early extinguishment of debt was $241 million in 2007 related to the early repayment of EME's 7.73% senior notes due June 15, 2009 and Midwest Generation's 8.75% second priority senior secured notes due May 1, 2034 and MEHC's 13.5% senior secured notes due July 15, 2008.

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.

Income Taxes

Income tax provision from continuing operations was $243 million in 2008, $173 million in 2007 and $145 million in 2006. Income tax benefits are recognized pursuant to a tax-allocation agreement with Edison International. See "EMG: Liquidity — Intercompany Tax-Allocation Agreement." EME recognized $44 million, $29 million and $16 million of production tax credits related to wind projects for the years ended

December 31, 2008, 2007 and 2006, respectively, and $5 million, $10 million and $14 million for each period related to estimated state income tax benefits allocated from Edison International.

Results of Discontinued Operations

Income (loss) from discontinued operations, net of tax, at EME was $1 million in 2008, $(2) million in 2007 and $98 million in 2006. The 2008 increase was due to adjustments for foreign exchange gains partially offset by interest expense associated with contract indemnities related to EME's sale of international projects in December 2004.

The 2007 decrease was largely attributable to distributions received from the Lakeland project (see "Discontinued Operations" for further discussion).

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 $686 million, $747 million and $756 million in 2008, 2007 and 2006, respectively.

Financial Services and Other Net Income

The following table sets forth the major changes in financial services net income:

In millions	2008	2007	2006
Financial services and other operating revenue	**$ 54**	$ 56	$ 70
Other operation and maintenance	**10**	13	15
Depreciation, decommissioning and amortization	**4**	9	13
Contract buyout/termination and other	**(49)**	2	—
Total operating expenses	**(35)**	24	28
Operating Income	**89**	32	42
Interest and dividend income	**12**	16	20
Equity in income from partnerships and unconsolidated subsidiaries – net	**(3)**	28	29
Other nonoperating income	**—**	2	22
Interest expense – net of amounts capitalized	**(9)**	(10)	(16)
Income from continuing operations before tax and minority interest	**89**	68	97
Income tax expense	**29**	(2)	9
Income from continuing operations	**60**	70	88
Income (loss) from discontinued operations – net of tax	**—**	—	—
Income before accounting change	**60**	70	88
Cumulative effect of accounting change – net of tax	**—**	—	—
Net income	**$ 60**	$ 70	$ 88

Contract Buyout / Termination and Other

In March 2008, First Energy exercised an early buyout right under the terms of an existing lease agreement with Edison Capital related to Unit No. 2 of the Beaver Valley Nuclear Power Plant. The termination date of the lease under the early buyout option was June 1, 2008. Proceeds from the sale were $72 million. Edison Capital recorded a pre-tax gain of $41 million ($23 million after tax) during the second quarter of 2008. The 2008 increase also reflects approximately $7 million in gains on the sale of investments at Edison Capital.

Equity in Income from Partnerships and Unconsolidated Subsidiaries – Net

Equity in income from partnerships and unconsolidated subsidiaries – net decreased in 2008 mainly due to gains from Edison Capital's global infrastructure funds recorded in 2007.

Other Nonoperating Income

In 2006, Edison Capital recorded a $19 million pre-tax gain on the sale of certain investments, including Edison Capital's interest in an affordable housing project.

Income Tax Expense

The composite federal and state statutory income tax rate was approximately 40% (net of federal benefit of state income taxes) for all periods presented. The lower effective tax rates of 32.6%, (2.9)%, and 9.3% realized in 2008, 2007 and 2006 respectively, as compared to the statutory rate, were primarily due to low-income housing tax credits.

Historical Cash Flow Analysis

The "Historical Cash Flow Analysis" section of this MD&A discusses consolidated cash flows from operating, financing and investing activities.

Cash Flows from Operating Activities

Net cash provided by operating activities is as follows:

In millions **For The Year Ended December 31,**	**2008**	**2007**	**2006**
Continuing operations	**$ 2,210**	$ 3,195	$ 3,474
Discontinued operations	**—**	(2)	94
	$ 2,210	$ 3,193	$ 3,568

Cash provided by operating activities from continuing operations decreased $985 million in 2008, compared to 2007. The 2008 change was mainly due to a net $300 million increase in balancing account undercollections, mainly related to a $750 million increase in ERRA undercollections, partially offset by $200 million in refund payments received related to SCE's public purpose programs, $100 million refunded to ratepayers as a result of SCE's PBR decision, and a net $150 million in other balancing account overcollections. The change was also due to a $240 million decrease related to the elimination of amounts collected in 2008 for the repayment of SCE rate reduction bonds. These bonds were fully repaid in December 2007. The bond payment is reflected in financing activities. The decrease was partially offset by margin deposits received from counterparties at December 31, 2008. The 2008 change was also due to the timing of cash receipts and disbursements related to working capital items.

Cash provided by operating activities from continuing operations decreased $279 million in 2007 compared to 2006. The 2007 change reflects an increase of $48 million in required margin and collateral deposits in 2007 for EMG's hedging and trading activities, compared to a decrease of $625 million in 2006. This change resulted from an increase in forward market prices in 2007 compared to 2006. The 2007 change also reflects a decrease in revenue collected from SCE's customers primarily due to lower rates in 2007 compared to 2006. On February 14, 2007, SCE reduced its system average rate mainly as the result of estimated lower natural gas prices in 2007, the refund of overcollections in the ERRA balancing account that occurred in 2006 and the impact of the redesign of SCE's tiered rate structure in 2007. The 2007 change was also due to the timing of cash receipts and disbursements related to working capital items including lower income taxes paid in 2007 compared to 2006.

Cash provided by operating activities from discontinued operations decreased in 2007 from 2006 reflecting higher distributions received in 2006 compared to 2007 from the Lakeland power project. See "Discontinued Operations" for more information regarding these distributions.

Cash Flows from Financing Activities

Net cash provided (used) by financing activities is as follows:

In millions **For The Year Ended December 31,**	**2008**	**2007**	**2006**
Continuing operations	**$ 3,210**	$ (877)	$ (703)

Cash provided (used) by financing activities from continuing operations mainly consisted of long-term debt issuances (payments) at SCE and EMG and dividends paid by Edison International to its common shareholders.

Financing activities in 2008 were as follows:

- In January, SCE issued $600 million of first refunding mortgage bonds due in 2038. The proceeds were used to repay SCE's outstanding commercial paper of approximately $426 million and for general corporate purposes.
- During the first quarter, SCE purchased $212 million of its auction rate bonds, converted the issue to a variable rate structure, and terminated the FGIC insurance policy. SCE continues to hold the bonds which remain outstanding and have not been retired or cancelled.
- In January, SCE repurchased 350,000 shares of 4.08% cumulative preferred stock at a price of $19.50 per share. SCE retired this preferred stock in January 2008 and recorded a $2 million gain on the cancellation of reacquired capital stock (reflected in the caption "Common stock" on the consolidated balance sheets).
- In August, SCE issued $400 million of 5.50% first and refunding mortgage bonds due in 2018. The proceeds were used to repay SCE's outstanding commercial paper of approximately $110 million and borrowings under the credit facility of $200 million, as well as for general corporate purposes.
- In October, SCE issued $500 million of 5.75% first and refunding mortgage bonds due in 2014. The proceeds were used for general corporate purposes.
- During 2008, SCE's net issuances of short-term debt were $1.4 billion.
- During 2008, EME borrowed $851 million under its credit agreements.
- During 2008, Edison International's (parent) net issuances of short-term debt were $250 million.
- Other financing activities in 2008 include dividend payments of $397 million paid by Edison International to its common shareholders and payments of $66 million for the purchase and delivery of outstanding common stock for settlement of stock based awards (facilitated by a third party).

Financing activities in 2007 were as follows:

- In May 2007, EME issued $2.7 billion of senior notes, the proceeds of which were mostly used to repay $587 million of EME's outstanding senior notes, repay $1 billion of Midwest Generation's second priority senior secured notes, fund a dividend to MEHC which purchased approximately $796 million of its 13.5% senior secured notes, and repay $328 million of Midwest Generation's senior secured term loan facility. In addition, EME and MEHC paid tender premiums and financing costs of $239 million related to the debt refinancing.
- During 2007, SCE's net issuance of short-term debt was $500 million.
- During the fourth quarter of 2007, SCE repaid the remaining outstanding balance of its rate reduction bonds in the amount of $246 million.

- Other financing activities in 2007 include dividend payments of $378 million paid by Edison International to its common shareholders and payments of $215 million for the purchase and delivery of outstanding common stock for settlement of stock based awards (facilitated by a third party).

Financing activities in 2006 included activities related to the rebalancing of SCE's capital structure and rate base growth and the reduction of debt at EMG, as follows:

- In January 2006, SCE issued $500 million of first and refunding mortgage bonds which consisted of $350 million of 5.625% bonds due in 2036 and $150 million of floating rate bonds due in 2009. The proceeds from this issuance were used in part to redeem $150 million of variable rate first and refunding mortgage bonds due in January 2006 and $200 million of its 6.375% first and refunding mortgage bonds due in January 2006.
- In January 2006, SCE issued 2,000,000 shares of 6% Series C preference stock (noncumulative, $100 liquidation value) and received net proceeds of approximately $197 million.
- In April 2006, SCE issued $331 million of tax-exempt bonds which consisted of $196 million of 4.10% bonds which are subject to remarketing in April 2013 and $135 million of 4.25% bonds which are subject to remarketing in November 2016. The proceeds from this issuance were used to call and redeem $196 million of tax-exempt bonds due February 2008 and $135 million of tax-exempt bonds due March 2008. This transaction was treated as a noncash financing activity.
- In June 2006, EME issued $1 billion of senior notes. The proceeds from this issuance were mostly used to repay $1 billion of EME's outstanding senior notes and to pay $139 million for tender premiums and related fees.
- In December 2006, SCE issued $400 million of 5.55% first and refunding mortgage bonds due in 2037. The proceeds from this issuance were used for general corporate purposes.
- During 2006, Midwest Generation had net repayments of $170 million under its credit facility.
- Other financing activities in 2006 include dividend payments of $352 million paid by Edison International to its common shareholders and payments of $173 million for the purchase and delivery of outstanding common stock for settlement of stock based awards (facilitated by a third party).

Cash Flows from Investing Activities

Net cash used by investing activities is as follows:

In millions	For The Year Ended December 31,	2008	2007	2006
Continuing operations		**$ (2,945)**	$ (2,670)	$ (2,963)

Cash flows from investing activities are affected by capital expenditures, SCE's funding of nuclear decommissioning trusts, and proceeds and maturities of investments.

Investing activities in 2008 reflect $2.3 billion in capital expenditures at SCE, primarily for transmission and distribution assets, including approximately $99 million for nuclear fuel acquisitions, and $556 million in capital expenditures at EMG primarily due to expansion of investments for renewable energy projects. Investing activities include investments in other assets at EMG of $213 million, related to turbine deposits for wind projects prior to commencement of construction. Investing activities also include net maturities and sales of short-term investments of $74 million and net purchases of nuclear decommissioning trust investments and other of $7 million, and proceeds of $28 million from the sale of 33% of EME's membership in the Elkhorn Ridge wind project during the second quarter of 2008.

Investing activities in 2007 reflect $2.3 billion in capital expenditures at SCE, primarily for transmission and distribution assets, including approximately $123 million for nuclear fuel acquisitions, and $540 million in capital expenditures at EMG. Investing activities include investments in other assets at EMG of $271 million related to turbine deposits for wind projects prior to commencement of construction. Investing activities also include net maturities and sales of short term investments of $477 million, net purchases of nuclear decommissioning trust investments and other of $133 million, payments of $22 million towards the purchase price of new wind projects, payment of $24 million during 2007 to acquire a 1% interest in twelve designated projects and the option to purchase the remaining 99% interest, and $11 million in payments made toward the purchase price of EMG's Wildorado wind project during the second quarter of 2007.

Investing activities in 2006 reflect $2.2 billion in capital expenditures at SCE, primarily for transmission and distribution assets, including approximately $81 million for nuclear fuel acquisitions and $13 million related to the Mountainview plant, and $310 million in capital expenditures at EMG. Investing activities include investments in other assets at EMG, of $130 million related to turbine deposits for wind projects prior to commencement of construction. Investing activities also include net purchases of marketable securities of $375 million at EMG, net purchases of nuclear decommissioning trust investments and other of $140 million, as well as the receipt of $43 million in proceeds from the sale of 25% of EME's ownership interest in the San Juan Mesa wind project. EMG also paid $18 million towards the purchase price of the Wildorado wind project during the first quarter of 2006.

DISCONTINUED OPERATIONS

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) in 2005. EME was entitled to receive the remaining amount of the settlement after payment of creditor claims. As creditor claims were settled, EME received payments of £0.4 million (approximately $1 million) in 2008, £5 million (approximately $10 million) in 2007, and £72 million (approximately $125 million) in 2006. The after-tax income attributable to the Lakeland project was $1 million, $6 million and $85 million for 2008, 2007 and 2006, respectively. Beginning in 2002, EME reported the Lakeland project as discontinued operations and accounted for its ownership of Lakeland Power on the cost method (earnings are recognized as cash is distributed from the project).

For all years presented, the results of EME's international projects, discussed above, have been accounted for as discontinued operations on the consolidated financial statements in accordance with SFAS No. 144.

There was no revenue from discontinued operations in 2008, 2007 or 2006. The pre-tax earnings from discontinued operations were $6 million in 2008, $3 million in 2007 and $118 million in 2006.

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 right of first refusal resulted in a $3 million additional loss recorded in 2006.

There were no assets or liabilities of discontinued operations at December 31, 2008 and 2007.

ACQUISITIONS AND DISPOSITIONS

Acquisitions

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. This project started construction in April 2006 and commenced commercial operation during April 2007. 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 on Edison International's consolidated balance sheet.

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.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

The accounting policies described below are viewed by management as critical because their application is the most relevant and material to Edison International's results of operations and financial position and these policies require the use of material judgments and estimates.

Rate Regulated Enterprises

SCE applies SFAS No. 71 to the portion of its operations in which regulators set rates at levels intended to recover the estimated costs of providing service, plus a return on its net investment, or rate base. Regulators also may impose certain penalties or grant certain incentives. Due to timing and other differences in the collection of revenue, these principles allow an incurred cost that would otherwise be charged to expense by a nonregulated entity to be capitalized as a regulatory asset if it is probable that the cost is recoverable through future rates; conversely the principles allow creation of a regulatory liability for probable future costs collected through rates in advance. SCE's management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as the current regulatory environment, the issuance of rate orders on recovery of the specific incurred cost or a similar incurred cost to SCE or other rate-regulated entities in California, and assurances from the regulator (as well as its primary intervenor groups) that the incurred cost will be treated as an allowable cost for rate-making purposes. Because current rates include the recovery of existing regulatory assets and settlement of regulatory liabilities, and rates in effect are expected to allow SCE to earn a reasonable rate of return, management believes that existing regulatory assets and liabilities are probable of recovery. This determination reflects the current political and regulatory climate in California and is subject to change in the future. If future recovery of costs ceases to be probable, all or part of the regulatory assets and liabilities would have to be written off against current period earnings. At December 31, 2008, the consolidated balance sheets included regulatory assets of $6.0 billion and regulatory liabilities of $3.6 billion. Management continually evaluates the anticipated recovery of regulatory assets, incentives and revenue subject to refund, as well as the anticipated cost of regulatory liabilities or penalties and provides for allowances and/or reserves as appropriate.

Derivative Financial Instruments and Hedging Activities

Edison International 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 remaining gain or loss on the derivative instrument, if any, is recognized currently in earnings. SCE fair value changes are expected to be recovered from or refunded to ratepayers, and therefore SCE's fair value changes have no impact on earnings, but may temporarily affect cash flows.

Derivative assets and liabilities are shown at gross amounts on the consolidated balance sheets, except that net presentation is used when Edison International has the legal right of offset, such as multiple contracts executed with the same counterparty under master netting arrangements. The results of derivative activities are recorded as part of cash flows from operating activities in the consolidated statements of cash flows. 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.

Determining whether or not Edison International's transactions meet the definition of a derivative instrument requires management to exercise significant judgment, including determining whether the transaction has one or more underlyings, one or more notional amounts, requires no initial net investment, and whether the terms require or permit net settlement. If it is determined that the transaction meets the definition of a derivative instrument, additional management judgment is exercised in determining whether the normal sales and purchases exception applies or whether individual transactions qualify for hedge accounting treatment, if elected.

Most of SCE's QF contracts are not required to be recorded on its balance sheet because they either do not meet the definition of a derivative or meet the normal purchases and sales exception. However, SCE purchases power from certain QFs in which the contract pricing is based on a natural gas index, but the power is not generated with natural gas. The portion of these contracts that is not eligible for the normal purchases and sales exception under accounting rules is recorded on the balance sheet at fair value, based on financial models. Unit-specific contracts (signed or modified after June 30, 2003) in which SCE takes virtually all of the output of a facility are generally considered to be leases under EITF No. 01-8.

EME uses derivative financial instruments for hedging activities and trading purposes. Derivative financial instruments are mainly utilized by EME to manage exposure from changes in electricity and fuel prices, and interest rates. 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, 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 nonutility power generation revenue in the accompanying consolidated statements of income 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."

For those transactions that are accounted for as derivative instruments, determining the fair value requires management to exercise significant judgment. Edison International makes estimates and assumptions concerning future commodity prices, load requirements and interest rates in determining the fair value of a derivative instrument. The fair value of a derivative is susceptible to significant change resulting from a number of factors, including volatility of commodity prices, credit risks, market liquidity and discount rates. See "SCE: Market Risk Exposures" and "EMG: Market Risk Exposures" for a description of risk management activities and sensitivities to change in market prices.

Fair Value Accounting

Edison International follows SFAS No. 157 which established a framework for measuring fair value. SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants as of the measurement date (referred to as an "exit price" in SFAS No. 157). Edison International's assets and liabilities carried at fair value primarily consist of derivative contracts, nuclear decommissioning trust investments, pension and postretirement benefits other than pension, and money market funds. Derivative contracts primarily relate to power and gas and include contracts for forward physical sales and purchases, options and forward price swaps which settle only on a financial basis (including futures contracts). Derivative contracts can be exchange traded, over-the-counter traded, or structured transactions.

Edison International makes estimates and significant judgments in order to determine the fair value of an instrument including those related to quoted market prices, time value of money, volatility of the underlying commodities, non-performance risks of counterparties and other factors. If quoted market prices are not available, SCE uses internally maintained standardized or industry accepted models to determine the fair value. The models are updated with spot prices, forward prices, volatilities and interest rates from regularly published and widely distributed independent sources. Under SFAS No. 157, when actual market prices, or relevant observable inputs are not available, it is appropriate to use unobservable inputs which reflect management assumptions, including extrapolating limited short-term observable data and developing correlations between liquid and non-liquid trading hubs. In assessing non-performance risks, EME reviews credit ratings of counterparties (and related default rates based on such credit ratings) and prices of credit default swaps. The market price (or premium) for credit default swaps represents the price that a counterparty would pay to transfer the risk of default, typically bankruptcy, to another party. A credit default swap is not directly comparable to the credit risks of derivative contracts, but provides market information of the related risk of non-performance.

In addition, SFAS No. 157 established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets and liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements) (see "Edison International Notes to Consolidated Financial Statements — Note 10. Fair Value Measurements" for further information).

Level 3 includes the majority of SCE's derivatives, including over-the-counter options, bilateral contracts, capacity contracts, and QF contracts. The fair value of these SCE derivatives is determined using uncorroborated non-binding broker quotes (from one or more brokers) and models which may require SCE to extrapolate short-term observable inputs in order to calculate fair value. Broker quotes are obtained from several brokers and compared against each other for reasonableness. SCE has Level 3 fixed float swaps for which SCE obtains the applicable Henry Hub and basis forward market prices from the New York Mercantile Exchange. However, these swaps have contract terms that extend beyond observable market data and the unobservable inputs incorporated in the fair value determination are considered significant compared to the overall swap's fair value.

Level 3 also includes derivatives that trade infrequently (such as financial transmission rights, FTRs and CRRs in the California market and over-the-counter derivatives at illiquid locations), derivatives with counterparties that have significant non-performance risks and long-term power agreements. For illiquid financial transmission rights, FTRs and CRRs, Edison International reviews objective criteria related to system congestion and other underlying drivers and adjusts fair value when Edison International concludes a change in objective criteria would result in a new valuation that better reflects the fair value. Recent auction prices are used to determine the fair value of short-term CRRs. Edison International recorded liquidity reserves against the long-term CRRs fair values since there were no quoted long-term market prices for the CRRs and insufficient evidence of long-term market prices.

Changes in fair values are based on the hypothetical sale of illiquid positions. For illiquid long-term power agreements, fair value is based upon a discounting of future electricity and natural gas prices derived from a proprietary model using the risk free discount rate for a similar duration contract, adjusted for credit risk and market liquidity. Changes in fair value are based on changes to forward market prices, including forecasted prices for illiquid forward periods. In circumstances where Edison International cannot verify fair value with observable market transactions, it is possible that a different valuation model could produce a materially different estimate of fair value. As markets continue to develop and more pricing information becomes available, Edison International continues to assess valuation methodologies used to determine fair value.

The amount of Edison International's Level 3 derivative assets and liabilities measured using significant unobservable inputs as a percentage of the total derivative assets and total derivative liabilities (excluding netting and collateral) measured at fair value were 51% and 65%, respectively.

SCE's investment policies and CPUC requirements place limitations on the types and investment grade ratings of the securities that may be held by the nuclear decommissioning trust funds. These policies restrict the trust funds from holding alternative investments and limit the trust funds' exposures to investments in highly illiquid markets. With respect to equity securities, the trustee obtains prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which SCE is able to independently corroborate. Regarding fixed income securities, the trustee receives multiple prices from pricing services, which enable cross-provider validations by the trustee in addition to unusual daily movement checks. A primary price source is identified based on asset type, class or issue for each security. The trustee monitors prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the trustee challenges an assigned price and determines that another price source is considered to be preferable. Additionally, SCE corroborates the fair values of securities by comparison to other market-based price sources obtained by SCE's investment managers. The trustee validation procedures for pension and PBOP assets are the same as the nuclear decommissioning trusts. Level 3 includes prices or valuations that require inputs that are both significant to the fair value measurements and unobservable.

Management uses significant judgment and assumptions in order to determine the fair value of Level 3 transactions. Due to its regulatory treatment, SCE's fair value transactions discussed above are recovered in rates. EME's fair value transactions discussed above could have a material impact on financial results.

Income Taxes

Edison International's eligible subsidiaries are included in Edison International's consolidated federal income tax and combined state tax returns. Edison International has tax-allocation and payment agreements with certain of its subsidiaries. For subsidiaries other than SCE, the right of a participating subsidiary to receive or make a payment and the amount and timing of tax-allocation payments are dependent on the inclusion of the subsidiary in the consolidated income tax returns of Edison International and other factors including the consolidated taxable income of Edison International and its includible subsidiaries, the amount of taxable income or net operating losses and other tax items of the participating subsidiary, as well as the other subsidiaries of Edison International. There are specific procedures regarding allocations of state taxes. Each subsidiary is eligible to receive tax-allocation payments for its tax losses or credits only at such time as Edison International and its subsidiaries generate sufficient taxable income to be able to utilize the participating subsidiary's losses in the consolidated income tax return of Edison International. Under an income tax-allocation agreement approved by the CPUC, SCE's tax liability is computed as if it filed its federal and state income tax returns on a separate return basis.

Edison International applies the asset and liability method of accounting for deferred income taxes as required by SFAS No. 109, "Accounting for Income Taxes." In accordance with FIN 48, "Accounting for Uncertainty in Income Taxes," Edison International applies judgment to assess each tax position taken on filed tax returns and tax positions expected to be taken on future returns to determine whether a tax position is more likely than not to be sustained and recognized in the financial statements. However, all temporary tax positions, whether or not the more likely than not threshold of FIN 48 is met, are recorded in the financial statements in accordance with the measurement principles of FIN 48.

As part of the process of preparing its consolidated financial statements, Edison International 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 Edison International's consolidated balance sheet. Edison International takes certain tax positions it believes are applied in accordance with tax laws. The application of these positions is subject to interpretation and audit by the IRS. As further described in "Other Developments — Federal and State Income Taxes," the IRS has raised issues in the audit of Edison International's tax returns with respect to certain leveraged leases of Edison Capital.

Investment tax credits associated with rate-regulated public utility property are deferred and amortized over the lives of the properties and production tax credits are recognized in the period in which they are earned.

Accounting for tax obligations requires judgments, including estimating reserves for potential adverse outcomes regarding tax positions that have been taken. Management uses judgment in determining whether the evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained on audit. Management continually evaluates its income tax exposures and provides for allowances and/or reserves as appropriate, reflected in the captions "Accrued taxes" and "Other deferred credits and long-term liabilities" on the consolidated balance sheets. Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Interest expense and penalties associated with income taxes are reflected in the caption "Income tax expense" on the consolidated statements of income.

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 "Off-Balance Sheet Transactions"). 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. 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 sheets. 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 recognition of 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 "Off-Balance Sheet Transactions."

Edison Capital has entered into lease transactions, as lessor, related to various power generation, electric transmission and distribution, transportation and telecommunications assets. All of the debt under Edison Capital's leveraged leases is nonrecourse and is not recorded on Edison International's balance sheets in accordance with SFAS No. 13, "Accounting for Leases."

Partnership investments, in which Edison International owns a percentage interest and does not have operational control or significant voting rights, are accounted for under the equity method as required by Accounting Principles Board Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock." As such, the project assets and liabilities are not consolidated on the balance sheets. Rather, the financial statements reflect only the proportionate ownership share of net income or loss. See "Off-Balance Sheet Transactions."

Asset Impairment

Edison International evaluates the impairment of its investments in projects and other long-lived assets based on a review of estimated cash flows expected to be generated whenever events or changes in circumstances indicate 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 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. In accordance with SFAS No. 71, SCE's impaired assets are recorded as a regulatory asset if it is deemed probable that such amounts will be recovered from the ratepayers.

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 Edison International 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. The expected future undiscounted cash flow from EME's assets or group of assets is a critical accounting policy because: (1) estimates of future prices of energy and capacity in wholesale energy markets and fuel prices are susceptible to significant change, (2) uncertainties exist regarding the impact of existing and future environmental regulations, (3) the period of the forecast is over an extended period of time due to the length of the estimated remaining useful lives, and (4) the impact of an impairment on EME's consolidated financial position and results of operations would be material.

Midwest Generation has regulatory requirements in Illinois to reduce SO_2 and NO_x emissions to target rates and to install specific environmental control equipment by specific dates for each coal unit (except Unit 6 at Joliet Station) or it would be required to shut down the specified coal unit. See "Other Developments — Environmental Matters" for further discussion regarding the CPS. No decision has been made to make such capital improvements. The decision to make capital improvements is dependent on a number of factors affecting the economic analysis and potential impact of further environmental regulations. If EME were to decide not to install additional environmental control equipment and, instead, shut down an entire plant by the date required, the remaining estimated useful life of the plant would be shortened (thereby increasing the annual depreciation expense). The change in estimated useful life could trigger an impairment. If the undiscounted expected cash flow measured at a plant level were less than the net book value of the asset group, an impairment would be recognized. EME includes allocated acquired emission allowances as part of the asset group under SFAS No. 144. In the case of the Powerton and Joliet Stations, EME also includes prepaid rent in the asset group. EME's unit of account is at the plant level and, accordingly, the closure of a unit at a multi-unit site would not result in an impairment of property, plant and equipment unless such condition were to affect an impairment assessment on the entire plant.

Nuclear Decommissioning

Edison International's legal AROs related to the decommissioning of SCE's nuclear power facilities are recorded at fair value. The fair value of decommissioning SCE's nuclear power facilities is based on site-specific studies performed in 2005 for SCE's San Onofre and Palo Verde nuclear facilities. Changes in the estimated costs or timing of decommissioning, or the assumptions underlying these estimates are based on management judgments and could cause material revisions to the estimated total cost to decommission these facilities. SCE estimates that it will spend approximately $11.5 billion through 2049 to decommission its active nuclear facilities. This estimate is based on SCE's decommissioning cost methodology used for rate-making purposes, escalated at rates ranging from 1.7% to 7.5% (depending on the cost element) annually.

Nuclear decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately $46 million per year. As of December 31, 2008, the decommissioning trust balance was $2.5 billion. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. The next filing is in April 2009 for contribution changes in 2011. The contributions are determined based on an analysis of the current value of trust assets and long-term forecasts of cost escalation, the estimate and timing of decommissioning costs, and after-tax return on trust investments. Favorable or unfavorable investment performance in a period will not change the amount of contributions for that period. However, trust performance for the three years leading up to a CPUC review proceeding will provide input into future contributions. The CPUC has set certain restrictions related to the investments of these trusts. If additional funds are needed for decommissioning, it is probable that the additional funds will be recoverable through customer rates. Trust funds are recorded on the balance sheet at fair market value.

SCE's nuclear decommissioning trusts are accounted for in accordance with SFAS No. 115 and due to regulatory recovery of SCE's nuclear decommissioning expense, rate-making accounting treatment is applied to all nuclear decommissioning trust activities in accordance with SFAS No. 71. As a result, nuclear decommissioning activities do not affect SCE's earnings.

SCE's nuclear decommissioning trust investments are classified as available-for-sale. SCE has debt and equity investments for the nuclear decommissioning trust funds. Due to regulatory mechanisms, earnings and realized gains and losses (including other-than-temporary impairments) have no impact on electric utility revenue. Unrealized gains and losses on decommissioning trust funds increase or decrease the trust assets and the related regulatory asset or liability and have no impact on electric utility revenue or decommissioning expense. SCE reviews each security for other-than-temporary impairment losses on the last day of each month compared to the last day of the previous month. If the fair value on both days is less than the cost for that security, SCE will recognize a realized loss for the other-than-temporary impairment. If the fair value is greater or less than the cost for that security at the time of sale, SCE will recognize a related realized gain or loss, respectively.

Decommissioning of San Onofre Unit 1 is underway. All of SCE's San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds, subject to CPUC review. The estimated remaining cost to decommission San Onofre Unit 1 of $59 million as of December 31, 2008 is recorded as an ARO liability.

Pensions and Postretirement Benefits Other than Pensions

SFAS No. 158 requires companies to recognize the overfunded or underfunded status of defined benefit pension and other postretirement plans as assets and liabilities in the balance sheet; the assets and/or liabilities are normally offset through other comprehensive income (loss). Edison International adopted SFAS No. 158 as of December 31, 2006. In accordance with SFAS No. 71, Edison International recorded regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for its postretirement benefit plans that are recoverable in utility rates. SFAS No. 158 also requires companies to align the measurement dates for their plans to their fiscal year-ends. Edison International already has a fiscal year-end measurement date for all of its postretirement plans.

Pension and other postretirement obligations and the related effects on results of operations are calculated using actuarial models. Two critical assumptions, discount rate and expected return on assets, are important elements of plan expense and liability measurement. Additionally, health care cost trend rates are critical assumptions for postretirement health care plans. These critical assumptions are evaluated at least annually. Other assumptions, which require management judgment, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

The discount rate enables Edison International to state expected future cash flows at a present value on the measurement date. Edison International 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. Two corporate yield curves were considered, Citigroup and AON. At the December 31, 2008 measurement date, Edison International used a discount rate of 6.25% for both pensions and PBOPs.

To determine the expected long-term rate of return on pension plan assets, current and expected asset allocations are considered, as well as historical and expected returns on plan assets. The expected rate of return on plan assets was 7.5% for pensions and 7.0% for PBOP. A portion of PBOP trusts asset returns are subject to taxation, so the 7.0% rate of return on plan assets above is determined on an after-tax basis. Actual time-weighted, annualized returns (losses) on the pension plan assets were (31.0)%, 1.5% and 4.1% for the one-year, five-year and ten-year periods ended December 31, 2008, respectively. Actual time-weighted, annualized returns (losses) on the PBOP plan assets were (31.1)%, (0.2)%, and 1.0% over these same periods. Accounting principles provide that differences between expected and actual returns are recognized over the average future service of employees.

SCE accounts for about 92% of Edison International's total pension obligation, and 96% of its assets held in trusts, at December 31, 2008. SCE records pension expense equal to the amount funded to the trusts, as calculated using an actuarial method required for rate-making purposes, in which the impact of market volatility on plan assets is recognized in earnings on a more gradual basis. Any difference between pension expense calculated in accordance with rate-making methods and pension expense calculated in accordance with SFAS No. 87, "Employers' Accounting for Pensions," and SFAS No. 158 is accumulated as a regulatory asset or liability, and will, over time, be recovered from or returned to customers. As of December 31, 2008, this cumulative difference amounted to a regulatory liability of $71 million, meaning that the rate-making method has recognized $71 million more in expense than the accounting method since implementation of SFAS No. 87 in 1987.

Edison International's pension and PBOP plans are subject to limits established for federal tax deductibility. SCE funds its pension and PBOP plans in accordance with amounts allowed by the CPUC. Executive pension plans and nonutility PBOP plans have no plan assets.

At December 31, 2008, Edison International's PBOP plans had a $2.4 billion benefit obligation. Total expense for these plans was $39 million for 2008. The health care cost trend rate is 9.25% for 2008, gradually declining to 5.0% for 2015 and beyond. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2008 by $263 million and annual aggregate service and interest costs by $18 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2008 by $236 million and annual aggregate service and interest costs by $16 million.

Accounting for Contingencies

In accordance with SFAS No. 5, "Accounting for Contingencies," Edison International records loss contingencies when it determines that the outcome of future events is probable of occurring and when the amount of the loss can be reasonably estimated. These reserves are based on management judgment and estimates taking into consideration available information and are adjusted when events or circumstances cause these judgments or estimates to change. Edison International provides disclosure for contingencies when there is a reasonable possibility that a loss or an additional loss may be incurred. Gain contingencies are recognized in the financial statements when they are realized. Actual amounts realized upon settlement of contingencies may be different than amounts recorded and disclosed and could have a significant impact on the liabilities, revenue and expenses recorded in the financial statements. See "SCE: Regulatory Matters" and "Other Developments" for a discussion of contingencies and regulatory issues.

NEW ACCOUNTING PRONOUNCEMENTS

New accounting pronouncements are discussed in Note 1 — Summary of Significant Accounting Policies — New Accounting Pronouncements under "Edison International's Notes to Consolidated Financial Statements."

COMMITMENTS, GUARANTEES AND INDEMNITIES

Edison International's commitments as of December 31, 2008, for the years 2009 through 2013 and thereafter are estimated below:

In millions	2009	2010	2011	2012	2013	Thereafter
Long-term debt maturities and interest[(1)]	$ 824	$ 930	$ 641	$ 1,479	$ 1,095	$ 15,368
Fuel supply contract payments	667	278	173	202	192	725
Gas and coal transportation payments	245	169	8	8	8	35
Purchased-power capacity payments	289	368	519	681	660	4,308
Operating lease obligations	1,051	1,023	832	718	701	4,161
Capital lease obligations	4	12	17	19	19	1,153
Turbine commitments	706	232	—	—	—	—
Capital improvements	150	—	—	—	—	—
Other commitments	67	85	74	63	33	24
Employee benefit plans contributions[(2)]	179	—	—	—	—	—
Total[(3)]	**$ 4,182**	**$ 3,097**	**$ 2,264**	**$ 3,170**	**$ 2,708**	**$ 25,774**

(1) Amount includes scheduled principal payments for debt outstanding as of December 31, 2008 and related forecast interest payments over the applicable period of the debt.

(2) Amount includes estimated contributions to the pension and PBOP plans. The estimated contributions for SCE and EME are not available beyond 2009.

(3) At December 31, 2008, Edison International had a total net liability recorded for uncertain tax positions of $450 million, which is excluded from the table. Edison International cannot make reliable estimates of the cash flows by period due to uncertainty surrounding the timing of resolving these open tax issues with the IRS.

Fuel Supply Contracts

SCE has fuel supply contracts which require payment only if the fuel is made available for purchase. SCE has a coal fuel contract that requires payment of certain fixed charges whether or not coal is delivered.

At December 31, 2008, Midwest Generation and EME Homer City had fuel purchase commitments with various third-party suppliers. The minimum commitments are based on the contract provisions, which consist of fixed prices, subject to adjustment clauses. In connection with the acquisition of the Illinois Plants, Midwest Generation had assumed a long-term coal supply contract and recorded a liability to reflect the fair value of this contract. In March 2008, Midwest Generation entered into an agreement to buy out its coal obligations for the years 2009 through 2012 under this contract with a one-time payment to be made in January 2009.

Gas and Coal Transportation

At December 31, 2008, 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 nine years.

At December 31, 2008, Midwest Generation had contractual commitments for the transport of coal to their respective facilities. 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 its fuel supply contracts.

Power-Purchase Contracts

SCE has power-purchase contracts with certain QFs (cogenerators and small power producers) and other power producers. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE (the energy payments are not included in the table above). There are no requirements to make debt-service payments. In an effort to replace higher-cost contract payments with lower-cost replacement power, SCE has entered into power-purchase settlements to end its contract obligations with certain QFs. The settlements are reported as power-purchase contracts on the consolidated balance sheets.

Operating and Capital Leases

In accordance with EITF No. 01-8, power contracts signed or modified after June 30, 2003, need to be assessed for lease accounting requirements. Unit specific contracts in which SCE takes virtually all of the output of a facility are generally considered to be leases. As of December 31, 2005, SCE had six power contracts classified as operating leases. In 2006, SCE modified 62 power contracts. No contracts were modified in 2007 and 2008. The modifications to the contracts resulted in a change to the contractual terms of the contracts at which time SCE reassessed these power contracts under EITF No. 01-8 and determined that the contracts are leases and subsequently met the requirements for operating leases under SFAS No. 13. These power contracts had previously been grandfathered relative to EITF No. 01-8 and did not meet the normal purchases and sales exception. As a result, these contracts were recorded on the consolidated balance sheets at fair value in accordance with SFAS No. 133. Due to regulatory mechanisms, fair value changes did not affect earnings. At the time of modification, SCE had assets and liabilities related to mark-to-market gains or losses. Under SFAS No. 133, the assets and liabilities were reclassified to a lease prepayment or accrual and were included in the cost basis of the lease. The lease prepayment and accruals are being amortized over the life of the lease on a straight-line basis. At December 31, 2008, the net liability was $64 million. At December 31, 2008, SCE had 69 power contracts classified as operating leases. Operating lease expense for power purchases was $328 million in 2008, $297 million in 2007, and $188 million in 2006. In addition, as of December 31, 2008, SCE had four power purchase contracts which met the requirements for capital leases. These capital leases have a net commitment of $1.22 billion at December 31, 2008 and $20 million at December 31, 2007. SCE's total estimated capital lease executory costs and interest expense were $1.71 billion at December 31, 2008 and $20 million at December 31, 2007.

At December 31, 2008, 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 Units 7 and 8 of the 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 2009, $325 million in 2010, $311 million in 2011, $311 million in 2012, $300 million in 2013, and the minimum lease payments due after 2013 are $2.0 billion. For further discussion, see "— Off-Balance Sheet Transactions — Sale-Leaseback Transactions."

Edison International has other operating leases for office space, vehicles, property and other equipment (with varying terms, provisions and expiration dates).

Turbine Commitments

EME had entered into various turbine supply agreements with vendors to support its wind development efforts. At December 31, 2008, EME had secured 484 wind turbines (942 MW) for use in future projects for an aggregate purchase price of $1.2 billion. One of EME's turbine suppliers has requested an escalation adjustment to its pricing for 2008 and 2009 turbines pursuant to its turbine supply agreement. EME is evaluating the request, and discussions with the supplier are ongoing. Under certain of these agreements, EME may terminate the purchase of individual turbines, or groups of turbines, for convenience. Upon any such termination, EME may be obligated to pay termination charges to the vendor.

For a discussion on wind turbine performance issues, see "Results of Operations and Historical Cash Flow Analysis — Nonutility Power Generation Net Income — Renewable Energy Projects" and "EMG: Market Risk Exposures — Credit Risk."

Capital Improvements

At December 31, 2008, EME's subsidiaries had firm commitments in 2009 for capital and construction expenditures. The majority of these expenditures primarily relate to the construction of wind projects and environmental improvements at the Illinois Plants. These expenditures are planned to be financed by cash on hand and cash generated from operations.

Other Commitments

SCE has an unconditional purchase obligation for firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the transmission service provider, whether or not the transmission line is operable. The contract requires minimum payments of $60 million through 2016 (approximately $7 million per year).

At December 31, 2008, EME and its subsidiaries were party to a long-term power purchase contract, a coal cleaning agreement, turbine operations and maintenance agreements, and agreements for the purchase of limestone, ammonia, and materials for environmental controls equipment.

As of December 31, 2008, standby letters of credit aggregated $133 million and were scheduled to expire in 2009.

Guarantees and Indemnities

Edison International's subsidiaries have various financial and performance guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts included performance guarantees, guarantees of debt and indemnifications.

Tax Indemnity Agreements

In connection with the sale-leaseback transactions related to the Homer City facilities in Pennsylvania, the Powerton and Joliet Stations in Illinois and, previously, the Collins Station in Illinois, EME and several of its subsidiaries entered into tax indemnity agreements. Although the Collins Station lease terminated in April 2004, Midwest Generation's tax indemnity agreement with the former lease equity investor is still in effect. 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.

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 takes 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. Commonwealth Edison has advised EME that Commonwealth Edison believes it is entitled to indemnification for all liabilities, costs, and expenses that it may be required to bear as a result of the NOV discussed under "EMG: Other Developments — Midwest Generation New Source Review Notice of Violation" and potential litigation by private groups related to the NOV. 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 had an initial five-year term with an automatic renewal provision for subsequent one-year terms (subject to the right of either party to terminate); pursuant to the automatic renewal provision, it has been extended until February 2010. There were approximately 222 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed at December 31, 2008. Midwest Generation had recorded a $52 million liability at December 31, 2008 related to this matter.

Midwest Generation recorded an undiscounted liability for its indemnity for future asbestos claims through 2045. During the fourth quarter of 2007, the liability was reduced by $9 million based on updated estimated losses. In calculating future losses, various assumptions, were made 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 no asbestos claims will be filed after 2044.

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 valid 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. See "EMG: Other Developments — EME Homer City New Source Review Notice of Violation" for discussion of the NOV received by EME Homer City and associated indemnity claims. 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, 2008 and 2007, EME had recorded a liability of $95 million (of which $51 million is classified as a current liability) 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. At December 31, 2008, EME had recorded a liability of $13 million related to these matters.

Capacity Indemnification Agreements

As of December 31, 2008, EME has a 50% interest in the March Point project. 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. The obligations under this indemnification agreement as of December 31, 2008, if payment were required, would be $56 million, which is EME's maximum exposure to loss as EME fully impaired its equity investment in the project in 2005. EME has not recorded a liability related to the indemnity.

Indemnity Provided as Part of the Acquisition of Mountainview

In connection with the acquisition of Mountainview, SCE agreed to indemnify the seller with respect to specific environmental claims related to SCE's previously owned San Bernardino Generating Station, divested by SCE in 1998 and reacquired as part of the Mountainview acquisition. SCE retained certain responsibilities with respect to environmental claims as part of the original divestiture of the station. The aggregate liability for either party to the purchase agreement for damages and other amounts is a maximum of $60 million. This indemnification for environmental liabilities expires on or before March 12, 2033. SCE has not recorded a liability related to this indemnity.

Mountainview Filter Cake Indemnity

Mountainview owns and operates a power plant in Redlands, California. The plant utilizes water from on-site groundwater wells and City of Redlands (City) recycled water for cooling purposes. Unrelated to the operation of the plant, this water contains perchlorate. The pumping of the water removes perchlorate from the aquifer beneath the plant and concentrates it in the plant's wastewater treatment "filter cake." Use of this impacted groundwater for cooling purposes was mandated by Mountainview's California Energy Commission permit. Mountainview has indemnified the City for cleanup or associated actions related to groundwater contaminated by perchlorate due to the disposal of filter cake at the City's solid waste landfill. The obligations under this agreement are not limited to a specific time period or subject to a maximum liability. SCE has not recorded a liability related to this guarantee.

Other Edison International Indemnities

Edison International provides other indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, and specified environmental indemnities and income taxes with respect to assets sold. Edison International's obligations under these agreements may be limited in terms of time and/or amount, and in some instances Edison International may have recourse against third parties for certain indemnities. The obligated amounts of these indemnifications often are not explicitly stated, and the overall maximum amount of the obligation under these indemnifications cannot be reasonably estimated. Edison International has not recorded a liability related to these indemnities.

OFF-BALANCE SHEET TRANSACTIONS

This section of the MD&A discusses off-balance sheet transactions at EMG. SCE does not have off-balance sheet transactions. Included are discussions of investments accounted for under the equity method for both subsidiaries, as well as sale-leaseback transactions at EME, EME's obligations to one of its subsidiaries, and leveraged leases at Edison Capital.

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 on 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.

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. 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. In certain projects, long-term debt to finance the assets constructed was secured. 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, 2008, entities which EME has accounted for under the equity method had indebtedness of $294 million, of which $128 million is proportionate to EME's ownership interest in these projects.

Edison Capital has invested in affordable housing projects utilizing partnership or limited liability companies in which Edison Capital is a limited partner or limited liability member. In these entities, Edison Capital usually owns a 99% interest. With a few exceptions, an unrelated general partner or managing member exercises operating control; voting rights of Edison Capital are limited by agreement to certain significant organizational matters. Edison Capital has subsequently sold a majority of these interests to unrelated third party investors through syndication partnerships in which Edison Capital has retained an interest, with one exception, of less than 20%. The debt of those partnerships and limited liability companies is secured by real property and is nonrecourse to Edison Capital, except in limited cases where Edison Capital has guaranteed the debt. At December 31, 2008, Edison Capital had made guarantees to lenders in the amount of $1.4 million.

Edison Capital has also invested in three limited partnership funds which make investments in infrastructure and infrastructure-related projects. Those funds follow special investment company accounting which requires the fund to account for its investments at fair value. Although Edison Capital would not follow special investment company accounting if it held the funds' investment directly, Edison Capital records its proportionate share of the funds' results as required by the equity method.

At December 31, 2008, entities that Edison Capital has accounted for under the equity method had indebtedness of approximately $1.5 billion, of which approximately $648 million is proportionate to Edison Capital's ownership interest in these projects. Substantially all of this debt is nonrecourse to Edison Capital.

Sale-Leaseback Transactions

EME has entered into sale-leaseback transactions related to the Powerton Station and Units 7 and 8 of the Joliet Station in Illinois and the Homer City facilities in Pennsylvania. For further discussion, see "Edison International: Management Overview," "Critical Accounting Estimates and Policies — Off-Balance Sheet Financing" and "Commitments, Guarantees and Indemnities — Operating and Capital Leases."

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 of $46 million, $54 million and $61 million in 2008, 2007 and 2006, 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 (In millions)	Amount of Lessor Debt at December 31, 2008	Maturity Date of Lessor Debt
Powerton/Joliet	$ 1,367	PSEG/Citigroup, Inc.	$ 238	$ 119 Series A	2009
				679 Series B	2016
Homer City	1,591	GECC/ Metropolitan Life Insurance Company	798	$ 237 Series A	2019
				510 Series B	2026

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

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 on EME's consolidated balance sheet. In accordance with GAAP, EME records rent expense on a levelized basis over the terms of the respective leases. The following table summarizes the lease payments and rent expense for the three years ended December 31, 2008.

In millions Years Ended December 31,	2008	2007	2006
Cash payments under plant operating leases			
Powerton and Joliet facilities	**$ 185**	$ 185	$ 185
Homer City facilities	**152**	151	152
Total cash payments under plant operating leases	**$ 337**	$ 336	$ 337
Rent expense			
Powerton and Joliet facilities	**$ 75**	$ 75	$ 75
Homer City facilities	**102**	102	102
Total rent expense	**$ 177**	$ 177	$ 177

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, 2008 and 2007, prepaid rent on these leases was $878 million and $716 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."

Leveraged Leases

Edison Capital is the lessor in various power generation, electric transmission and distribution, transportation and telecommunications leases. The debt in these leveraged leases is nonrecourse to Edison Capital and is not recorded on Edison International's balance sheet in accordance with SFAS No. 13, "Accounting for Leases."

At December 31, 2008, Edison Capital had net investments, before deferred taxes, of $2.5 billion in its leveraged leases, with nonrecourse debt in the amount of $5.0 billion. As further described in "Other Developments — Federal and State Income Taxes," the IRS has raised issues in the audit of Edison International's tax returns with respect to certain leveraged leases at Edison Capital.

OTHER DEVELOPMENTS

Environmental Matters

The operating subsidiaries of Edison International are subject to numerous federal and state environmental laws and regulations, which require them to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment. Edison International believes that its operating subsidiaries are in substantial compliance with existing environmental regulatory requirements. However, the US EPA has issued a NOV to Midwest Generation and Commonwealth Edison, the former owner of Midwest Generation's coal-fired power plants, alleging violations of the CAA and certain opacity and particulate matter standards. For information on the US EPA NOV issued to Midwest

Generation, see "EMG: Other Developments — Midwest Generation Potential Environmental Proceeding" above.

The domestic power plants owned or operated by Edison International's operating subsidiaries, in particular their coal-fired plants, may be affected by recent developments in federal and state environmental laws and regulations. These laws and regulations, including those relating to SO_2 and NO_x emissions, mercury emissions, ozone and fine particulate matter emissions, regional haze, water quality, and climate change, may require significant capital expenditures at these facilities. The developments in certain of these laws and regulations are discussed in more detail below. These developments will continue to be monitored to assess what implications, if any, they will have on the operation of domestic power plants owned or operated by SCE, EME, or their subsidiaries, or the impact on Edison International's consolidated results of operations or financial position.

Climate Change

Federal Legislative Initiatives

Currently a number of bills are proposed or under discussion in Congress to mandate reductions of GHG emissions. At this point, it cannot be determined whether any of these proposals will be enacted into law or to estimate their potential effect on the operations of Edison International's subsidiaries. The ultimate outcome of the debate about GHG emission regulation on the federal level could have a significant economic effect on the operations of Edison International's subsidiaries. Any legal obligation that would require a substantial reduction in emissions of carbon dioxide or would impose additional costs or charge for the emission of carbon dioxide could have a materially adverse effect on operations.

These costs will depend upon many factors, including the required levels of GHG emission reductions, the timing of those reductions, the impact on fuel prices, whether emissions will be taxed or emission credits will be allocated with or without cost to existing generators, and whether flexible compliance mechanisms, such as a GHG offset program similar to those sanctioned under the CAA for conventional pollutants, will be part of the policy.

While debate continues at the national level over domestic climate policy and the appropriate scope and terms of any federal legislation, many states are developing state-specific measures or participating in regional legislative initiatives to reduce GHG emissions.

Edison International supports a national regulatory program for GHG emission reduction that is market-based, equitable and comprehensive, through which all sources of GHG emissions are regulated and all certifiable means of reducing and offsetting such emissions are recognized. This program should be long-term, and should establish technologically realistic GHG emission reduction targets.

Regional Initiatives

On December 20, 2005, seven northeastern states entered into a Memorandum of Understanding to create a regional initiative to establish a-cap-and trade GHG 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. The RGGI states (now numbering ten states) have passed laws and/or regulations to implement the RGGI program, which commenced in 2009. Pennsylvania is not a signatory to the RGGI, although it has participated as an observer of the process.

In February 2007, the Governors of Arizona, California, New Mexico, Oregon and Washington launched the Western Climate Initiative to develop regional strategies to address climate change. The Western Climate Initiative is identifying, evaluating and implementing collective and cooperative ways to reduce greenhouse gases in the region. Since February 2007, the Governor of Utah and Montana and the Premiers of British Columbia, Manitoba, Ontario and Quebec have joined the Initiative. Other states and provinces have joined as observers. The Initiative partners set an overall regional goal in August 2007 for reducing GHG emissions to 15% below 2005 levels by 2020. In September 2008, the partners released design recommendations for the regional cap-and-trade program intended to help achieve that reduction goal.

On November 15, 2007, Illinois became a party to the Midwestern Accord, in which six of the twelve states in the Midwestern Governors' Association, including Illinois, agreed to seek to develop regional GHG emission reduction goals within one year, and to develop a multi-sector cap-and-trade program to achieve these goals. The Accord called for such a program to be implemented in 30 months. On February 19, 2008, the six participating states announced that they would complete a model rule by the end of 2008 that would create the framework for the cap-and-trade program. The schedule for the model rule has been revised to fall 2009. Once this model rule has been drafted, each of the participating states could adopt the program through legislative action, executive order or other appropriate means. In February 2007, prior to the development of the Midwestern Accord, then-Illinois Governor Blagojevich announced a goal to reduce Illinois' GHG emissions to 1990 levels by 2020 and to 60% below 1990 levels by 2050.

Implementing regulations for such regional initiatives are likely to vary from state to state and may be more stringent and costly than federal legislative proposals currently being debated in Congress. It cannot yet be determined whether or to what extent any federal legislative system would seek to preempt regional or state initiatives, although such preemption would greatly simplify compliance and eliminate regulatory duplication.

State-Specific Legislation

In September 2006, California enacted two laws regarding GHG emissions. The first, known as AB 32 or the California Global Warming Solutions Act of 2006, establishes a comprehensive program to begin in 2012 to achieve reductions of GHG emissions. The second law, known as SB 1368, required the CPUC and the CEC, respectively, to adopt GHG emission performance standards, known as EPS, for investor owned and publicly owned utilities, respectively, for long-term procurement of electricity. These standards must equal the performance of a combined-cycle gas turbine generator.

AB 32 required the CARB to approve a scoping plan for achieving the maximum technologically feasible and cost-effective reductions in GHG emissions on or before January 1, 2009. On December 11, 2008, the CARB approved a proposed scoping plan which was largely unchanged from the original draft scoping plan that was released in June 2008. However, the revised draft scoping plan does not include the more aggressive energy efficiency or coal emission reduction standard measures that were under evaluation for inclusion in the proposed draft scoping plan. The preliminary recommendations in the proposed scoping plan included: a California cap-and-trade program linked to the Western Climate Initiative covering electricity, transportation, residential/commercial, and industrial sources by 2020; California light-duty vehicle GHG standards; increased energy efficiency, including increasing combined heat and power use; a 33% by 2020 Renewables Portfolio Standard for both Investor-Owned Utilities and publicly-owned utilities; a low-carbon fuel standard; measures to reduce high global warming potential gases; sustainable forest measures; water sector measures; vehicle efficiency measures, goods movement measures; heavy/medium duty vehicle measures; the Million Solar Roofs program; local government actions and regional targets; supporting implementation of a high-speed rail system; recycling and waste measures; agriculture measures; and energy efficiency and co-benefits audits for large industrial sources.

In October 2008, the CPUC and CEC adopted a proposed opinion on GHG regulatory strategies providing additional recommendations to the CARB on measures and strategies for reducing GHG emissions in the electricity and natural gas sectors. The proposed opinion's recommendations address mandatory emission reduction measures including energy efficiency, renewable resources, and expansion of combined heat and power. The recommendations also include design suggestions for a multi-sector, statewide, cap-and-trade program. The Los Angeles Department of Water and Power filed a request for rehearing and reconsideration of the opinion with the CPUC and CEC on November 21, 2008.

AB 32 also required the CARB to adopt regulations requiring the reporting and verification of statewide GHG emissions on or before January 1, 2008. On December 6, 2007 the CARB approved regulations for the mandatory reporting of GHG emissions, including the reporting of GHG emissions for the electricity sector. The CARB directed its staff to make some technical modifications to the proposed regulations, which had been issued in October 2007. The CARB staff issued revised regulations for public comment on May 15 and June 30, 2008. The final regulations became effective on January 1, 2009. SCE and EME are evaluating the CARB's reporting regulations and the scoping plan under AB 32 to assess the total cost of compliance.

The emission performance standards adopted by the CPUC and CEC pursuant to SB 1368 prohibit SCE and other California load-serving entities from entering into long-term financial commitments with generators that emit more than 1,100 pounds of CO_2 per MWh, which would include most coal-fired plants. In January 2008, SCE filed a petition with the CPUC seeking clarification that the emission performance standard would not apply to capital expenditures required by existing agreements among the owners at Four Corners. The CPUC issued a proposed decision finding that the emission performance standard was not intended to apply to capital expenditures at Four Corners requested by SCE in its GRC for the period 2007 – 2011. In October 2008, the Assigned Commissioner and Administrative Law Judge issued a ruling withdrawing the proposed decision and seeking additional comment on whether the finding in the proposed decision should be changed and whether SCE should be allowed to recover such capital expenditures. SCE estimates that its share of capital expenditures approved by the owners at Four Corners since the GHG emission performance standard decision was issued in January 2007 is approximately $43 million, of which approximately $8 million had been expended through December 31, 2008. The ruling also directs SCE to explain why certain information was not included in its petition and why the failure to include such information should not be considered misleading in violation of CPUC rules. SCE filed its response and comments to the ruling in November and December 2008 and cannot predict the outcome of this proceeding or estimate the amount, if any, of penalties or disallowances that may be imposed.

Litigation Developments

Significant climate change litigation, raising issues that may affect the timing and scope of future GHG emission regulation, was brought by a variety of public and private parties in the past several years. As no decisions were handed down in any of the major cases in 2008, it continues to be difficult to determine how the courts will respond to every situation. To date, trial courts that have addressed the cases in which plaintiffs have sought damages or equitable relief directly from power companies and other defendants have dismissed the plaintiff's claims, either because the courts determined that a judicial decision would impermissibly intrude on the powers of the legislative and executive branches to regulate and, as applicable, enter into foreign compacts concerning GHG emissions, or because of the absence of evidence linking any individual defendant's GHG emissions to any harm allegedly incurred by the suing plaintiffs.

On April 2, 2007, the United States Supreme Court issued an opinion in Massachusetts et. al. v. Environmental Protection Agency, et. al., ruling that the US EPA has the authority to regulate GHG emissions of new motor vehicles under the CAA and that it has a duty to determine whether GHG emissions of new motor vehicles contribute to climate change or offer a reasoned explanation for its failure to make such a determination when presented with a request for a rulemaking on the issue by the state claimants. The Court ruled that the US EPA's failure to make the necessary determination or to offer a reasonable explanation for its refusal to do so was impermissible. While this case hinged on a provision of the CAA related to emissions of motor vehicles, a parallel provision of the CAA applies to stationary sources, such as electric generators, and there is litigation pending in the D.C. Circuit Court of Appeals, Coke Oven Task Force v. EPA, in which it is argued that the Massachusetts v. EPA case may be applied to stationary sources such as power plants.

In April 2006, private citizens filed a complaint in federal court in Mississippi against numerous defendants, including Edison International and several electric utilities, arguing that emissions from the defendants' facilities contributed to climate change and seeking monetary damages related to the 2005 hurricane season. In August 2007, the court dismissed the case, and plaintiffs have appealed this dismissal to the Fifth Circuit

Court of Appeals. In February 2008, a native Alaskan village and city filed a complaint in federal court in California against 24 defendants, including Edison International, who directly or through subsidiaries engage in electric generating, oil and gas, or coal mining lines of business. The complaint contends that the alleged global warming impacts of the GHG emissions associated with the defendants' business activities are destroying the plaintiffs' village through the melting of Arctic ice that had previously protected the village from winter storms. The plaintiffs further allege that the village will soon need to be abandoned or relocated at a cost of between $95 million and $400 million. Motions to dismiss the complaint in the California case are currently pending and Edison International cannot predict the outcome of this lawsuit.

Air Quality Regulation

Clean Air Interstate Rule

The CAIR, issued by the US EPA on March 10, 2005, applies to 28 eastern states (including Illinois and Pennsylvania) and the District of Columbia, and is intended to address ozone and fine particulate matter attainment issues by reducing regional SO_2 and NO_x emissions. The CAIR reduces the current CAA Title IV Phase II SO_2 emission 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. Both Illinois and Pennsylvania have developed SIPs to meet CAIR requirements. The Illinois and Pennsylvania SIPs for the CAIR, with the exception for set-asides of NO_x allowances in Illinois, substantively matched the federal CAIR requirements.

In December 2008, the District of Columbia Circuit Court of Appeals remanded the CAIR to the US EPA, without vacating the rule, but with instructions that the US EPA remedy CAIR's flaws in accordance with an earlier opinion of the Court in the same case. That opinion raised significant questions as to whether the US EPA could use cap-and-trade programs for NO_x and SO_2 to remedy upwind contributions to downwind states' noncompliance with national ambient air quality standards for ozone and fine particulate matter. The practical impact of the remand is that CAIR requirements became effective January 1, 2009 and are to remain in place until the US EPA promulgates a revised rule. The timing and substance of the revised rule are not yet clear. There is substantial uncertainty as to how and when the US EPA will address the deficiencies identified by the Court and the impact revised regulations will have on SIPs promulgated to implement the CAIR. In addition, the US EPA has allowed states to rely on compliance with the CAIR to satisfy obligations under other CAA programs, including regional haze regulations and reasonably available control technology requirements. Depending on what happens with respect to the CAIR and the revised SIPs developed as a consequence of the CAIR, the Illinois Plants and the Homer City facilities may be subject to additional requirements pursuant to these programs.

The Illinois Plants continue to be subject to the CAIR. EME expects that compliance with the CAIR, and revised or additional state regulations promulgated to comply with a revised CAIR and/or other air regulatory requirements, could result in increased capital expenditures and operating expenses beyond those already required by the CPS, discussed below.

Illinois

Under the CPS, Midwest Generation is required to achieve specific lower emission rates by specified dates. Midwest Generation has not decided upon a particular combination of retrofits to meet the required step down in emission rates. Midwest Generation continues to review alternatives, including interim compliance solutions. The CPS also specifies that specific control technologies are to be installed on some units by specified dates. In these cases, Midwest Generation must either install the required technology by the specified deadline or shut down the unit.

In order to comply with the CPS, Midwest Generation shut down Unit 6 at the Waukegan Station on December 31, 2007 and must permanently shut down Units 1 and 2 at the Will County Station by December 31, 2010.

The principal emission standards and control technology requirements for NO_x and SO_2 under the CPS are as described below:

NO_x Emissions – Beginning in calendar year 2012 and continuing in each calendar year thereafter, Midwest Generation must comply with an annual and seasonal NO_x emission rate of no more than 0.11 lbs/million Btu. In addition to these standards, Midwest Generation must install and operate SNCR equipment on Units 7 and 8 at the Crawford Station by December 31, 2015.

Midwest Generation is in the process of completing engineering work for the potential installation of SCR equipment on Units 5 and 6 at the Powerton Station and SNCR equipment on Unit 6 at the Joliet Station. The SCR equipment at the Powerton Station is currently estimated to cost $500 million, and the SNCR equipment on Unit 6 at the Joliet Station is currently estimated to cost $13 million (both figures are in 2008 dollars). This technology combination represents one possible compliance plan for the NO_x emission rate. Midwest Generation is evaluating other potential solutions that are less costly to meet the NO_x emission rate that combine the use of alternative NO_x removal technologies with certain unit shutdowns.

SO_2 Emissions – Midwest Generation must comply with an overall SO_2 annual emission rate of:

- 0.44 lbs/million Btu in 2013
- 0.41 lbs/million Btu in 2014
- 0.28 lbs/million Btu in 2015
- 0.195 lbs/million Btu in 2016
- 0.15 lbs/million Btu in 2017
- 0.13 lbs/million Btu in 2018
- 0.11 lbs/million Btu in 2019 and thereafter

In addition to these standards, Midwest Generation must install and operate the following specific emission control technologies by the dates indicated:

- FGD equipment on Unit 7 and Unit 8 at the Waukegan Station by December 31, 2013 and December 31, 2014, respectively.
- FGD equipment on Unit 19 at the Fisk Station by December 31, 2015.
- FGD equipment on Unit 8 and Unit 7 at the Crawford Station by December 31, 2017 and December 31, 2018, respectively.
- FGD equipment on Units 7 and 8 at the Joliet Station, Units 5 and 6 at the Powerton Station, and Units 3 and 4 at the Will County Station by December 31, 2018.

The engineering work at the Powerton Station also included the potential installation of FGD equipment on Units 5 and 6, and Midwest Generation currently estimates approximately $1 billion (in 2008 dollars) of capital expenditures would be required for the FGD equipment at the Powerton Station. Midwest Generation also determined these capital expenditures could be reduced if the construction work sequence of FGD and SCR at the Powerton Station were reversed. The complexity of the Powerton Station installation and construction interferences are representative of the balance of the fleet and Midwest Generation currently estimates approximately $650/kW for any FGD installation it elects to make on other units.

Changes in the cost of labor, equipment, and materials, among other factors, may materially affect the above estimates for SCR, SNCR and FGD equipment.

Compliance Costs and Plans

Decisions to install the improvements described above have not been made. Midwest Generation is still reviewing all technology and unit shutdown combinations, including interim and alternative compliance solutions. These decisions will take into account many factors, including, among others, the effectiveness and cost of various control technologies, the remaining estimated useful life of each affected unit, the market outlook for the prices of various commodities, including electrical energy and capacity, coal and natural gas, availability of financing, and the statutory and regulatory environment including potential GHG regulation. Under current uncertain conditions, Midwest Generation cannot predict the extent to which its interim or long-term compliance with the CPS will result in the retrofit or temporary or permanent suspension or eventual shutdown of a material part of its operating units.

Pennsylvania

On December 18, 2007, the Pennsylvania Environmental Quality Board approved the Pennsylvania CAIR. This rule has been submitted to the US EPA for approval as part of the Pennsylvania SIP. The Pennsylvania CAIR is substantively similar to the CAIR. EME Homer City will be subject to the federal CAIR rule during 2009 and expects to be able to comply with the NO_x requirement using its existing SCR system. The Pennsylvania CAIR, including both NO_x and SO_2 limits, is expected to become effective in 2010. EME Homer City expects to comply with Pennsylvania CAIR through the continued operation of its scrubber on Unit 3 to reduce SO_2 emissions and the purchase of SO_2 allowances.

Clean Air Mercury Rule

By means of a rule published in May 2005, the US EPA established the CAMR, which created the framework for a national, market-based cap-and-trade program to reduce mercury emissions from existing coal-fired power plants to a national cap of 38 tons by 2010 and to 15 tons by 2018, primarily through reductions in mercury achieved by lowering SO_2 and NO_x emissions under the CAIR. States were allowed, but not required, to join the trading program by adopting the CAMR model trading rules. States retained the right to promulgate alternative regulations equivalent to or more stringent than the CAMR cap-and-trade program, as long as the regulations were approved by the US EPA.

At the time that it published the CAMR, the US EPA also published a second rule, formally rescinding its previous finding that mercury emissions from electrical generating facilities had to be regulated as a hazardous air pollutant pursuant to Section 112 of the CAA, which would have imposed technology-based standards on emission sources. Both the CAMR and US EPA's decision to remove oil-and coal-fired plants from the lists of sources to be regulated under Section 112 of the CAA were challenged in the U.S. Court of Appeals for the D.C. Circuit by various environmental groups and state attorneys general.

On February 8, 2008, the D.C. Circuit Court of Appeals vacated both rules and remanded the matter to the US EPA. The United States and the Utility Air Regulatory Group had petitioned the Supreme Court to review the D.C. Circuit's decision, but the United States subsequently filed a motion to withdraw its petition based on a determination by the US EPA to develop a new mercury regulation pursuant to Section 112 of the CAA. The Utility Air Regulatory Group has not withdrawn its petition. The order has been appealed to the U.S. Supreme Court. Until the US EPA takes action in response to the remand, coal-fired electrical generating units will continue to be sources subject to the requirements of Section 112 of the CAA and will be obligated to comply, on a case-by-case basis, with technology-based standards to control emissions of all hazardous air pollutants (not necessarily limited to mercury) in accordance with the requirements of Section 112. On February 23, 2009, the U.S. Supreme Court declined to review the D.C. Circuit's decision.

Regional Haze

In July 1999, the US EPA published the "Regional Haze Rule" to reduce haze and protect visibility in designated federal areas. The goal of the 1999 rule is to restore visibility in mandatory federal Class I areas, such as national parks and wilderness areas, to natural background conditions by 2064. Sources such as power plants that are reasonably anticipated to contribute to visibility impairment in Class I areas may be required to install Best Available Retrofit Technology (also known as BART) or implement other control strategies to meet regional haze control requirements.

States were required to revise their SIPs by December 2007 to demonstrate reasonable further progress towards meeting regional haze goals. On January 9, 2009, the US EPA found that 37 states, including California, Illinois, Nevada, and Pennsylvania, had failed to submit all or a portion of their regional haze SIPs. For those states that have yet to make a submission, or that have made a submission that does not include particular SIP elements, EPA is making a "finding of failure to submit." The US EPA finding initiates a 2-year deadline for EPA to issue a Federal Implementation Plan or FIP. The FIP will provide the basic program requirements for each State that has not completed an approved plan of its own by January 15, 2011. 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 although, as previously noted, the D.C. Circuit Court's decision to remand the CAIR to the US EPA means that there is substantial uncertainty as to the future of the federal and state CAIR programs. 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 Interstate Rule — 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 are being evaluated by the state.

The US EPA has adopted alternate rules for the area where Four Corners is located. The rules allow nine western states and Native American tribes to follow an alternate implementation plan and schedule for the Class I Areas. This alternate implementation plan is known as the Annex Rule. The US EPA issued a Revised Annex Rule on October 13, 2006, to address a previous challenge and court remand of that rule.

New Mexico

The Regional office of the US EPA (EPA Region 9) requested that Arizona Public Service Company perform a BART analysis for Four Corners. This analysis was completed and submitted it to the US EPA on January 30, 2008. The EPA Region 9 will review Arizona Public Service Company's submission and determine what constitutes BART for Four Corners. Once Arizona Public Service Company receives the EPA Region 9's final determination, it will have five years to complete the installation of the equipment, if required, and to achieve the emission limits established by the EPA Region 9. Until the EPA Region 9 makes a final determination on this matter, SCE cannot accurately estimate the expenditures that may be required. SCE also cannot predict whether the relevant environmental agencies will agree with its BART recommendations or, if the agencies disagree with our recommendations, the nature of the BART controls the agencies may ultimately mandate and the resulting financial or operational impact. In addition, SCE cannot predict whether or not CPUC regulations will permit it to make investments in equipment that may be required.

New Source Review Requirements

Since 1999, the US EPA has pursued a coordinated compliance and enforcement strategy to address CAA NSR compliance issues at the nation's coal-fired power plants. The NSR regulations impose certain requirements on facilities, such as electric generating stations, if modifications are made to air emissions sources at a facility. The US EPA's strategy has included both the filing of suits against a number of power plant owners, and the issuance of administrative NOVs to a number of power plant owners alleging NSR violations. See "EMG: Other Developments — Midwest Generation New Source Review Notice of Violation" and "EMG: Other Developments — EME Homer City New Source Review Notice of Violation" for further discussion.

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. States were 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. Since then, the US EPA has issued more stringent 24-hour fine particulate and ground level ozone standards. The revised SIPs are likely to require additional emission reductions from facilities that are significant emitters of ozone precursors and particulates. Edison International anticipates that further emission reduction obligations will not be imposed under these revised ambient air quality standards until 2015.

Priority Reserve Legal Challenges

In July 2008, the Los Angeles Superior Court found that actions taken by the SCAQMD, in promulgating rules that had made available a "Priority Reserve" of emissions credits for new power generation projects did not satisfy California environmental laws. In November 2008, the Los Angeles Superior Court enjoined the SCAQMD from issuing Priority Reserve emission credits to any facility, including new power projects, until a satisfactory environmental analysis is completed. The writ also ordered the SCAQMD to refrain from taking any action relating to power plant projects approved after August 2007 pursuant to the Priority Reserve rules until the SCAQMD completes a satisfactory environmental analysis. The SCAQMD appealed the Superior Court decision, and in doing so, stayed the injunction against the issuance of permits.

In a letter dated January 9, 2009, which was sent to numerous permit holders, the SCAQMD stated that it "cannot ensure the long-term validity of permits issued on or after August 3, 2007, or possibly on or after September 8, 2006" because the issuance of credits from the Priority Reserve may be considered invalid. As a result, the permits for SCE's four constructed peaker plants, which were issued in March and April 2007 may be in jeopardy (see "SCE: Regulatory Matters — Current Regulatory Developments — Peaker Plant Generation Projects" for further information). However, because the SCAQMD's appeal of the Superior Court decision resulted in the Superior Court's injunction being stayed, existing permits will remain in effect pending the appeal.

Separately, in August 2008, substantially the same plaintiffs sued the SCAQMD in federal court alleging that the emission credits contained in SCAQMD's New Source Review offset accounts (which include the Priority Reserve) are invalid and seeking to enjoin SCAQMD from transferring them. The SCAQMD has filed a motion to dismiss the federal suit. SCE has joined a coalition of other interested parties that have intervened in the federal litigation between the SCAQMD and environmental groups.

SCE is in the process of evaluating the impact of the two lawsuits on certain power-purchase agreements that resulted from its new generation RFO and the potential implications for its long-term resource adequacy requirements. Separately, EMG is evaluating the potential impact on EME's Walnut Creek project. See "EMG: Liquidity — Capital Expenditures — Expenditures for New Projects — Walnut Creek Project."

Water Quality Regulation

Clean Water Act — Prohibition on the Use of Ocean-Based Once-Through Cooling

On March 21, 2008 the California State Water Resources Control Board released its draft scoping document and preliminary draft Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling. This state policy is being developed in advance of the issuance of a final rule from the US EPA on standards for cooling water intake structures at existing large power plants. As anticipated, the Scoping Document establishes closed-cycle wet cooling as the best technology available for retrofitting existing once-through cooled plants like San Onofre. Additionally, the target levels for compliance with the state policy correspond to the high end of the ranges originally proposed in the US EPA's rule. Nuclear-fueled power plants, including San Onofre, would have until January 1, 2021 to comply with the policy. The policy development schedule included in the scoping document scheduled workshops and the submission of public comments in May 2008 and a public hearing in September 2008. The State Board vote has been informally delayed and is currently anticipated to occur in late 2009. This policy may significantly impact both operations at San Onofre and SCE's ability to procure timely supplies of generating capacity from fossil-fueled plants that use ocean water in once-through cooling systems.

Proposed California Senate Bill

In January 2009, a bill (SB 42) was introduced in the California State Senate which would prohibit power plants and other industrial facilities from using once-through cooling methods on or after January 1, 2015. For the period from January 1, 2011 to December 31, 2014 any power plant or other facility using once-through cooling methods would be required to pay a seawater fee of $0.15 per 10,000 gallons used. The cost to San Onofre for the use of seawater for Units 2 and 3 would total approximately $12 million annually. SCE and Edison International oppose this bill because it does not take into account environmental, economic or grid reliability impacts.

State Water Quality Standards

Illinois

On October 26, 2007, the Illinois EPA filed a proposed rule with the Illinois PCB that would establish more stringent thermal and effluent water quality standards for the Chicago Area Waterway System and Lower Des Plaines River. Midwest Generation's Fisk, Crawford and Will County stations all use water from the Chicago Area Waterway System and its Joliet Station uses water from the Lower Des Plaines River for cooling purposes. The rule, if implemented, is expected to affect the manner in which those stations use water for station cooling.

The proposed rule is the subject of an administrative proceeding before the Illinois PCB and must be approved by the Illinois PCB and the Illinois Joint Committee on Administrative Rules. Following state adoption and approval, the US EPA also must approve the rule. Hearings began on January 28, 2008, and are continuing in 2009. Midwest Generation is a party in those proceedings. At this time, it is not possible to predict the timing for resolution of the proceeding, the final form of the rule, or how it would impact the operation of the affected stations; however, significant capital expenditures may be required depending on the form of the final rule.

Pennsylvania Selenium Discharge Order

The discharge from the treatment plant receiving the wastewater stream from EME's Unit 3 FGD 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. EME Homer City and the PADEP have entered into a consent order and agreement related to selenium discharge, which was entered by the Pennsylvania state court on July 17, 2007. Under the consent order and agreement, EME Homer City paid a civil penalty of $200,000 and agreed to install modifications to its wastewater system to achieve consistent compliance with discharge limits. EME Homer City has experienced very few exceedances since entering into the consent order and agreement.

Environmental Remediation

Edison International is subject to numerous environmental laws and regulations, which require it to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment.

Edison International believes that it is in substantial compliance with environmental regulatory requirements; however, possible future developments, such as the enactment of more stringent environmental laws and regulations, could affect the costs and the manner in which business is conducted and could cause substantial additional capital expenditures. There is no assurance that additional costs would be recovered from customers or that Edison International's financial position and results of operations would not be materially affected.

Edison International records its environmental remediation liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. Edison International reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site using currently available information, including existing technology, presently enacted laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. These estimates include costs for site investigations, remediation, operations and maintenance, monitoring and site closure. Unless there is a probable amount, Edison International records the lower end of this reasonably likely range of costs (classified as other long-term liabilities) at undiscounted amounts.

As of December 31, 2008, Edison International's recorded estimated minimum liability to remediate its 45 identified sites at SCE (24 sites) and EME (21 sites primarily related to Midwest Generation) was $45 million, $41 million of which was related to SCE including $10 million related to San Onofre. This remediation liability is undiscounted. Edison International's other subsidiaries have no identified remediation sites. The ultimate costs to clean up Edison International's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. Edison International believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $173 million, all of which is related to SCE. The upper limit of this range of costs was estimated using assumptions least favorable to Edison International among a range of reasonably possible outcomes. In addition to its identified sites (sites in which the upper end of the range of costs is at least $1 million), SCE also has 30 immaterial sites whose total liability ranges from $3 million (the recorded minimum liability) to $9 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $29 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $40 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

Edison International's identified sites include several sites for which there is a lack of currently available information, including the nature and magnitude of contamination, and the extent, if any, that Edison International may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can be made for these sites.

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $11 million to $31 million. Recorded costs were $29 million, $25 million and $14 million for 2008, 2007 and 2006, respectively.

Based on currently available information, Edison International believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range for its identified sites and, based upon the CPUC's regulatory treatment of environmental remediation costs incurred at SCE, Edison International believes that costs ultimately recorded will not materially affect its results of operations or financial position. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

Federal and State Income Taxes

Tax Positions being Addressed as Part of Active Examinations, Administrative Appeals and the Global Settlement

In the normal course, Edison International's federal income tax returns are examined by the IRS and Edison International challenges deficiency adjustments, asserted as part of an examination, to the Administrative Appeals branch of the IRS (IRS Appeals) to the extent Edison International believes its tax reporting positions properly complied with the relevant tax law and that the IRS' basis for making such adjustments lacks merit. Edison International has challenged certain IRS deficiency adjustments, asserted as part of the examination of tax years 1994 – 1999 with IRS Appeals. Edison International has also been under active IRS examination for tax years 2000 – 2002 and during the third quarter of 2008, the IRS commenced an examination of tax years 2003 – 2006. In addition, the statute of limitations remains open for tax years 1986 – 1993, which has allowed Edison International to file certain affirmative claims related to these tax years.

Most of the tax positions that Edison International is addressing with IRS Appeals relate to the timing of when deductions for federal income tax purposes are allowed to be reflected on filed income tax returns and, as such, any deductions not sustained would be deductible on future tax returns filed by Edison International. However, any penalties and interest associated with disallowed deductions would result in a permanent cost. Edison International has also filed affirmative claims with respect to certain tax years 1986 through 2005 with the IRS and state tax authorities. At this time, there has not been a final determination of these affirmative claims by the IRS or state tax authorities. Benefits, if any, associated with these affirmative claims would be recorded in accordance with FIN 48 which provides that recognition would occur at the earlier of when Edison International would make an assessment that the affirmative claim position has a more likely than not probability of being sustained or when a settlement of the affirmative claim is consummated with the tax authority. Certain of these affirmative claims have been recognized as part of the implementation of FIN 48.

Edison International has been engaged in settlement negotiations with the IRS to reach a Global Settlement described below of all unresolved tax disputes and affirmative claims for tax years 1986 – 2002 and to resolve cross-border, leveraged-lease issues in their entirety.

In addition to the IRS audits, Edison International's California and other state income tax returns are, in the normal course, subjected to examination by the California Franchise Tax Board and the other state tax authorities. The Franchise Tax Board has substantially completed its examination of all tax years through 2002 and is currently awaiting resolution of the IRS audit before finalizing the audit for these tax years. Edison International is currently under active examination for tax years 2003 – 2004 and remains subject to examination by the California Franchise Tax Board for tax years 2005 and forward.

Edison International filed amended California Franchise tax returns for tax years 1997 – 2002 to mitigate the possible imposition of California non-economic substance penalty provisions on transactions that may be considered as Listed or substantially similar to Listed Transactions described in an IRS notice that was published in 2001. These transactions include certain Edison Capital leveraged-lease transactions and an SCE subsidiary contingent liability company transaction, described below. Edison International filed these amended returns under protest retaining its appeal rights.

The issues discussed below are included in the ongoing IRS examination and appeals process and are included in the scope of issues being addressed as part of the Global Settlement process.

Balancing Account Over-Collections

In response to an affirmative claim filed by Edison International related to balancing account over-collections, the IRS issued a Notice of Proposed Adjustment in July 2007 as part of the ongoing IRS examinations and administrative appeals processes. The tax years to which adjustments are made pursuant to this Notice of Proposed Adjustment are included in the scope of the Global Settlement process. The cash and earnings impacts of this position are dependent on the ultimate settlement of all open tax issues, including this issue, in these tax years. Edison International expects that resolution of this issue could potentially increase earnings and cash flows within the range of $70 million to $80 million and $300 million to $350 million, respectively.

Contingent Liability Company

The IRS has asserted tax deficiencies and penalties of $53 million and $22 million, respectively, for tax years 1997 – 1999 with respect to a transaction entered into by a former SCE subsidiary which the IRS has asserted to be substantially similar to a Listed Transaction described by the IRS as a contingent liability company.

Cross-Border Lease Transactions

As part of a nationwide challenge of cross border lease transactions, the IRS has asserted deficiencies related to Edison International's deferral of income taxes associated with certain of its cross-border, leveraged leases.

These asserted deficiencies relate to Edison Capital's income tax treatment of both its foreign power plant and electric locomotive sale/leaseback transactions entered into in 1993 and 1994 (Replacement Leases, which the IRS refers to as sale-in/lease-out or SILOs) and its foreign power plants and electric transmission system lease/leaseback transactions entered into in 1997 and 1998 (Lease/Leaseback, which the IRS refers to as lease-in/lease-out or LILOs). For tax years 1994 – 1999, Edison International is challenging the asserted deficiencies in ongoing IRS appeals proceedings and is seeking to resolve the asserted deficiencies as part of the Global Settlement process.

In 1999, Edison Capital entered into a lease/service contract transaction involving a foreign telecommunication system (Service Contract, which the IRS refers to as a SILO). As part of an ongoing examination of 2000 – 2002, the IRS examination branch has been reviewing Edison International's income tax treatment of this Service Contract. The income tax treatment of the Service Contract is included in the Global Settlement process for all tax years.

The following table summarizes estimated federal and state income taxes deferred from these leases as of December 31, 2008. Repayment of the entire amount of the deferred income taxes, as provided in the table below, would be accelerated if Edison International and the IRS were unable to reach a settlement and the IRS position were sustained in litigation:

In millions	Tax Years Under Appeal 1994 – 1999	Tax Years Under Audit 2000 – 2006	Unaudited Tax Years 2007 – 2008	Total
Replacement Leases (SILO)	$ 44	$ 42	$ 7	$ 93
Lease/Leaseback (LILO)	563	572	(32)	1,103
Service Contract (SILO)	—	326	110	436
Total	**$ 607**	**$ 940**	**$ 85**	**$ 1,632**

As of December 31, 2008, the after-tax interest on the proposed tax adjustments is estimated to be approximately $643 million. The IRS has also asserted a 20% penalty on any sustained adjustment (other than with respect to the Service Contract).

Edison International believes that its maximum earnings exposure related to these leases, measured as of December 31, 2008, is approximately $1.3 billion after taxes, calculated by reclassifying deferred income taxes to current, re-computing the cumulative earnings under the leases in accordance with lease accounting rules (FASB Staff Position FAS 13-2), and recording interest related to the current income tax liability. Interest will continue to accrue until the alleged deficiency is resolved. This exposure does not include IRS asserted penalties of 20%, as Edison International does not believe that even if the tax return positions taken by Edison Capital are successfully challenged by the IRS that these penalties would be sustained. The current and future earnings and cash positions of SCE and EME are virtually unaffected by these leases.

During the second quarter of 2008, there were court decisions involving income taxation of cross-border leveraged leases that were adverse to the taxpayers involved. These developments underscore the uncertain nature of tax conclusions in this area. Despite these developments, Edison International believes it properly reported these transactions based on applicable statutes, regulations and case law and, in the absence of any settlement with the IRS, will continue to vigorously defend its tax treatment of these leases. Edison International will continue to monitor and evaluate its lease transactions with respect to future events. Future adverse developments, including further adverse case law developments, could change Edison International's current conclusions.

Global Settlement

As previously disclosed, Edison International has negotiated the material terms of a Global Settlement with the IRS which, if consummated, would resolve cross-border, leveraged lease issues in their entirety and all other outstanding tax disputes for open tax years 1986 through 2002, including certain affirmative claims for unrecognized tax benefits. See "Edison International Notes to Consolidated Financial Statements — Note 4. Income Taxes." Consummation of the Global Settlement is subject to review by the Staff of the Joint Committee on Taxation, a committee of the United States Congress (the "Joint Committee"). The IRS submitted the pertinent terms of the Global Settlement to the Joint Committee during the fourth quarter of 2008, and its response is currently pending. Edison International cannot predict the timing of when the Joint Committee will complete its review. Moreover, Edison International cannot predict whether the Joint Committee will concur with the settlement terms negotiated by the IRS for the Global Settlement issues and whether any non-concurrence would result in the IRS proposing different settlement terms. Failure to consummate the Global Settlement and to be successful in any ensuing litigation over issues included in the Global Settlement process, including asserted deficiencies regarding the cross-border leases, could have an adverse affect on Edison International.

In the first quarter of 2009, Edison International terminated two of the six cross-border leveraged leases. The timing for terminating the remaining cross-border leases is uncertain and could occur prior to the Joint Committee completing its work or otherwise prior to consummation of the settlement. Edison Capital and its subsidiaries have reached an agreement based on executed term sheets with all of the counterparties to its SILOs and LILOs which contemplate termination of the leases subject to a final settlement agreement with the IRS. Certain of these agreements are not binding on Edison Capital or the counterparties until such termination. Upon termination of the leases, the lessees would be required to make termination payments from certain collateral deposits associated with the leases, and Edison International would no longer recognize earnings from such leases. In 2008 income from leveraged leases was $28 million. If all settlements included in the Global Settlement process were ultimately concluded consistent with the terms submitted to the Joint Committee, Edison International would expect that the settlement of the disputed lease issues and the resolution of the above-mentioned affirmative claims would result in a portion of any charge initially recorded upon termination of the leases being offset and/or reduced, and the net after-tax earnings charge that would remain is currently expected to be less than half of the maximum after-tax earnings exposure, calculated as of December 31, 2008, discussed above. Furthermore, if all settlements included in the Global Settlement discussions were ultimately concluded consistent with the terms submitted to the Joint Committee, the net cash impact upon Edison International as a whole of the Global Settlement and lease terminations would be positive over time. Termination of the leases prior to consummation of the settlements would result in Edison International initially recording an after-tax charge to earnings currently estimated to be at least $650 million (and potentially up to the maximum earnings exposure indicated above), which would be reduced and/or offset upon completion of the Global Settlement.

To the extent that Edison International is unable to consummate the Global Settlement or other acceptable settlement with the IRS, Edison International will continue to vigorously defend its tax treatment of the leases and is prepared to take legal action. If Edison International were to commence litigation in certain forums, it would need to make payments of the disputed taxes, along with interest and any penalties asserted by the IRS, and thereafter pursue refunds. In the United States Tax Court, no upfront payment would be required. In 2006, Edison International paid $111 million of the taxes, interest and penalties for tax year 1999 followed by a refund claim for the same amount. The IRS did not act on this refund claim within the statutory period, which provides Edison International with the option of being able to take legal action to assert its refund claim. To the extent an acceptable settlement is not reached with the IRS, Edison International, based on its preference for litigation forum, may file refund claims for any taxes, interest and penalties paid for tax years related to these leases. However, Edison International has not decided whether and to what extent it would make additional payments related to later tax years to fund its right to litigate in certain forums should the Global Settlement, or another settlement, not be consummated.

If and when Edison International and the IRS consummate a settlement, Edison International will file amended tax returns with the Franchise Tax Board and other state administrative agencies, for those states in which Edison International has an income tax filing requirement, to reflect the respective state income tax impact of the settlement terms.

Management's Responsibility for Financial Reporting

The management of Edison International is responsible for the integrity and objectivity of the accompanying financial statements and related information. The statements have been prepared in accordance with accounting principles generally accepted in the United States of America and are based, in part, on management estimates and judgment. Management believes that the financial statements fairly reflect Edison International's financial position and results of operations.

As a further measure to assure the ongoing objectivity and integrity of financial information, the Audit Committee of the Board of Directors, which is composed of independent directors, meets periodically, both jointly and separately, with management, the independent auditors and internal auditors, who have unrestricted access to the Committee. The Committee annually appoints a firm of independent auditors to conduct an audit of Edison International's financial statements and internal control over financial reporting; reviews accounting, internal control, auditing and financial reporting issues; and is advised of management's actions regarding financial reporting and internal control matters.

Edison International and its subsidiaries maintain high standards in selecting, training and developing personnel to assure that its operations are conducted in conformity with applicable laws and are committed to maintaining the highest standards of personal and corporate conduct. Management maintains programs to encourage and assess compliance with these standards.

Edison International's independent registered public accounting firm, PricewaterhouseCoopers LLP, are engaged to audit the financial statements included in this Annual Report in accordance with the standards of the Public Company Accounting Oversight Board (United States) and has issued an attestation report on Edison International's internal controls over financial reporting, as stated in their report which is included in this Annual Report on the following page.

Management's Report on Internal Control over Financial Reporting

Edison International's management is responsible for establishing and maintaining adequate internal control over financial reporting (as that term is defined in Rule 13a-15(f) under the Exchange Act). Under the supervision and with the participation of its Chief Executive Officer and Chief Financial Officer, Edison International's management conducted an evaluation of the effectiveness of internal control over financial reporting based on the framework set forth in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on its evaluation under the COSO framework, Edison International's management concluded that internal control over financial reporting was effective as of December 31, 2008. Edison International's internal control over financial reporting as of December 31, 2008 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report on the financial statements in Edison International's 2008 Annual Report to shareholders, which is incorporated herein by this reference.

Disclosure Controls and Procedures

The certifications of the Chief Executive Officer and Chief Financial Officer that are required by Section 302 of the Sarbanes-Oxley Act of 2002 are included as exhibits to Edison International's annual report on Form 10-K. In addition, in 2008, Edison International's Chief Executive Officer provided to the New York Stock Exchange (NYSE) the Annual CEO Certification regarding Edison International's compliance with the NYSE's corporate governance standards.

To the Board of Directors and Shareholders of Edison International

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows present fairly, in all material respects, the financial position of Edison International (the "Company") and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Notes 1, 4, 5 and 10 to the consolidated financial statements, the Company changed the manner in which it accounts for stock-based compensation as of January 1, 2006, defined benefit pension and other post retirement plans as of December 31, 2006, uncertain tax positions as of January 1, 2007, and margin and cash collateral deposits related to derivative positions and fair value measurement and disclosure accounting principles as of January 1, 2008.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Los Angeles, California
March 2, 2009

Consolidated Statements of Income			Edison International
In millions, except per-share amounts **Year ended December 31,**	**2008**	**2007**	**2006**
Electric utility	**$ 11,246**	$ 10,231	$ 9,859
Nonutility power generation	**2,808**	2,575	2,228
Financial services and other	**58**	62	82
Total operating revenue	**14,112**	12,868	12,169
Fuel	**2,147**	1,875	1,757
Purchased power	**3,845**	3,235	3,099
Other operation and maintenance	**4,288**	4,065	3,721
Depreciation, decommissioning and amortization	**1,313**	1,181	1,105
Contract buyout/termination and other	**(44)**	3	(2)
Total operating expenses	**11,549**	10,359	9,680
Operating income	**2,563**	2,509	2,489
Interest and dividend income	**62**	154	169
Equity in income from partnerships and unconsolidated subsidiaries – net	**31**	79	79
Other nonoperating income	**113**	95	133
Interest expense – net of amounts capitalized	**(700)**	(752)	(806)
Other nonoperating deductions	**(125)**	(45)	(63)
Loss on early extinguishment of debt	**—**	(241)	(146)
Income from continuing operations before tax and minority interest	**1,944**	1,799	1,855
Income tax expense	**596**	492	582
Dividends on preferred and preference stock of utility not subject to mandatory redemption	**51**	51	51
Minority interest	**82**	156	139
Income from continuing operations	**1,215**	1,100	1,083
Income (loss) from discontinued operations – net of tax	**—**	(2)	97
Income before accounting change	**1,215**	1,098	1,180
Cumulative effect of accounting change – net of tax	**—**	—	1
Net income	**$ 1,215**	$ 1,098	$ 1,181
Weighted-average shares of common stock outstanding	**326**	326	326
Basic earnings (loss) per share:			
Continuing operations	**$ 3.69**	$ 3.34	$ 3.28
Discontinued operations	**—**	(0.01)	0.30
Total	**$ 3.69**	$ 3.33	$ 3.58
Weighted-average shares, including effect of dilutive securities	**329**	331	330
Diluted earnings (loss) per share:			
Continuing operations	**$ 3.68**	$ 3.32	$ 3.27
Discontinued operations	**—**	(0.01)	0.30
Total	**$ 3.68**	$ 3.31	$ 3.57
Dividends declared per common share	**$ 1.225**	$ 1.175	$ 1.10

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

Consolidated Statements of Comprehensive Income			**Edison International**
In millions **Year ended December 31,**	**2008**	**2007**	**2006**
Net income	**$ 1,215**	$ 1,098	$ 1,181
Other comprehensive income (loss), net of tax:			
Foreign currency translation adjustments – net of income tax benefit of $2, $1 and $1 for 2008, 2007 and 2006, respectively	**(3)**	(2)	(1)
Pension and postretirement benefits other than pensions:			
Net loss arising during period – net of income tax benefit of $23 and $1 for 2008 and 2007, respectively	**(36)**	(2)	—
Amortization of net loss included in expense – net of income tax expense of $3 for 2007	**—**	5	—
Prior service cost arising during the period – net	**(1)**	—	—
Amortization of prior service included in expense – net	**(1)**	(1)	—
Minimum pension liability adjustment	**—**	—	(1)
Unrealized gains (losses) on cash flow hedges:			
Unrealized gains (losses) arising during the period – net of income tax expense (benefit) of $138, $(160) and $214 for 2008, 2007 and 2006, respectively	**211**	(234)	314
Reclassification adjustment for gains (losses) included in net income – net of income tax expense of $58, $45 and $9 for 2008, 2007 and 2006, respectively	**89**	64	12
Other comprehensive income (loss)	**259**	(170)	324
Comprehensive income	**$ 1,474**	$ 928	$ 1,505

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

Consolidated Balance Sheets		**Edison International**
In millions December 31,	**2008**	**2007**
ASSETS		
Cash and equivalents	**$ 3,916**	$ 1,441
Short-term investments	**7**	81
Receivables, less allowances of $39 and $34 for uncollectible accounts at respective dates	**1,006**	1,033
Accrued unbilled revenue	**328**	370
Fuel inventory	**163**	116
Materials and supplies	**390**	316
Derivative assets	**327**	109
Restricted cash	**3**	3
Margin and collateral deposits	**105**	121
Regulatory assets	**605**	197
Accumulated deferred income taxes – net	**104**	167
Other current assets	**399**	290
Total current assets	**7,353**	4,244
Nonutility property – less accumulated provision for depreciation of $2,019 and $1,765 at respective dates	**5,374**	4,906
Nuclear decommissioning trusts	**2,524**	3,378
Investments in partnerships and unconsolidated subsidiaries	**229**	272
Investments in leveraged leases	**2,467**	2,473
Other investments	**89**	96
Total investments and other assets	**10,683**	11,125
Utility plant, at original cost:		
Transmission and distribution	**20,006**	18,940
Generation	**1,819**	1,767
Accumulated provision for depreciation	**(5,570)**	(5,174)
Construction work in progress	**2,454**	1,693
Nuclear fuel, at amortized cost	**260**	177
Total utility plant	**18,969**	17,403
Derivative assets	**244**	122
Restricted cash	**43**	48
Rent payments in excess of levelized rent expense under plant operating leases	**878**	716
Regulatory assets	**5,414**	2,721
Other long-term assets	**1,031**	1,144
Total long-term assets	**7,610**	4,751
Total assets	**$ 44,615**	$ 37,523

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

In millions, except share amounts December 31,	2008	2007
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt	**$ 2,143**	$ 500
Long-term debt due within one year	**174**	18
Accounts payable	**1,031**	979
Accrued taxes	**590**	49
Accrued interest	**187**	160
Counterparty collateral	**8**	42
Customer deposits	**228**	219
Book overdrafts	**224**	212
Derivative liabilities	**178**	125
Regulatory liabilities	**1,111**	1,019
Other current liabilities	**823**	933
Total current liabilities	**6,697**	4,256
Long-term debt	**10,950**	9,016
Accumulated deferred income taxes – net	**5,717**	5,196
Accumulated deferred investment tax credits	**109**	114
Customer advances	**137**	155
Derivative liabilities	**776**	101
Accumulated provision for pensions and benefits	**2,860**	1,089
Asset retirement obligations	**3,042**	2,892
Regulatory liabilities	**2,481**	3,433
Other deferred credits and other long-term liabilities	**1,137**	1,617
Total deferred credits and other liabilities	**16,259**	14,597
Total liabilities	**33,906**	27,869
Commitments and contingencies (Note 6)		
Minority interest	**285**	295
Preferred and preference stock of utility not subject to mandatory redemption	**907**	915
Common stock, no par value (325,811,206 shares outstanding at each date)	**2,272**	2,225
Accumulated other comprehensive income (loss)	**167**	(92)
Retained earnings	**7,078**	6,311
Total common shareholders' equity	**9,517**	8,444
Total liabilities and shareholders' equity	**$ 44,615**	$ 37,523

Authorized common stock is 800 million shares at each reporting period

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

Consolidated Statements of Cash Flows			**Edison International**
In millions **Year ended December 31,**	**2008**	**2007**	**2006**
Cash flows from operating activities:			
Net income	**$ 1,215**	$ 1,098	$ 1,181
Less: income (loss) from discontinued operations	**—**	(2)	97
Income from continuing operations	**1,215**	1,100	1,084
Adjustments to reconcile to net cash provided by operating activities:			
Cumulative effect of accounting change – net of tax	**—**	—	(1)
Depreciation, decommissioning and amortization	**1,313**	1,181	1,105
Net earnings is nuclear ARO regulatory assets and liabilities	**(10)**	143	130
Other amortization	**106**	111	99
Contract buyout/termination and other	**(44)**	3	(2)
Stock-based compensation	**34**	37	47
Minority interest	**82**	156	139
Deferred income taxes and investment tax credits	**207**	(39)	(136)
Equity in income from partnerships and unconsolidated subsidiaries-net	**(31)**	(75)	(76)
Income from leveraged leases	**(51)**	(49)	(67)
Regulatory assets	**(2,725)**	503	74
Regulatory liabilities	**(221)**	176	336
Loss on early extinguishment of debt	**—**	241	146
Levelized rent expense	**(162)**	(160)	(161)
Derivative assets	**41**	(9)	260
Derivative liabilities	**808**	(184)	285
Other assets	**224**	(180)	(231)
Other liabilities	**1,344**	195	309
Margin and collateral deposits – net of collateral received	**(19)**	75	193
Receivables and accrued unbilled revenue	**170**	(59)	208
Inventory and other current assets	**(204)**	(121)	(68)
Book overdrafts	**16**	72	—
Accrued interest and taxes	**367**	12	(123)
Accounts payable and other current liabilities	**(242)**	33	(137)
Distributions and dividends from unconsolidated entities	**(8)**	33	61
Operating cash flows from discontinued operations	**—**	(2)	94
Net cash provided by operating activities	**2,210**	3,193	3,568
Cash flows from financing activities:			
Long-term debt issued	**2,632**	2,930	2,350
Premiums paid on extinguishment of debt and long-term debt issuance costs	**(21)**	(241)	(181)
Long-term debt repaid	**(295)**	(3,215)	(2,110)
Bonds repurchased	**(212)**	(37)	—
Issuance of preference stock	**—**	—	196
Preferred stock redeemed	**(7)**	—	—
Rate reduction notes repaid	**—**	(246)	(246)
Book overdrafts	**—**	—	(118)
Short-term debt financing – net	**1,643**	500	—
Contribution from minority shareholders	**12**	—	—
Shares purchased for stock-based compensation	**(66)**	(215)	(173)
Proceeds from stock option exercises	**30**	86	66
Excess tax benefits related to stock-based awards	**10**	45	27
Dividends to minority shareholders	**(119)**	(106)	(162)
Dividends paid	**(397)**	(378)	(352)
Net cash provided (used) by financing activities	**$ 3,210**	$ (877)	$ (703)

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

In millions — Year ended December 31,	2008	2007	2006
Cash flows from investing activities:			
Capital expenditures	**$ (2,824)**	$ (2,826)	$ (2,536)
Purchase of interest of acquired companies	**(19)**	(33)	(18)
Proceeds from sale of property and interest in projects	**113**	2	89
Proceeds from nuclear decommissioning trust sales	**3,130**	3,697	3,010
Purchases of nuclear decommissioning trusts investments and other	**(3,137)**	(3,830)	(3,150)
Proceeds from partnerships and unconsolidated subsidiaries, net of investment	**65**	42	25
Maturities and sales of short-term investments	**96**	9,953	7,128
Purchases of short-term investments	**(22)**	(9,476)	(7,474)
Restricted cash	**4**	99	13
Customer advances for construction and other investments	**(351)**	(298)	(50)
Net cash used by investing activities	**(2,945)**	(2,670)	(2,963)
Net increase (decrease) in cash and equivalents	**2,475**	(354)	(98)
Cash and equivalents, beginning of year	**1,441**	1,795	1,893
Cash and equivalents – end of year	**$ 3,916**	$ 1,441	$ 1,795

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

Consolidated Statements of Changes in Common Shareholders' Equity				Edison International
In millions	Common Stock	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Common Shareholders' Equity
Balance at December 31, 2005	$ 2,043	$ (226)	$ 4,798	$ 6,615
Net income			1,181	1,181
Other comprehensive income		324		324
SFAS No. 158 – Pension and other postretirement benefits		(30)		(30)
Tax effect		10		10
Common stock dividends declared ($1.10 per share)			(358)	(358)
Shares purchased for stock-based compensation	(33)		(136)	(169)
Proceeds from stock option exercises			66	66
Noncash stock-based compensation and other	42			42
Excess tax benefits related to stock-based awards	28			28
Balance at December 31, 2006	$ 2,080	$ 78	$ 5,551	$ 7,709
Net income			1,098	1,098
FIN 48 adoption			250	250
Other comprehensive loss		(170)		(170)
Common stock dividends declared ($1.175 per share)			(383)	(383)
Shares purchased for stock-based compensation			(216)	(216)
Proceeds from stock option exercises			86	86
Noncash stock-based compensation and other	32		(7)	25
Excess tax benefits related to stock-based awards	45			45
Change in classification of shares purchased to settle performance shares	68		(68)	—
Balance at December 31, 2007	$ 2,225	$ (92)	$ 6,311	$ 8,444
Net income			1,215	1,215
Other comprehensive income		259		259
Common stock dividends declared ($1.225 per share)			(399)	(399)
Gain on reacquired preferred stock	2			2
Shares purchased for stock-based compensation			(66)	(66)
Proceeds from stock option exercises			30	30
Noncash stock-based compensation and other	35		(13)	22
Excess tax benefits related to stock-based awards	10			10
Balance at December 31, 2008	**$ 2,272**	**$ 167**	**$ 7,078**	**$ 9,517**

Authorized common stock is 800 million shares. Outstanding common stock is 325,811,206 shares for all years presented.

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

Note 1. Summary of Significant Accounting Policies

Edison International's principal wholly owned subsidiaries include: SCE, a rate-regulated electric utility that supplies electric energy to a 50,000 square-mile area of central, coastal and southern California; and EMG, a wholly owned non-utility subsidiary; EMG is the holding company of EME and Edison Capital. 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. Edison Capital is a provider of capital and financial services. EME has domestic projects and one foreign project in Turkey; Edison Capital has domestic and foreign investments, primarily in Europe, Australia and Africa.

Basis of Presentation

The consolidated financial statements include Edison International and its wholly owned subsidiaries. Edison International consolidates subsidiaries in which it has a controlling interest and VIEs in which they are the primary beneficiary. In addition, Edison International generally uses the equity method to account for significant interests in (1) partnerships and subsidiaries in which it owns a significant or less than controlling interest and (2) VIEs in which it is not the primary beneficiary. Intercompany transactions have been eliminated, except EME's profits from energy sales to SCE, which are allowed in utility rates.

SCE's accounting policies conform to accounting principles generally accepted in the United States of America, including the accounting principles for rate-regulated enterprises, which reflect the rate-making policies of the CPUC and the FERC. SCE applies SFAS No. 71 to the portion of its operations in which regulators set rates at levels intended to recover the estimated costs of providing service, plus a return on capital. Due to timing and other differences in the collection of electric utility revenue, these principles allow an incurred cost that would otherwise be charged to expense by a nonregulated entity to be capitalized as a regulatory asset if it is probable that the cost is recoverable through future rates; and conversely these principles require creation of a regulatory liability for probable future costs collected through rates in advance of the actual costs being incurred. SCE' management continually evaluates the anticipated recovery of regulatory assets, liabilities, and electric utility revenue subject to refund and provides for allowances and/or reserves as appropriate.

Certain prior-year reclassifications have been made to conform to the December 31, 2008 consolidated financial statement presentation mostly pertaining to the adoption of FIN 39-1 and the elimination of the previously reported income statement caption "Provision for regulatory adjustment clauses — net" through classifications within relevant captions including "Operating revenue," "Purchased power," "Other operation and maintenance" and "Depreciation, decommissioning and amortization."

Financial statements prepared in conformity with accounting principles generally accepted in the United States of America require management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingency assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reported period. Actual results could differ from those estimates.

Book Overdrafts

Book overdrafts represent timing difference associated with outstanding checks in excess of cash funds that are on deposit with financial institutions. SCE's ending daily cash funds are temporarily invested in short-term investments, until required for check clearings. SCE reclassifies the amount for checks issued but not yet paid by the financial institution, from cash to book overdrafts.

Cash and Equivalents

Cash and cash equivalents as of December 31, 2008 and 2007 consisted of the following:

In millions	December 31, 2008	December 31, 2007
Cash	**$ 178**	$ 295
Money market funds	**$ 3,543**	$ 633
U.S. Treasury securities	**—**	47
U.S. government agency securities	**164**	—
Commercial paper	**30**	316
Time deposits (certificates of deposit)	**1**	150
Total cash equivalents	**$ 3,738**	$ 1,146
Total cash and cash equivalents	**$ 3,916**	$ 1,441

Cash equivalents, with the exception of money market funds, were stated at amortized cost plus accrued interest. The carrying value of cash equivalents approximates fair value due to maturities of less than three months. For further discussion of money market funds, see Note 10. Additionally, cash and equivalents of $89 million and $110 million at December 31, 2008 and 2007, respectively, are included for four projects that Edison International is consolidating under an accounting interpretation for VIEs. For a discussion of restricted cash, see "Restricted Cash."

Deferred Financing Costs

Debt premium, discount and issuance expenses are deferred and amortized (on a straight-line basis for SCE and on a basis which approximates the effective interest rate method for EMG) through interest expense over the life of each related issue. Under CPUC rate-making procedures, debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt. California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates. SCE had unamortized loss on reacquired debt of $309 million at December 31, 2008 and $331 million at December 31, 2007 reflected in "Regulatory assets" in the long-term section of the consolidated balance sheets. Edison International had unamortized debt issuance costs of $86 million at December 31, 2008 and $83 million at December 31, 2007 reflected in "Other long-term assets" on the consolidated balance sheets.

Derivative Instruments and Hedging Activities

Edison International uses derivative financial instruments to manage financial exposure on its investments and fluctuations in commodity prices, interest rates, foreign currency exchange rates, and emission and transmission rights. Edison International manages these risks in part by entering into interest rate swap, cap and lock agreements, and forward commodity transactions, including options, swaps and futures. Edison International has a power marketing and trading subsidiary that 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.

Edison International is exposed to credit loss in the event of nonperformance by counterparties. To mitigate credit risk from counterparties, master netting agreements are used whenever possible and counterparties may be required to pledge collateral depending on the creditworthiness of each counterparty and the risk associated with the transaction.

Edison International records its derivative instruments on its consolidated balance sheets at fair value as either assets or liabilities unless they meet the definition of a normal purchase or sale. The normal purchases and sales exception requires, among other things, physical delivery in quantities expected to be used or sold over a reasonable period in the normal course of business. All changes in the fair value of derivatives are recognized currently in earnings unless specific hedge criteria are met which requires Edison International to formally document, designate, and assess the effectiveness of hedge transactions. For those derivative transactions that qualify for and for which Edison International has elected hedge accounting, gains or losses from changes in the fair value of a recognized asset or liability or a firm commitment are reflected in earnings for the ineffective portion of a designated fair value hedge. For a designated hedge of the cash flows of a forecasted transaction or a foreign currency exposure, the effective portion of the gain or loss is initially recorded as a separate component of shareholders' equity under the caption "Accumulated other comprehensive income (loss)," and subsequently reclassified into earnings when the forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, is recognized currently in earnings.

Derivative assets and liabilities are shown at gross amounts on the consolidated balance sheets, except that net presentation is used when Edison International has the legal right of offset, such as multiple contracts executed with the same counterparty under master netting arrangements. In addition, derivative positions are offset against margin and cash collateral deposits in accordance with FIN No. 39-1 as discussed below in "Margin and Collateral Deposits" and "New Accounting Pronouncements." The results of derivative activities are recorded as part of cash flows from operating activities on the consolidated statements of cash flows.

To mitigate SCE's exposure to spot-market prices, the CPUC has authorized SCE to enter into power purchase contracts (including QFs), energy options, tolling arrangements and forward physical contracts. SCE records these derivative instruments on its consolidated balance sheets at fair value unless they meet the definition of a normal purchase or sale (as discussed above), or are classified as VIEs or leases. The derivative instrument fair values are marked to market at each reporting period. Any fair value changes are expected to be recovered from or refunded to customers through regulatory mechanisms and therefore SCE's fair value changes have no impact on purchased-power expense or earnings. As a result, fair value changes do not affect SCE's earnings. SCE has elected not to use hedge accounting for these transactions due to this regulatory accounting treatment.

Most of SCE's QF contracts are not required to be recorded on the consolidated balance sheets because they either do not meet the definition of a derivative or meet the normal purchases and sales exception. However, SCE purchases power from certain QFs in which the contract pricing is based on a natural gas index, but the power is not generated with natural gas. The portion of these contracts that is not eligible for the normal purchases and sales exception is recorded on the consolidated balance sheets at fair value. Unit-specific contracts (signed or modified after June 30, 2003) in which SCE takes virtually all of the output of a facility are generally considered to be leases under EITF No. 01-8.

SCE enters into interest-rate locks to mitigate interest rate risk associated with future financings. SCE expects to recover any fair value changes associated with the interest-rate locks through regulatory mechanisms. Realized and unrealized gains and losses do not affect current earnings. Realized gains/losses are amortized and recovered through interest expense over the life of the new debt.

EME's risk management and trading operations are conducted by a subsidiary. As a result of a number of industry and credit-related factors, the subsidiary has minimized its price risk management and trading activities not related to EME's power plants or investments in energy projects. To the extent it engages in trading activities, EME's trading subsidiary seeks to manage price risk and to create stability of future income by selling electricity in the forward markets and, to a lesser degree, to generate profit from price volatility of electricity and fuels by buying and selling these commodities in wholesale markets. EME generally balances forward sales and purchase contracts and manages its exposure through a value at risk analysis for trading positions and gross margin at risk analysis for hedge positions. Financial instruments that are utilized for trading purposes are measured at fair value and are included in the consolidated balance sheets 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. Fair value changes for EME's trading operations are reflected in nonutility power generation revenues. 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.

EME has nontrading derivative financial instruments arising from energy contracts related to the Illinois plants and Homer City. In assessing the fair value of its nontrading 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's unrealized gains and losses from its energy contracts are classified as part of nonutility power generation revenue.

See further information about Edison International derivative instruments in Notes 2, 7 and 10.

Dividend Restrictions

The CPUC regulates SCE's capital structure and limits the dividends it may pay Edison International. In SCE's most recent cost of capital proceeding, the CPUC sets an authorized capital structure for SCE which included a common equity component of 48%. SCE may make distributions to Edison International as long as the common equity component of SCE's capital structure remains at or above the authorized level on a 13-month weighted average basis of 48%. At December 31, 2008, SCE's 13-month weighted-average common equity component of total capitalization was 50.6% resulting in the capacity to pay $345 million in additional dividends.

Earnings Per Share

Edison International computes EPS using the two-class method, which is an earnings allocation formula that determines EPS for each class of common stock and participating security. Edison International's participating securities are stock based compensation awards payable in common shares, including stock options, performance shares and restricted stock units, which earn dividend equivalents on an equal basis with common shares. Stock options awarded during the period 2003 through 2006 received dividend equivalents. Stock options awarded prior to 2002 and after 2006 were granted without a dividend equivalent feature. As a result of meeting a performance trigger, the options granted in 1998 and 1999 began earning dividend equivalents in 2006. Performance shares awarded in 2005 – 2008 received dividend equivalents. EPS was computed as follows:

In millions **Year Ended December 31,**	**2008**	**2007**	**2006**
Basic earnings per share – continuing operations:			
Income from continuing operations	**$ 1,215**	$ 1,100	$ 1,083
Gain on redemption of preferred stock	**2**	—	—
Participating securities dividends	**(14)**	(12)	(14)
Income from continuing operations available to common shareholders	**$ 1,203**	$ 1,088	$ 1,069
Weighted average common shares outstanding	**326**	326	326
Basic earnings per share – continuing operations	**$ 3.69**	$ 3.34	$ 3.28
Diluted earnings per share – continuing operations:			
Income from continuing operations available to common shareholders	**$ 1,203**	$ 1,088	$ 1,069
Income impact of assumed conversions	**8**	12	11
Income from continuing operations available to common shareholders and assumed conversions	**$ 1,211**	$ 1,100	$ 1,080
Weighted average common shares outstanding	**326**	326	326
Incremental shares from assumed conversions	**3**	5	4
Adjusted weighted average shares – diluted	**329**	331	330
Diluted earnings per share – continuing operations	**$ 3.68**	$ 3.32	$ 3.27

Stock-based compensation awards of 3,848,546, 83,901 and 1,897,330 shares of common stock for the years ended December 31, 2008, 2007 and 2006, respectively, were not included in the computation of diluted earnings per share because the exercise price of the awards was greater than the average market price of the common shares and therefore, the effect would have been antidilutive.

Impairment of Equity Method Investments and Long-Lived Assets

Edison International 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 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 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. In accordance with SFAS No. 71, SCE's impaired assets are recorded as a regulatory asset if it is deemed probable that such amounts will be recovered from ratepayers.

Income Taxes

Edison International's eligible subsidiaries are included in Edison International's consolidated federal income tax and combined state tax returns. Edison International has tax-allocation and payment agreements with certain of its subsidiaries. For subsidiaries other than SCE, the right of a participating subsidiary to receive or make a payment and the amount and timing of tax-allocation payments are dependent on the inclusion of the subsidiary in the consolidated income tax returns of Edison International and other factors including the consolidated taxable income of Edison International and its includible subsidiaries, the amount of taxable income or net operating losses and other tax items of the participating subsidiary, as well as the other subsidiaries of Edison International. There are specific procedures regarding allocations of state taxes. Each subsidiary is eligible to receive tax-allocation payments for its tax losses or credits only at such time as Edison International and its subsidiaries generate sufficient taxable income to be able to utilize the participating subsidiary's losses in the consolidated income tax return of Edison International. Under an income tax-allocation agreement approved by the CPUC, SCE's tax liability is computed as if it filed its federal and state income tax returns on a separate return basis.

Edison International applies the asset and liability method of accounting for deferred income taxes as required by SFAS No. 109, "Accounting for Income Taxes". In accordance with FIN 48, "Accounting for Uncertainty in Income Taxes", Edison International applies judgment to assess each tax position taken on filed tax returns and tax positions expected to be taken on future returns to determine whether a tax position is more likely than not to be sustained and recognized in the financial statements. However, all temporary tax positions, whether or not the more likely than not threshold of FIN 48 is met, are recorded in the financial statements in accordance with the measurement principles of FIN 48.

As part of the process of preparing its consolidated financial statements, Edison International 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 Edison International's consolidated balance sheet. Edison International takes certain tax positions it believes are applied in accordance with tax laws. The application of these positions is subject to interpretation and audit by the IRS. As further described in Note 4, the IRS has raised issues in the audit of Edison International's tax returns with respect to certain leveraged leases of Edison Capital.

Investment tax credits associated with rate-regulated public utility property are deferred and amortized over the lives of the properties and production tax credits are recognized in the period in which they are earned.

Accounting for tax obligations requires judgments, including estimating reserves for potential adverse outcomes regarding tax positions that have been taken. Management uses judgment in determining whether the evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained on audit. Management continually evaluates its income tax exposures and provides for allowances and/or reserves as appropriate, reflected in the captions "Accrued taxes" and "Other deferred credits and long-term liabilities" on the consolidated balance sheets. Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Interest expense and penalties associated with income taxes are reflected in the caption "Income tax expense" on the consolidated statements of income.

For a further discussion of income taxes, see Note 4.

Intangible Assets

Edison International accounts for acquired intangible assets in accordance with SFAS No. 142. All of these intangible assets relate to EME. Under SFAS No. 142, acquired intangible assets with indefinite lives are not amortized, rather they are tested for impairment. Intangible assets are periodically reviewed when impairment indicators are present to assess recoverability from future operations using undiscounted future cash flows. For project development rights, the assets are subject to ongoing impairment analysis, such that if a project is no longer expected, the capitalized costs are written off.

"Other current assets" on Edison International's consolidated balance sheets includes emission allowances purchased for use by EME of $88 million and $45 million at December 31, 2008 and 2007, respectively.

"Other long-term assets" on Edison International's consolidated balance sheets include EME's project development rights, option rights, and purchased emission allowances and the total amounted to $73 million and $61 million at December 31, 2008 and 2007, respectively. Amortized intangible assets are amortized using the straight-line method over five years.

Based on the CAIR requirements, Midwest Generation purchased annual NO_X allowances under the new CAIR annual NO_X program. The CAIR, issued by the US EPA on March 10, 2005, applies to 28 eastern states and the District of Columbia and is intended to address ozone and fine particulate matter attainment issues by reducing regional NO_X and SO_2 emissions. The CAIR was challenged in court by state, environmental and industry groups. The District of Columbia Circuit Court remanded the CAIR to the US EPA until the US EPA promulgates a revised rule. The timing and substance of the revised rule are not yet clear. Depending on what happens with respect to the CAIR, and the revised SIPs developed as a consequence of the CAIR, the Illinois Plants and the Homer City facilities may be subject to additional requirements pursuant to these programs. The Illinois Plants continue to be subject to the CAIR. EME expects that compliance with the CAIR and revised or additional regulations promulgated to comply with a revised CAIR and/or other air regulatory requirements could result in increased capital expenditures and operating expenses beyond those already required by the CPS.

Inventory

Inventory is stated at the lower of cost or market, cost being determined by the weighted-average cost method for fuel, and the average cost method for materials and supplies.

Leases

Minimum lease payments under operating leases for property, plant and equipment are levelized (total minimum lease payments divided by the number of years of the lease) and recorded as rent expense over the terms of the leases. Lease payments in excess of the minimum are recorded as rent expense in the year incurred.

Capital leases are reported as long-term obligations on the consolidated balance sheets under the caption "Other deferred credits and other long-term liabilities." In accordance with SFAS No. 71, SCE's capital lease amortization expense and interest expense are reflected in the caption "Purchased power" on the consolidated statements of income.

See "Lease Commitments" in Note 6 for additional information on operating leases, capital leases and the sale-leaseback transactions.

Margin and Collateral Deposits

Margin and collateral deposits include margin requirements and cash deposited with and received from counterparties and brokers as credit support under energy contracts. The amount of margin and collateral deposits generally varies based on changes in the fair value of the related positions. See "New Accounting Pronouncements" below for a discussion of the adoption of FIN No. 39-1. In accordance with FIN No. 39-1, Edison International presents a portion of its margin and cash collateral deposits net with its derivative positions on its consolidated balance sheets. Amounts recognized for cash collateral provided to others that have been offset against net derivative liabilities totaled $123 million and $38 million at December 31, 2008 and 2007, respectively. Amounts recognized for cash collateral received from others that have been offset against net derivative assets totaled $225 million at December 31, 2008.

New Accounting Pronouncements

Accounting Pronouncements Adopted

In April 2007, the FASB issued FIN No. 39-1. This pronouncement permits companies to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. In addition, upon the adoption, companies were permitted to change their accounting policy to offset or not offset fair value amounts recognized for derivative instruments under master netting agreements. Edison International adopted FIN No. 39-1 effective January 1, 2008. The adoption resulted in netting a portion of margin and cash collateral deposits with derivative positions on Edison International's consolidated balance sheets, but had no impact on its consolidated statements of income. The consolidated balance sheet at December 31, 2007 has been retroactively restated for the change, which resulted in a decrease in net assets (margin and collateral deposits) of $38 million. The consolidated statements of cash flows for the years ended December 31, 2007 and 2006 have been retroactively restated to reflect the balance sheet changes, which had no impact on total operating cash flows from continuing operations.

In February 2007, the FASB issued SFAS No. 159, which provides an option to report eligible financial assets and liabilities at fair value, with changes in fair value recognized in earnings. Edison International adopted this pronouncement effective January 1, 2008. The adoption of this standard had no impact because Edison International did not make an optional election to report additional financial assets and liabilities at fair value.

In September 2006, the FASB issued SFAS No. 157, which clarifies the definition of fair value, establishes a framework for measuring fair value and expands the disclosures on fair value measurements. Edison International adopted SFAS No. 157 effective January 1, 2008. The adoption did not result in any retrospective adjustments to its consolidated financial statements. The accounting requirements for employers' pension and other postretirement benefit plans were effective at the end of 2008, which was the next measurement date for these benefit plans. Edison International will adopt this standard for nonrecurring nonfinancial assets and liabilities (AROs) measured or disclosed at fair value during the first quarter of 2009. Since this standard is applied prospectively, AROs existing before the adoption of the standard will not be adjusted for nonperformance risk. During 2008, Edison International did not apply SFAS No. 157 to new AROs related to its wind facilities constructed during the year. For further discussion, see Note 10.

On October 10, 2008, the FASB issued FSP SFAS No. 157-3, "Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active." This position clarifies the application of SFAS No. 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. It also reaffirms the notion of fair value as an exit price as of the measurement date. This position was effective upon issuance, including prior periods for which financial statements have not been issued. The adoption had no impact on Edison International's consolidated financial statements.

In May 2008, the FASB issued SFAS No. 162, "The Hierarchy of Generally Accepted Accounting Principles," which identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements for nongovernmental entities that are presented in conformity with GAAP. This statement transfers the GAAP hierarchy from the American Institute of Certified Public Accountants Statement on Auditing Standards No. 69, "The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles" to the FASB. SFAS No. 162, was effective on November 15, 2008. The adoption of this standard did not have an impact on Edison International's consolidated results of operations, financial position or cash flows.

In December 2008, the FASB issued FSP FAS 140-4 and FIN 46(R)-8, "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities." For asset transfers, the additional disclosure requirements primarily focus on the transferor's continuing involvement with transferred financial assets and the related risks retained. For VIEs, this position requires public enterprises to provide additional disclosures about their involvement with variable interest entities including the method for determining whether an enterprise is the primary beneficiary, the significant judgments and assumptions made and the details of any financial or other support provided to a VIE. This position was effective for reporting periods ending after December 15, 2008. The adoption did not have an impact on Edison International's consolidated financial position, results of operations or cash flows. See Note 14 for disclosures pertaining to VIEs.

In December 2008, the FASB issued FSP EITF 99-20-1, "Amendments to the Impairment guidance of EITF Issue No. 99-20," which amends the guidance for purchased beneficial interests to achieve more consistent determination of whether an other-than-temporary impairment has occurred for available-for-sale or held-to-maturity debt securities. This pronouncement was effective for reporting periods ending after December 15, 2008. Because Edison International already evaluates impairment for these securities in accordance with SFAS No. 115, the adoption did not have an impact on its consolidated financial position, results of operations or cash flows.

Accounting Pronouncements Not Yet Adopted

In December 2007, the FASB issued SFAS No. 141(R), which establishes principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date fair value. SFAS No. 141(R) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) applies prospectively to business combinations for which the acquisition date is on or after fiscal years beginning on or after January 1, 2009. Early adoption is not permitted.

In December 2007, the FASB issued SFAS No. 160, which requires an entity to present minority interest that reflects the ownership interests in subsidiaries held by parties other than the entity, within the equity section but separate from the entity's equity in the consolidated financial statements. It also requires the amount of consolidated net income attributable to the parent and to the noncontrolling interest to be clearly identified and presented on the face of the consolidated statement of income; changes in ownership interest be accounted for similarly as equity transactions; and, when a subsidiary is deconsolidated, any retained noncontrolling equity investment in the former subsidiary and the gain or loss on the deconsolidation of the subsidiary be measured at fair value. Edison International will adopt SFAS No. 160 in the first quarter of 2009. In accordance with this standard, Edison International will reclassify minority interest to a component of shareholders' equity (at December 31, 2008 this amount was $285 million).

In March 2008, the FASB issued SFAS No. 161, which requires additional disclosures related to derivative instruments, including how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS No. 161 is effective for fiscal years beginning after November 15, 2008, with early adoption permitted. Edison International will adopt SFAS No. 161 in the first quarter of 2009. Since SFAS No. 161 impacts disclosures only, the adoption of this standard will not have an impact on Edison International's consolidated results of operations, financial position or cash flows.

In April 2008, the FASB issued FSP FAS No. 142-3 which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, "Goodwill and Other Intangible Assets." The intent of the position is to improve the consistency between the useful life of a recognized intangible asset under SFAS No. 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No. 141(R) and other GAAP. Edison International will adopt FSP FAS No. 142-3 in the first quarter of 2009. The adoption of the position will not have an impact on Edison International's consolidated results of operations, financial position or cash flows.

In December 2008, the FASB issued FSP FAS 132(R)-1, "Employers" Disclosures about Postretirement Benefit Plan Assets." This position requires additional plan asset disclosures about the major categories of assets, the inputs and valuation techniques used to measure fair value, the level within the fair value hierarchy, the effect of using significant unobservable inputs (Level 3) and significant concentrations of risk. This position is effective for years ending after December 15, 2009 and, therefore, Edison International will adopt FSP FAS 132(R)-1 at year-end 2009. FSP FAS 132(R)-1 will impact disclosures only and will not have an impact on Edison International's consolidated results of operations, financial position or cash flows.

In November 2008, the FASB ratified the consensus in EITF Issue No. 08-6, "Equity Method Investment Accounting Considerations." This issue clarifies the accounting for certain transactions and impairment considerations involving equity method investments. This issue is effective prospectively beginning on January 1, 2009. Edison International expects that the adoption of this issue will not have an impact on its consolidated financial statements.

Nuclear Decommissioning

As a result of SCE's adoption of SFAS No. 143 in 2003, SCE recorded the fair value of its liability for AROs, primarily related to the decommissioning of its nuclear power facilities. At that time, SCE adjusted its nuclear decommissioning obligation, capitalized the initial costs of the ARO into a nuclear-related ARO regulatory asset, and also recorded an ARO regulatory liability as a result of timing differences between the recognition of costs recorded in accordance with SFAS No. 143 and the recovery of the related asset retirement costs through the rate-making process.

SCE plans to decommission its nuclear generating facilities by a prompt removal method authorized by the NRC. Decommissioning is expected to begin after the plants' operating licenses expire. The operating licenses currently expire in 2022 for San Onofre Units 2 and 3, and in 2024, 2025 and 2027 for the Palo Verde units. Decommissioning costs, which are recovered through nonbypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense, with a corresponding credit to the ARO regulatory liability. The earnings impact of amortization of the ARO asset included within the unamortized nuclear investment and accretion of the ARO liability, both established under SFAS No. 143, are deferred as increases to the ARO regulatory liability account, with no impact on earnings. See Note 8 for an analysis of the ARO liability.

SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. The cost of removal amounts, in excess of fair value collected for assets not legally required to be removed, are classified as regulatory liabilities.

SCE's nuclear decommissioning trusts are accounted for in accordance with SFAS No. 115, and due to regulatory recovery of SCE nuclear decommissioning expense, rate-making accounting treatment is applied to all nuclear decommissioning trust activities in accordance with SFAS No. 71. As a result, nuclear decommissioning activities do not affect SCE's earnings.

SCE's nuclear decommissioning trust investments are classified as available-for-sale. SCE has debt and equity investments for the nuclear decommissioning trust funds. Due to regulatory mechanisms, earnings and realized gains and losses (including other-than-temporary impairments) have no impact on electric utility revenue. Unrealized gains and losses on decommissioning trust funds increase or decrease the trust asset and the related regulatory asset or liability and have no impact on electric utility revenue or decommissioning expense. SCE reviews each security for other-than-temporary impairment losses on the last day of each month compared to the last day of the previous month. If the fair value on both days is less than the cost for that security, SCE will recognize a realized loss for the other-than-temporary impairment. If the fair value is greater or less than the cost for that security at the time of sale, SCE will recognize a related realized gain or loss, respectively. For a further discussion about nuclear decommissioning trusts see "Nuclear Decommissioning Commitment" in Note 6 and "Nuclear Decommissioning Trusts" in Note 10.

Planned Major Maintenance

Certain plant facilities require major maintenance on a periodic basis. These costs are expensed as incurred.

Project Development Costs

Edison International 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 Edison International. The capitalized costs are amortized over the life of operational projects or charged to expense if Edison International determines the costs to be unrecoverable.

Property and Plant

Utility Plant

Utility plant additions, including replacements and betterments, are capitalized. Such costs include direct material and labor, construction overhead, a portion of administrative and general costs capitalized at a rate authorized by the CPUC, and AFUDC. AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction. Currently, AFUDC debt and equity is capitalized during certain plant construction and reported in interest expense and other nonoperating income, respectively. AFUDC is recovered in rates through depreciation expense over the useful life of the related asset. Depreciation of utility plant is computed on a straight-line, remaining-life basis.

On November 26, 2007, the FERC issued an order granting incentives on three of SCE's largest proposed transmission projects, DPV2, Tehachapi Transmission Project ("Tehachapi"), and Rancho Vista Substation Project ("Rancho Vista"). The order permits SCE to include in rate base 100% of prudently-incurred capital expenditures during construction of all three projects. On February 29, 2008, the FERC approved SCE's revision to its Transmission Owner Tariff to collect 100% of construction work in progress (CWIP) for these projects in rate base and earn a return on equity, rather than capitalizing AFUDC. SCE implemented the

CWIP rate, subject to refund, on March 1, 2008. For further discussion, see "FERC Transmission Incentives" in Note 6.

Depreciation expense stated as a percent of average original cost of depreciable utility plant was, on a composite basis, 4.3% for 2008, 4.2% for 2007 and 4.2% for 2006.

AFUDC – equity was $54 million in 2008, $46 million in 2007 and $32 million in 2006. AFUDC – debt was $27 million in 2008, $24 million in 2007 and $18 million in 2006.

Replaced or retired property costs are charged to the accumulated provision for depreciation. Cash payments for removal costs less salvage reduce the liability for AROs.

In May 2003, the Palo Verde units returned to traditional cost-of-service ratemaking while San Onofre Units 2 and 3 returned to traditional cost-of-service ratemaking in January 2004. SCE's nuclear plant investments made prior to the return to cost-of-service ratemaking are recorded as regulatory assets on its consolidated balance sheets. Since the return to cost-of-service ratemaking, capital additions are recorded in utility plant. These classifications do not affect the rate-making treatment for these assets.

Estimated useful lives (authorized by the CPUC) and weighted-average useful lives of SCE's property, plant and equipment, are as follows:

	Estimated Useful Lives	Weighted-Average Useful Lives
Generation plant	38 years to 69 years	40 years
Distribution plant	30 years to 60 years	40 years
Transmission plant	35 years to 65 years	45 years
Other plant	5 years to 60 years	20 years

Nuclear fuel is recorded as utility plant (nuclear fuel in the fabrication and installation phase is recorded as construction in progress) in accordance with CPUC rate-making procedures. Nuclear fuel is amortized using the units of production method.

Nonutility Property

Nonutility property, including leasehold improvements and construction in progress, is capitalized at cost. Interest incurred on borrowed funds that finance construction and project development costs are also capitalized. Capitalized interest was $32 million in 2008, $24 million in 2007 and $8 million in 2006. SCE's Mountainview plant is included in nonutility property in accordance with the rate-making treatment. EME's capitalized interest is amortized over the depreciation period of the major plant and facilities for the respective project. SCE's capitalized interest is generally amortized over 30 years (the life of the purchase-power agreement under which the Mountainview plant operates).

Depreciation and amortization is primarily computed on a straight-line basis over the estimated useful lives of nonutility properties and over the shorter of the useful life or the lease term for leasehold improvements. Depreciation expense stated as a percent of average original cost of depreciable nonutility property was, on a composite basis, 3.9% for 2008, 4.0% for 2007 3.9% for 2006.

Emission allowances were acquired by EME as part of its Illinois plants and Homer City facilities acquisitions. Although these emission allowances are freely transferable, EME intends to use substantially all of the emission allowances in the normal course of its business to generate electricity. Accordingly, Edison International has classified emission allowances expected to be used by EME to generate power as part of nonutility property. These acquired emission allowances will be amortized on a straight-line basis.

Estimated useful lives for nonutility property are as follows:

Furniture and equipment	3 years to 20 years
Building, plant and equipment	3 years to 30 years
Emission allowances	25 years to 34 years
Land easements	60 years
Leasehold improvements	Shorter of life of lease or estimated useful life

Asset Retirement Obligation

Edison International accounts for its asset retirement obligations in accordance with SFAS No. 143 and FIN 47. AROs related to decommissioning of its nuclear power facilities are based on site-specific studies. The initial establishment of a nuclear-related ARO is at fair value and results in a corresponding regulatory asset. See "Nuclear Decommissioning" above for further discussion. Over time, the liability is increased for accretion each period. Edison International's conditional AROs are recorded at fair value in the period in which it is incurred if the fair value can be reasonably estimated even though uncertainty exists about the timing and/or method of settlement. When the liability is initially recorded, the cost is capitalized by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased for accretion each period, and the capitalized cost is depreciated over the useful life of the related asset. Settlement of an ARO liability, for an amount other than its recorded amount, results in a gain or loss.

Purchased Power

From January 17, 2001 to December 31, 2002, the CDWR purchased power on behalf of SCE's customers for SCE's residual net short power position (the amount of energy needed to serve SCE's customers in excess of SCE's own generation and power-purchase contracts). Additionally, the CDWR signed long-term contracts that provide power for SCE's customers. Effective January 1, 2003, SCE resumed power procurement responsibilities for its residual net short position. SCE acts as a billing agent for the CDWR power, and any power purchased by the CDWR for delivery to SCE's customers is not considered a cost to SCE.

Receivables

SCE records an allowance for uncollectible accounts, generally as determined by the average percentage of amounts written-off in prior periods. SCE assesses its customers a late fee of 0.9% per month, beginning 21 days after the bill is prepared. Inactive accounts are written off after 180 days.

Regulatory Assets and Liabilities

In accordance with SFAS No. 71, SCE records regulatory assets, which represent probable future recovery of certain costs from customers through the rate-making process, and regulatory liabilities, which represent probable future credits to customers through the rate-making process. See Note 11 for additional disclosures related to regulatory assets and liabilities.

Related Party Transactions

Specified administrative services such as payroll and employee benefit programs, performed by Edison International or SCE employees, are shared among all subsidiaries of Edison International, and the cost of these corporate support services are allocated to all subsidiaries. Costs are allocated based on one of the following formulas: percentage of time worked, relative amount of equity in investment, number of employees, or multi-factor method (operating revenue, operating expenses, total assets and number of employees). In addition, services of Edison International (or SCE) employees are sometimes directly requested by an Edison International subsidiary and these services are performed for the subsidiary's benefit. Labor and expenses of these directly requested services are specifically identified and billed at cost.

Four EME subsidiaries have 49% to 50% ownership in partnerships that sell electricity generated by their project facilities to SCE under long-term power purchase agreements with terms and pricing approved by the CPUC. Beginning March 31, 2004, Edison International consolidates these projects. See Note 14 for further information regarding VIEs.

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. EME recorded nonutility power generation revenue under these agreements of $31 million in 2008, $30 million in 2007 and $26 million in 2006. EME's accounts receivable with this affiliate totaled $10 million and $11 million at December 31, 2008 and 2007, respectively.

During the first quarter of 2008, a subsidiary of EME was awarded by SCE, through a competitive bidding process, a ten-year power sales contract with SCE for the output of a 479 MW gas-fired peaking facility located in the City of Industry, California, which is referred to as the "Walnut Creek" project. The power sales agreement was approved by the CPUC on September 18, 2008 and by the FERC on October 2, 2008. Deliveries under the power sales agreement are scheduled to commence in 2013. See Note 6 for further information.

Restricted Cash

Edison International had total restricted cash of $46 million at December 31, 2008 and $51 million at December 31, 2007. The restricted amounts included in current assets serve as collateral at Edison Capital for outstanding letters of credit. The restricted amounts included in other long-term assets are primarily to pay amounts required for lease payments and to provide collateral at EME.

Revenue Recognition

Electric utility revenue is recognized as electricity is delivered and includes amounts for services rendered but unbilled at the end of each reporting period. Rates charged to customers are based on CPUC-authorized and FERC-approved revenue requirements. CPUC rates are implemented upon final approval. FERC rates are often implemented on an interim basis at the time when the rate change is filed. Revenue collected prior to a final FERC approval decision is subject to refund. SCE's revenue requirements are based on its cost of service, referred to as base rate revenue requirement, and also provide recovery of pass-through costs under ratemaking mechanisms (balancing accounts) authorized by the CPUC. The base rate revenue requirement provides an opportunity to recover operation and maintenance expenses, capital-related carrying costs and earn an authorized rate of return. The revenue requirement for pass-through costs provides recovery of fuel and purchased-power expenses, demand-side management programs, nuclear decommissioning, public purpose programs, certain operation and maintenance expenses and depreciation expense related to certain projects. SCE recognizes electric utility revenue equal to its authorized base rate revenue requirement and equal to actual costs incurred for pass-through costs.

The CPUC-authorized decoupling revenue mechanisms allow for differences in revenue resulting from actual and forecast volumetric electricity sales to be collected from or refunded to ratepayers therefore such differences do not impact electric utility revenue. Differences between authorized operating costs included in SCE's base rate revenue requirement and actual operating costs incurred, other than pass-through costs, do not impact electric utility revenue, but have an impact on earnings.

Since January 17, 2001, power purchased by the CDWR or through the ISO for SCE's customers is not considered a cost to SCE because SCE is acting as an agent for these transactions. Furthermore, amounts billed to ($2.2 billion in 2008, $2.3 billion in 2007 and $2.5 billion in 2006) and collected from SCE's customers for these power purchases, CDWR bond-related costs (effective November 15, 2002) and a portion of direct access exit fees (effective January 1, 2003) are being remitted to the CDWR and are not recognized as electric utility revenue by SCE.

Generally, nonutility power generation revenue is recorded as electricity is generated or services are provided unless it is subject to SFAS No. 133 and does not qualify for the normal purchases and sales exception. 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 nontrading physical forward contracts on a gross basis. Consistent with EITF 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 in nonutility power generation revenue. Managed risks typically include commodity price risk associated with fuel purchases and power sales. In addition, nonutility power generation revenue includes revenue under certain long-term power sales contracts subject to EITF No. 91-6, "Revenue Recognition of Long-term Power Sales Contracts," which is 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 nonutility power generation revenue is reflected in the caption "Other deferred credits and other long-term liabilities" on the consolidated balance sheets.

Financial services and other revenue are generally derived from leveraged leases, which are recorded by recognizing income over the term of the lease so as to produce a constant rate of return based on the investment leased.

Gains and losses from sale of assets are recognized at the time of the transaction.

Sales and Use Taxes

SCE bills certain sales and use taxes levied by state or local governments to its customers. Included in these sales and use taxes are franchise fees, which SCE pays to various municipalities (based on contracts with these municipalities) in order to operate within the limits of the municipality. SCE bills these franchise fees to its customers based on a CPUC-authorized rate. These franchise fees, which are required to be paid regardless of SCE's ability to collect from the customer, are accounted for on a gross basis and reflected in electric utility revenue and other operation and maintenance expense. SCE's franchise fees billed to customers and recorded as electric utility revenue were $103 million, $104 million and $107 million for the years ended December 31, 2008, 2007 and 2006, respectively. When SCE acts as an agent, and the tax is not required to be remitted if it is not collected from the customer, the taxes are accounted for on a net basis. Amounts billed to and collected from customers for these taxes are being remitted to the taxing authorities and are not recognized as electric utility revenue.

Short-term Investments

At different times during 2008 and 2007, Edison International held various variable rate demand notes related to short-term cash management activities. The interest rate process for these securities allow for a resetting of interest rates related to changes in terms and/or credit quality, similar to cash and cash equivalents. In accordance with SFAS No. 115, if on hand at the end of a period, these notes would be classified as short-term available-for-sale investment securities and recorded at fair value. There were no outstanding notes as of December 31, 2008 and 2007. Both sales and purchases of the notes were $.1 billion, $9.5 billion and $7.5 billion for the years ended December 31, 2008, 2007 and 2006, respectively. There were no realized or unrealized gains or losses.

In addition, at December 31, 2008 and 2007, Edison International had classified all marketable debt securities as held-to-maturity and carried at amortized cost plus accrued interest which approximated their fair value. Gross unrealized holding gains and losses were not material. Edison International's short-term investments, which all mature within one year, consisted of the following:

In millions December 31,	2008	2007
Commercial paper	$ 1	$ 32
Certificates of deposit	3	41
U.S. Treasury securities	—	7
Corporate bonds	—	1
Money market funds	3	—
Total	$ 7	$ 81

Stock-Based Compensation

Stock options, performance shares, deferred stock units and, beginning in 2007, restricted stock units have been granted under Edison International's long-term incentive compensation programs. 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 option exercises, performance shares, and restricted stock units. 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. Deferred stock units granted to management are settled in cash, not stock and represent a liability. Restricted stock units are settled in common stock; however, Edison International will substitute cash awards to the extent necessary to pay tax withholding or any government levies.

On April 26, 2007, Edison International's shareholders approved a new incentive plan (the 2007 Performance Incentive Plan) that includes stock-based compensation. No additional awards were granted under Edison International's prior stock-based compensation plans on or after April 26, 2007, and all future issuances will be made under the new plan. The maximum number of shares of Edison International's common stock that may be issued or transferred pursuant to awards under the new incentive plan is 8.5 million shares, plus the number of any shares subject to awards issued under Edison International's prior plans and outstanding as of April 26, 2007, which expire, cancel or terminate without being exercised or shares being issued. As of December 31, 2008, Edison International had approximately 5.8 million shares remaining for future issuance under its stock-based compensation plan. For further discussion see "Stock-Based Compensation" in Note 5.

SFAS No. 123(R) requires companies to use the fair value accounting method for stock-based compensation. Edison International 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. The new accounting standard resulted in the recognition of expense for all stock-based compensation awards. In addition, Edison International 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 adoption of SFAS No. 123(R), Edison International presented all tax benefits of deductions resulting from the exercise of stock options as a component of operating cash flows under the caption "Other 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 $10 million, $45 million and $27 million of excess tax benefits are classified as financing cash flows in 2008, 2007 and 2006, respectively. Due to the adoption of SFAS No. 123(R), Edison International recorded a cumulative effect adjustment that increased net income by approximately $1 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.

Prior to January 1, 2006, Edison International 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 above, effective January 1, 2006, Edison International implemented a new accounting standard 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. Edison International recognizes stock-based compensation expense on a straight-line basis over the requisite service period. Because SCE capitalizes a portion of cash-based compensation and SFAS No. 123(R) requires stock-based compensation to be recorded similarly to cash-based compensation, SCE capitalizes a portion of its stock-based compensation related to both unvested awards and new awards. Edison International recognizes stock-based compensation expense for awards granted to retirement-eligible participants as follows: for stock-based awards granted prior to January 1, 2006, Edison International 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 will be 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 Edison International 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 expense would have decreased $3 million and $8 million for 2007 and 2006, respectively.

Note 2. Derivative Instruments and Hedging Activities

EME recorded net gains of approximately $171 million, $149 million and $137 million in 2008, 2007 and 2006, respectively, arising from energy trading activities, which are reflected in nonutility power generation revenue on the consolidated statements of income (including earnings from restructuring non-utility generator contracts). EME netted 4.1 million MWh of sales and purchases of physically settled, gross purchases and sales during both 2008 and 2007 and 4.3 million MWh during 2006.

EME recorded net unrealized gains (losses) arising from nontrading derivative activities of $15 million, $(35) million and $65 million in 2008, 2007 and 2006, respectively, which are reflected in nonutility power generation revenue on the consolidated statements of income.

SCE is exposed to commodity price risk associated with its purchases for additional capacity and ancillary services to meet its peak energy requirements as well as exposure to natural gas prices associated with power purchased from QFs, fuel tolling arrangements, and its own gas-fired generation, including the Mountainview plant. SCE's realized gains and losses arising from derivative instruments are reflected in purchased-power expense and are recovered through the ERRA mechanism. Unrealized gains and losses have no impact on purchased-power expense due to regulatory mechanisms. As a result, realized and unrealized gains and losses do not affect earnings, but may temporarily affect cash flows. The following is a summary of purchased-power expense:

In millions — For the year ended December 31,	2008	2007	2006
Purchased-power	**$ 3,816**	$ 3,179	$ 2,940
Realized losses on economic hedging activities – net	**60**	132	339
Energy settlements and refunds	**(31)**	(76)	(180)
Total purchased-power expense	**$ 3,845**	$ 3,235	$ 3,099

Unrealized (gains) losses on economic hedging were $638 million in 2008, $(94) million in 2007, and $237 million in 2006. Changes in realized and unrealized gains and losses on economic hedging activities were primarily due to significant decreases in forward natural gas prices in 2008 compared to 2007. Changes in realized and unrealized gains and losses on economic hedging activities in 2007 compared to 2006 were primarily due to changes in SCE's gas hedge portfolio mix as well as an increase in the natural gas futures market in 2007.

Note 3. Liabilities and Lines of Credit

Long-Term Debt

Almost all SCE properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as collateral for borrowed funds obtained from pollution-control bonds issued by government agencies. SCE used these proceeds to finance construction of pollution-control facilities. SCE has a debt covenant that requires a debt to total capitalization ratio be met. At December 31, 2008, SCE was in compliance with this debt covenant. Bondholders have limited discretion in redeeming certain pollution-control bonds, and SCE has arranged with securities dealers to remarket or purchase them if necessary.

Redemption of MEHC Senior Secured Notes

On June 25, 2007, MEHC redeemed in full its senior secured notes. As a result of the redemption, EME is no longer subject to financial and investment restrictions that were contained in the indenture pursuant to which the senior secured notes were issued.

Senior Notes Offering

In 2007, EME issued $1.2 billion of its 7.00% senior notes due 2017, $800 million of its 7.20% senior notes due 2019 and $700 million of its 7.625% senior notes due 2027. EME pays interest on the senior notes on May 15 and November 15 of each year, beginning on November 15, 2007. The net proceeds were used, together with cash on hand, to purchase substantially all of EME's outstanding 7.73% senior notes due 2009 and all of Midwest Generation's 8.75% second priority senior secured notes due 2034; repay the outstanding balance of Midwest Generation's senior secured term loan facility; and make a dividend payment of $899 million to MEHC which enabled MEHC to purchase substantially all of its 13.5% senior secured notes due 2008. Edison International recorded a total pre-tax loss of $241 million ($148 million after tax) on early extinguishment of debt in 2007.

The senior notes are redeemable by EME at any time at a price equal to 100% of the principal amount, plus accrued and unpaid interest and liquidated damages, if any, of 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.

In connection with Midwest Generation's financing activities, EME has given a first priority security interest 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, 2008. 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.

Long-term debt is:

In millions December 31,	2008	2007
First and refunding mortgage bonds:		
2009 – 2038 (4.65% to 6.0% and variable)	**$ 4,875**	$ 3,375
Pollution-control bonds:		
2015 – 2035 (2.9% to 5.55% and variable)	**1,196**	1,196
Bonds repurchased	**(249)**	(37)
Debentures and notes:		
2009 – 2053 (noninterest-bearing to 8.75%)	**5,320**	4,512
Long-term debt due within one year	**(174)**	(18)
Unamortized debt discount – net	**(18)**	(12)
Total	**$ 10,950**	$ 9,016

Note: Rates and terms as of December 31, 2008.

The interest rates on one issue of SCE's pollution control bonds insured by FGIC, totaling $249 million, were reset every 35 days through an auction process. Due to a loss of confidence in the creditworthiness of the bond insurers, there was a significant reduction in market liquidity for auction rate bonds and interest rates on these bonds increased. Consequently, SCE purchased in the secondary market $37 million of its auction rate bonds in December 2007 and the remaining $212 million during the first three months of 2008. In March 2008, SCE converted the issue to a variable rate mode and terminated the FGIC insurance policy. SCE continues to hold the bonds which remain outstanding and have not been retired or cancelled.

Long-term debt maturities and sinking-fund requirements for the next five years are: 2009 – $174 million; 2010 – $300 million; 2011 – $14 million; 2012 – $867 million and 2013 – $517 million.

Short-Term Debt

SCE short-term debt is generally used to finance fuel inventories, balancing account undercollections and general, temporary cash requirements including power purchase payments. At December 31, 2008, the outstanding short-term debt was $1.89 billion at a weighted-average interest rate of 0.67%. This short-term debt is supported by a $2.5 billion credit line. At December 31, 2007, the outstanding short-term debt was $500 million at a weighted-average interest rate of 5.29%. This short-term debt was supported by a $2.5 billion credit line. See below in "Credit Agreements."

Edison International (parent) short-term debt is generally used for liquidity purposes. At December 31, 2008, the outstanding short-term debt was $250 million at a weighted-average interest rate of 0.85%. This short-term debt is supported by a $1.5 billion credit line. Edison International parent had no short-term debt outstanding at December 31, 2007. See below in "Credit Agreements."

Credit Agreements

During 2007, EME amended its existing $500 million secured credit facility maturing on June 15, 2012, increasing the total borrowings available thereunder to $600 million, and subject to the satisfaction of conditions as set forth in the secured credit facility, EME is permitted to increase the amount available under the secured credit facility to an amount that does not exceed 15% of EME's consolidated net tangible assets, as defined in the secured credit facility. 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. At December 31, 2008, EME had borrowings outstanding of $376 million, at the applicable margin of 1.50%, classified as long-term debt and $129 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, 2008, 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 are deposited. EME is free to use these proceeds unless an event of default occurs under the credit facility.

During 2007, Midwest Generation also amended and restated its existing $500 million senior secured working capital facility. Borrowings made under this credit facility bear interest at LIBOR + 0.55%, except if average utilized commitments during a period exceed $250 million, in which case the margin increases to 0.65% which was the case at December 31, 2008. The working capital facility matures in 2012, with an option to extend for up to two years. The working capital facility contains financial covenants which require Midwest Generation to maintain a debt to capitalization ratio of no greater than 0.60 to 1. At December 31, 2008, the debt to capitalization ratio was 0.28 to 1. Midwest Generation uses its secured working capital facility to provide credit support for its hedging activities and for general working capital purposes. Midwest Generation can also support its hedging activities by granting liens to eligible hedge counterparties. As of December 31, 2008, Midwest Generation had borrowings outstanding of $475 million classified as long-term debt and $3 million of letters of credit had been utilized under the working capital facility.

In March 2008, SCE amended its $2.5 billion credit facility, extending the maturity to February 2013. The related borrowings are classified as short-term debt as it is expected to be repaid by year-end 2009. Also, in March, 2008 Edison International amended its $1.5 billion credit facility, extending the maturity to February 2013. For both SCE and Edison International, the amendment also provides four extension options which, if all exercised, and agreed to by lenders, will result in a final termination in February 2017.

During 2008, Edison International (parent) and its subsidiaries, made borrowings under their respective credit agreements.

On September 15, 2008, Lehman Brothers Holdings filed for protection under Chapter 11 of the U.S. Bankruptcy Code. A subsidiary of Lehman Brothers Holdings, Lehman Brothers Bank, FSB, is one of the lenders in SCE's and Edison International (parent) credit agreement representing a total commitment of $106 million and $74 million, respectively. Lehman Brothers Bank, FSB had funded $25 million of SCE's borrowing request during the second quarter of 2008, but declined SCE's requests during the second half of 2008 for funding of approximately $57 million. This subsidiary fully funded $12 million of Edison International (parent) borrowing request, which remains outstanding.

A subsidiary of Lehman Brothers Holdings, Lehman Commercial Paper Inc., is one of the lenders in EME's credit agreement representing a commitment of $36 million. In September 2008, Lehman Commercial Paper Inc. declined requests for funding under EME's credit agreement. Another subsidiary of Lehman Brothers Holdings, Lehman Brothers Commercial Bank, Inc., is one of the lenders in the Midwest Generation working capital facility. This subsidiary fully funded $42 million of Midwest Generation's borrowing requests, which remains outstanding. At December 31, 2008, Lehman Brothers Commercial Bank's share of the amount available to draw under the Midwest Generation working capital facility was $2 million.

The following table summarizes the status of these credit facilities at December 31, 2008:

In millions	SCE	EMG	Edison International (parent)
Commitment	$ 2,500	$ 1,100	$ 1,500
Less: Unfunded commitment from Lehman Brothers subsidiary	(81)	(36)	(62)
	2,419	1,064	1,438
Outstanding borrowings	(1,893)	(851)	(250)
Outstanding letters of credit	(141)	(132)	—
Amount available	**$ 385**	**$ 81**	**$ 1,188**

The following table summarizes the status of these credit facilities at December 31, 2007:

In millions	SCE	EMG	Edison International (parent)
Commitment	$ 2,500	$ 1,100	$ 1,500
Less: Unfunded commitment from Lehman Brothers subsidiary	—	—	—
	2,500	1,100	1,500
Outstanding borrowings	(500)	—	—
Outstanding letters of credit	(229)	(93)	—
Amount available	**$ 1,771**	**$ 1,007**	**$ 1,500**

Note 4. Income Taxes

The sources of income (loss) before income taxes are:

In millions Year ended December 31,	2008	2007	2006
Domestic	**$ 1,809**	$ 1,570	$ 1,636
Foreign	**2**	22	29
Total continuing operations	**1,811**	1,592	1,665
Discontinued operations	**5**	3	119
Accounting change	**—**	—	1
Total	**$ 1,816**	$ 1,595	$ 1,785

The components of income tax expense (benefit) by location of taxing jurisdiction are:

In millions Year ended December 31,	2008	2007	2006
Current:			
Federal	**$ 183**	$ 359	$ 652
State	**80**	95	149
Foreign	**—**	—	1
	263	454	802
Deferred:			
Federal	**307**	57	(159)
State	**26**	(19)	(61)
	333	38	(220)
Total continuing operations	**596**	492	582
Discontinued operations	**5**	5	22
Total	**$ 601**	$ 497	$ 604

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

In millions December 31,	2008	2007
Deferred tax assets:		
Property-related	**$ 556**	$ 458
Unrealized gains and losses	**77**	400
Regulatory balancing accounts	**436**	519
Decommissioning	**168**	182
Accrued charges	**108**	158
Loss and credit carryforwards	**—**	16
Pension and PBOPs	**203**	177
Other	**490**	545
Total	**$ 2,038**	$ 2,455
Deferred tax liabilities:		
Property-related	**$ 4,079**	$ 3,636
Leveraged leases	**2,313**	2,316
Capitalized software costs	**231**	128
Regulatory balancing accounts	**433**	521
Unrealized gains and losses	**70**	393
Other	**525**	490
Total	**$ 7,651**	$ 7,484
Accumulated deferred income tax liability – net	**$ 5,613**	$ 5,029
Classification of accumulated deferred income taxes – net:		
Included in total deferred credits and other liabilities	**$ 5,717**	$ 5,196
Included in current assets	**$ 104**	$ 167

The federal statutory income tax rate is reconciled to the effective tax rate from continuing operations as follows:

Year ended December 31,	2008	2007	2006
Federal statutory rate	**35.0%**	35.0%	35.0%
State tax – net of federal benefit	**4.2**	4.1	3.7
Property-related	**(3.2)**	(0.2)	0.2
Housing and production credits	**(3.1)**	(2.9)	(2.1)
Tax reserve adjustments	**0.7**	(3.5)	2.5
Resolution of state audit issue	**—**	—	(3.0)
Other	**(0.7)**	(1.6)	(1.3)
Effective tax rate	**32.9%**	30.9%	35.0%

Edison International's composite federal and state statutory income tax rate was approximately 40% (net of the federal benefit for state income taxes) for all periods presented. The lower effective tax rate of 32.9% in 2008 as compared to the statutory rate was primarily due to production and low income housing credits at EMG and software and property related flow through deductions at SCE. The lower effective tax rate of 30.9% in 2007 as compared to the statutory rate was primarily due to reductions made to the income tax reserve to reflect progress made in an administrative appeals process with the IRS related to SCE's income tax treatment of certain costs associated with environmental remediation, due to reductions made to the income tax reserve to reflect a settlement of state tax audit issues and due to production and low income housing credits at EMG. The lower effective tax rate of 35.0% in 2006 as compared to the statutory rate was primarily due to a settlement reached with the California Franchise Tax Board regarding a state apportionment issue and from low income housing and wind production tax credits at EMG. These reductions were partially offset by tax reserve accruals at SCE.

Edison International and its subsidiaries had California net operating loss carryforwards with expirations dates beginning in 2012 of $53 million and $54 million at December 31, 2008 and 2007, respectively.

Accounting for Uncertainty in Income Taxes

FIN 48 requires an enterprise 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. Edison International has filed affirmative tax claims related to tax positions, which, if accepted, could result in refunds of taxes paid or additional tax benefits for positions not reflected on filed original tax returns. FIN 48 requires the disclosure of all unrecognized tax benefits, which includes the reserves recorded for tax positions on filed tax returns and the unrecognized portion of affirmative claims.

Unrecognized Tax Benefits

The following table provides a reconciliation of unrecognized tax benefits from January 1 to December 31 and the reasons for such changes:

In millions	2008	2007
Balance at January 1	**$ 2,114**	$ 2,160
Tax positions taken during the current year		
Increases	**118**	69
Decreases	**—**	—
Tax positions taken during a prior year		
Increases	**162**	125
Decreases	**(157)**	(230)
Decreases for settlements during the period	**—**	(10)
Reductions for lapses of applicable statute of limitations	**—**	—
Balance at December 31	**$ 2,237**	$ 2,114

The unrecognized tax benefits in the table above reflect affirmative claims related to timing differences of $1.5 billion and $1.6 billion at December 31, 2008 and 2007, respectively, that have been claimed on amended tax returns, but have not met the recognition threshold pursuant to FIN 48 and have been denied by the IRS as part of their examinations. These affirmative claims remain unpaid by the IRS and no receivable has been recorded. Edison International has vigorously defended these affirmative claims in IRS administrative appeals proceedings and these claims are included in the ongoing Global Settlement negotiations.

It is reasonably possible that Edison International could resolve, as part of the Global Settlement, or otherwise, with the IRS, all or a portion of the unrecognized tax benefits through tax year 2002 within the next 12 months, which could reduce unrecognized tax benefits by up to $1.4 billion.

The total amount of unrecognized tax benefits as of December 31, 2008 and 2007, respectively, that if recognized, would have an effective tax rate impact is $210 million and $206 million, respectively.

Accrued Interest and Penalties

The total amounts of accrued interest and penalties related to Edison International's income tax reserve were $200 million and $162 million as of December 31, 2008 and 2007, respectively. The after-tax interest expense (income) recognized and included in income tax expense was $23 million and $(12) million in 2008 and 2007, respectively.

California Apportionment

In December 2006, Edison International reached a settlement with the California Franchise Tax Board regarding the sourcing of gross receipts from the sale of electric services for California state tax apportionment purposes for tax years 1981 to 2004. In 2006, Edison International recorded a $49 million benefit related to a tax reserve adjustment as a result of this settlement. In the FIN 48 adoption, a $54 million benefit was recorded related to this same issue. In addition, Edison International received a net cash refund of approximately $52 million in April 2007.

Tax Positions being Addressed as Part of Active Examinations, Administrative Appeals and the Global Settlement

In the normal course, Edison International's federal income tax returns are examined by the IRS and Edison International challenges deficiency adjustments, asserted as part of an examination, to the Administrative Appeals branch of the IRS (IRS Appeals) to the extent Edison International believes its tax reporting positions properly complied with the relevant tax law and that the IRS' basis for making such adjustments lacks merit.

Edison International has challenged certain IRS deficiency adjustments, asserted as part of the examination of tax years 1994 – 1999 with IRS Appeals. Edison International has also been under active IRS examination for tax years 2000 – 2002 and during the third quarter of 2008, the IRS commenced an examination of tax years 2003 – 2006. In addition, the statute of limitations remains open for tax years 1986 – 1993, which has allowed Edison International to file certain affirmative claims related to these tax years.

Most of the tax positions that Edison International is addressing with IRS Appeals relate to the timing of when deductions for federal income tax purposes are allowed to be reflected on filed income tax returns and, as such, any deductions not sustained would be deductible on future tax returns filed by Edison International. However, any penalties and interest associated with disallowed deductions would result in a permanent cost. Edison International has also filed affirmative claims with respect to certain tax years 1986 through 2005 with the IRS and state tax authorities. At this time, there has not been a final determination of these affirmative claims by the IRS or state tax authorities. Benefits, if any, associated with these affirmative claims would be recorded in accordance with FIN 48 which provides that recognition would occur at the earlier of when Edison International would make an assessment that the affirmative claim position has a more likely than not probability of being sustained or when a settlement of the affirmative claim is consummated with the tax authority. Certain of these affirmative claims have been recognized as part of the implementation of FIN 48.

Edison International has been engaged in settlement negotiations with the IRS to reach a Global Settlement described below of all unresolved tax disputes and affirmative claims for tax years 1986 – 2002 and to resolve cross-border, leveraged-lease issues in their entirety.

In addition to the IRS audits, Edison International's California and other state income tax returns are, in the normal course, subjected to examination by the California Franchise Tax Board and the other state tax authorities. The Franchise Tax Board has substantially completed its examination of all tax years through 2002 and is currently awaiting resolution of the IRS audit before finalizing the audit for these tax years. Edison International is currently under active examination for tax years 2003 – 2004 and remains subject to examination by the California Franchise Tax Board for tax years 2005 and forward.

Edison International filed amended California Franchise tax returns for tax years 1997 – 2002 to mitigate the possible imposition of California non-economic substance penalty provisions on transactions that may be considered as Listed or substantially similar to Listed Transactions described in an IRS notice that was published in 2001. These transactions include certain Edison Capital leveraged-lease transactions and an SCE subsidiary contingent liability company transaction, described below. Edison International filed these amended returns under protest retaining its appeal rights.

The issues discussed below are included in the ongoing IRS examination and appeals process and are included in the scope of issues being addressed as part of the Global Settlement process.

Balancing Account Over-Collections

In response to an affirmative claim filed by Edison International related to balancing account over-collections, the IRS issued a Notice of Proposed Adjustment in July 2007 as part of the ongoing IRS examinations and administrative appeals processes. The tax years to which adjustments are made pursuant to this Notice of Proposed Adjustment are included in the scope of the Global Settlement process. The cash and earnings impacts of this position are dependent on the ultimate settlement of all open tax issues, including this issue, in these tax years. Edison International expects that resolution of this issue could potentially increase earnings and cash flows within the range of $70 million to $80 million and $300 million to $350 million, respectively.

Contingent Liability Company

The IRS has asserted tax deficiencies and penalties of $53 million and $22 million, respectively, for tax years 1997 – 1999 with respect to a transaction entered into by a former SCE subsidiary which the IRS has asserted to be substantially similar to a Listed Transaction described by the IRS as a contingent liability company.

Cross-Border Lease Transactions

As part of a nationwide challenge of cross border lease transactions, the IRS has asserted deficiencies related to Edison International's deferral of income taxes associated with certain of its cross-border, leveraged leases.

These asserted deficiencies relate to Edison Capital's income tax treatment of both its foreign power plant and electric locomotive sale/leaseback transactions entered into in 1993 and 1994 (Replacement Leases, which the IRS refers to as sale-in/lease-out or SILOs) and its foreign power plants and electric transmission system lease/leaseback transactions entered into in 1997 and 1998 (Lease/Leaseback, which the IRS refers to as lease-in/lease-out or LILOs). For tax years 1994 – 1999, Edison International is challenging the asserted deficiencies in ongoing IRS appeals proceedings and is seeking to resolve the asserted deficiencies as part of the Global Settlement process.

In 1999, Edison Capital entered into a lease/service contract transaction involving a foreign telecommunication system (Service Contract, which the IRS refers to as a SILO). As part of an ongoing examination of 2000 – 2002, the IRS examination branch has been reviewing Edison International's income tax treatment of this Service Contract. The income tax treatment of the Service Contract is included in the Global Settlement process for all tax years.

The following table summarizes estimated federal and state income taxes deferred from these leases as of December 31, 2008. Repayment of the entire amount of the deferred income taxes, as provided in the table below, would be accelerated if Edison International and the IRS were unable to reach a settlement and the IRS position were sustained in litigation:

In millions	Tax Years Under Appeal 1994 – 1999	Tax Years Under Audit 2000 – 2006	Unaudited Tax Years 2007 – 2008	Total
Replacement Leases (SILO)	$ 44	$ 42	$ 7	$ 93
Lease/Leaseback (LILO)	563	572	(32)	1,103
Service Contract (SILO)	—	326	110	436
Total	**$ 607**	**$ 940**	**$ 85**	**$ 1,632**

As of December 31, 2008, the after-tax interest on the proposed tax adjustments is estimated to be approximately $643 million. The IRS has also asserted a 20% penalty on any sustained adjustment (other than with respect to the Service Contract).

Edison International believes that its maximum earnings exposure related to these leases, measured as of December 31, 2008, is approximately $1.3 billion after taxes, calculated by reclassifying deferred income taxes to current, re-computing the cumulative earnings under the leases in accordance with lease accounting rules (FASB Staff Position FAS 13-2), and recording interest related to the current income tax liability. Interest will continue to accrue until the alleged deficiency is resolved. This exposure does not include IRS asserted penalties of 20%, as Edison International does not believe that even if the tax return positions taken by Edison Capital are successfully challenged by the IRS that these penalties would be sustained. The current and future earnings and cash positions of SCE and EME are virtually unaffected by these leases.

During the second quarter of 2008, there were court decisions involving income taxation of cross-border leveraged leases that were adverse to the taxpayers involved. These developments underscore the uncertain nature of tax conclusions in this area. Despite these developments, Edison International believes it properly reported these transactions based on applicable statutes, regulations and case law and, in the absence of any settlement with the IRS, will continue to vigorously defend its tax treatment of these leases. Edison International will continue to monitor and evaluate its lease transactions with respect to future events. Future adverse developments, including further adverse case law developments, could change Edison International's current conclusions.

Global Settlement

As previously disclosed, Edison International has negotiated the material terms of a Global Settlement with the IRS which, if consummated, would resolve cross-border, leveraged lease issues in their entirety and all other outstanding tax disputes for open tax years 1986 through 2002, including certain affirmative claims for unrecognized tax benefits. Consummation of the Global Settlement is subject to review by the Staff of the Joint Committee on Taxation, a committee of the United States Congress (the "Joint Committee"). The IRS submitted the pertinent terms of the Global Settlement to the Joint Committee during the fourth quarter of 2008, and its response is currently pending. Edison International cannot predict the timing of when the Joint Committee will complete its review. Moreover, Edison International cannot predict whether the Joint Committee will concur with the settlement terms negotiated by the IRS for the Global Settlement issues and whether any non-concurrence would result in the IRS proposing different settlement terms. Failure to consummate the Global Settlement and to be successful in any ensuing litigation over issues included in the Global Settlement process, including asserted deficiencies regarding the cross-border leases, could have an adverse affect on Edison International.

In the first quarter of 2009, Edison International terminated two of the six cross-border leveraged leases. The timing for terminating the remaining cross-border leases is uncertain and could occur prior to the Joint Committee completing its work or otherwise prior to consummation of the settlement. Edison Capital and its subsidiaries have reached an agreement based on executed term sheets with all of the counterparties to its SILOs and LILOs which contemplate termination of the leases subject to a final settlement agreement with the IRS. Certain of these agreements are not binding on Edison Capital or the counterparties until such termination. Upon termination of the leases, the lessees would be required to make termination payments from certain collateral deposits associated with the leases, and Edison International would no longer recognize earnings from such leases. In 2008 income from leveraged leases was $28 million. If all settlements included in the Global Settlement process were ultimately concluded consistent with the terms submitted to the Joint Committee, Edison International would expect that the settlement of the disputed lease issues and the resolution of the above-mentioned affirmative claims would result in a portion of any charge initially recorded upon termination of the leases being offset and/or reduced, and the net after-tax earnings charge that would remain is currently expected to be less than half of the maximum after-tax earnings exposure, calculated as of December 31, 2008, discussed above. Furthermore, if all settlements included in the Global Settlement discussions were ultimately concluded consistent with the terms submitted to the Joint Committee, the net cash impact upon Edison International as a whole of the Global Settlement and lease terminations would be positive over time. Termination of the leases prior to consummation of the settlements would result in Edison International initially recording an after-tax charge to earnings currently estimated to be at least $650 million (and potentially up to the maximum earnings exposure indicated above), which would be reduced and/or offset upon completion of the Global Settlement.

To the extent that Edison International is unable to consummate the Global Settlement or other acceptable settlement with the IRS, Edison International will continue to vigorously defend its tax treatment of the leases and is prepared to take legal action. If Edison International were to commence litigation in certain forums, it would need to make payments of the disputed taxes, along with interest and any penalties asserted by the IRS, and thereafter pursue refunds. In the United States Tax Court, no upfront payment would be required. In 2006, Edison International paid $111 million of the taxes, interest and penalties for tax year 1999 followed by a refund claim for the same amount. The IRS did not act on this refund claim within the statutory period, which provides Edison International with the option of being able to take legal action to assert its refund claim. To the extent an acceptable settlement is not reached with the IRS, Edison International, based on its preference for litigation forum, may file refund claims for any taxes, interest and penalties paid for tax years related to these leases. However, Edison International has not decided whether and to what extent it would make additional payments related to later tax years to fund its right to litigate in certain forums should the Global Settlement, or another settlement, not be consummated.

If and when Edison International and the IRS consummate a settlement, Edison International will file amended tax returns with the Franchise Tax Board and other state administrative agencies, for those states in which Edison International has an income tax filing requirement, to reflect the respective state income tax impact of the settlement terms.

Resolution of Federal and State Income Tax Issues Being Addressed in Ongoing Examinations, Administrative Appeals and the Global Settlement

Edison International continues its efforts to resolve open tax issues through tax year 2002 as part of the Global Settlement. Although the timing for resolving these open tax positions is uncertain, it is reasonably possible that all or a significant portion of these open tax issues through tax year 2002 could be resolved within the next 12 months.

Note 5. Compensation and Benefit Plans

Employee Savings Plan

Edison International has a 401(k) defined contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of $80 million in 2008, $73 million in 2007 and $69 million in 2006.

Pension Plans and Postretirement Benefits Other Than Pensions

SFAS No. 158 requires companies to recognize the overfunded or underfunded status of defined benefit pension and other postretirement plans as assets and liabilities in the balance sheet; the assets and/or liabilities are normally offset through other comprehensive income (loss). Edison International adopted SFAS No. 158 as of December 31, 2006. In accordance with SFAS No. 71, Edison International recorded regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for its postretirement benefit plans that are recoverable in utility rates.

Pension Plans

Noncontributory defined benefit pension plans (some with cash balance features) cover most employees meeting minimum service requirements. SCE recognizes pension expense for its nonexecutive plan as calculated by the actuarial method used for ratemaking. The expected contributions (all by the employer) are approximately $51 million for the year ending December 31, 2009. The fair value of plan assets is determined primarily by quoted market prices.

Volatile market conditions have affected the value of Edison International's trusts established to fund its future long-term pension benefits. The market value of the investments (reflecting investment returns, contributions and benefit payments) within the plan trusts declined 35% during 2008. This reduction in the value of plan assets resulted in a change in the pension plan funding status from overfunded to underfunded and will also result in increased future expense and increased future contributions. Changes in the plan's funded status affect the assets and liabilities recorded on the balance sheet in accordance with SFAS No. 158. Due to SCE's regulatory recovery treatment, the recognition of the funded status is offset by regulatory liabilities and assets. In the 2009 GRC, SCE requested recovery of and continued balancing account treatment for amounts contributed to these trusts. The Pension Protection Act of 2006 establishes new minimum funding standards and restricts plans underfunded by more than 20% from providing lump sum distributions and adopting amendments that increase plan liabilities.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2008	2007
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	**$ 3,355**	$ 3,410
Service cost	**120**	117
Interest cost	**199**	185
Amendments	**—**	(5)
Actuarial loss (gain)	**3**	(97)
Special termination benefits	**—**	2
Benefits paid	**(238)**	(257)
Projected benefit obligation at end of year	**$ 3,439**	$ 3,355
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 3,597**	$ 3,458
Actual return (loss) on plan assets	**(1,105)**	294
Employer contributions	**86**	102
Benefits paid	**(238)**	(257)
Fair value of plan assets at end of year	**$ 2,340**	$ 3,597
Funded status at end of year	**$ (1,099)**	$ 242
Amounts recognized in the consolidated balance sheets consist of :		
Long-term assets	**$ —**	$ 430
Current liabilities	**(9)**	(8)
Long-term liabilities	**(1,090)**	(180)
	$ (1,099)	$ 242
Amounts recognized in accumulated other comprehensive loss consist of:		
Prior service cost	**$ 2**	$ 3
Net loss	**91**	37
	$ 93	$ 40
Amounts recognized as a regulatory asset (liability):		
Prior service cost	**$ 33**	$ 49
Net loss (gain)	**951**	(357)
	$ 984	$ 308
Total not yet recognized as expense	**$ 1,077**	$ 348
Accumulated benefit obligation at end of year	**$ 3,129**	$ 2,992
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	**$ 3,439**	$ 276
Accumulated benefit obligation	**$ 3,129**	$ 232
Fair value of plan assets	**$ 2,340**	$ 88
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	6.25%	6.25%
Rate of compensation increase	5.0%	5.0%

Expense components and other amounts recognized in other comprehensive income:

Expense components are:

In millions Year ended December 31,	2008	2007	2006
Service cost	**$ 120**	$ 117	$ 118
Interest cost	**199**	185	181
Expected return on plan assets	**(259)**	(245)	(232)
Special termination benefits	**—**	2	8
Amortization of prior service cost	**17**	17	16
Amortization of net loss	**5**	6	6
Expense under accounting standards	**$ 82**	$ 82	$ 97
Regulatory adjustment – deferred	**(4)**	(3)	(10)
Total expense recognized	**$ 78**	$ 79	$ 87

Other changes in plan assets and benefit obligations recognized in other comprehensive income:

In millions Year ended December 31,	2008	2007
Net loss	**$ 59**	$ —
Prior service cost	**—**	—
Amortization of prior service cost	**(1)**	(1)
Amortization of net loss	**(5)**	(6)
Total recognized in other comprehensive (income) loss	**$ 53**	$ (7)
Total recognized in expense and other comprehensive income	**$ 131**	$ 72

Effective with the adoption of SFAS No. 158, as of December 31, 2006, and in accordance with SFAS No. 71, Edison International records regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for its postretirement benefit plans that are recoverable in utility rates. The estimated amortization amounts for 2009 are $17 million for prior service cost and $57 million for net loss including $1 million and $9 million respectively, reclassified from other comprehensive income.

Due to the Mohave shutdown, SCE has incurred costs for special termination benefits.

The following are weighted-average assumptions used to determine expense:

Year ended December 31,	2008	2007	2006
Discount rate	**6.25%**	5.75%	5.5%
Rate of compensation increase	**5.0%**	5.0%	5.0%
Expected long-term return on plan assets	**7.5%**	7.5%	7.5%

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

In millions Year ended December 31,	
2009	$ 291
2010	$ 297
2011	$ 312
2012	$ 319
2013	$ 316
2014 – 2018	$ 1,576

The following are asset allocations by investment category:

	Target for 2009	December 31, 2008	December 31, 2007
United States equities	39%	**41%**	47%
Non-United States equities	17%	**22%**	25%
Private equities	4%	**4%**	2%
Fixed income	40%	**33%**	26%

Postretirement Benefits Other Than Pensions

Most nonunion 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. The expected contributions (all by the employer) to the PBOP trust are $128 million for the year ending December 31, 2009. The fair value of plan assets is determined primarily by quoted market prices.

Volatile market conditions have affected the value of Edison International's trusts established to fund its future other postretirement benefits. The market value of the investments (reflecting investment returns, contributions and benefit payments) within the plan trust declined 33% during 2008. This reduction in the value of plan assets resulted in an increase in the plan underfunded status and will also result in increased future expense and increased future contributions. Changes in the plan's funded status affect the assets and liabilities recorded on the balance sheet in accordance with SFAS No. 158. Due to SCE's regulatory recovery treatment, the recognition of the funded status is offset by regulatory liabilities and assets. In the 2009 GRC, SCE requested recovery of and continued balancing account treatment for amounts contributed to this trust.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2008	2007
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,271**	$ 2,260
Service cost	**41**	45
Interest cost	**136**	130
Amendments	**3**	7
Actuarial gain	**(20)**	(77)
Special termination benefits	**—**	1
Plan participants' contributions	**11**	9
Medicare Part D subsidy received	**5**	4
Benefits paid	**(96)**	(108)
Benefit obligation at end of year	**$ 2,351**	$ 2,271
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 1,816**	$ 1,743
Actual return (loss) on assets	**(557)**	117
Employer contributions	**33**	51
Plan participants' contributions	**11**	9
Medicare Part D subsidy received	**5**	4
Benefits paid	**(96)**	(108)
Fair value of plan assets at end of year	**$ 1,212**	$ 1,816
Funded status at end of year	**$ (1,139)**	$ (455)
Amounts recognized in the consolidated balance sheets consist of:		
Current liabilities	**$ (20)**	$ (20)
Long-term liabilities	**(1,119)**	(435)
	$ (1,139)	$ (455)
Amounts recognized in accumulated other comprehensive loss (income) consist of:		
Prior service cost (credit)	**$ (4)**	$ (9)
Net loss	**24**	20
	$ 20	$ 11
Amounts recognized as a regulatory asset (liability):		
Prior service cost (credit)	**$ (178)**	$ (206)
Net loss	**1,076**	437
	$ 898	$ 231
Total not yet recognized as expense	**$ 918**	$ 242
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	**6.25%**	6.25%
Assumed health care cost trend rates:		
Rate assumed for following year	**8.75%**	9.25%
Ultimate rate	**5.5%**	5.0%
Year ultimate rate reached	**2016**	2015

Expense components and other amounts recognized in other comprehensive income:

Expense components are:

In millions Year ended December 31,	2008	2007	2006
Service cost	**$ 41**	$ 45	$ 45
Interest cost	**136**	130	120
Expected return on plan assets	**(123)**	(118)	(105)
Special termination benefits	**—**	1	4
Amortization of prior service cost (credit)	**(31)**	(31)	(31)
Amortization of net loss	**16**	30	43
Total expense	**$ 39**	$ 57	$ 76

Other changes in plan assets and benefit obligations recognized in other comprehensive income:

In millions Year ended December 31,	2008	2007
Net loss	**$ 6**	$ 3
Prior service cost	**3**	—
Amortization of prior service cost (credit)	**2**	2
Amortization of net loss	**(2)**	(2)
Total recognized in other comprehensive income	**$ 9**	$ 3
Total recognized in expense and other comprehensive income	**$ 48**	$ 60

Effective with the adoption of SFAS No. 158, as of December 31, 2006, and in accordance with SFAS No. 71, Edison International records regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for its postretirement benefit plans that are recoverable in utility rates. The estimated amortization amounts for 2009 are $(30) million for prior service cost (credit) and $63 million for net loss including $(2) million and $1 million respectively, reclassified from other comprehensive income.

Due to the Mohave shutdown, SCE has incurred costs for special termination benefits.

The following are weighted-average assumptions used to determine expense:

Year ended December 31,	2008	2007	2006
Discount rate	**6.25%**	5.75%	5.5%
Expected long-term return on plan assets	**7.0%**	7.0%	7.0%
Assumed health care cost trend rates:			
Current year	**9.25%**	9.25%	10.25%
Ultimate rate	**5.0%**	5.0%	5.0%
Year ultimate rate reached	**2015**	2015	2011

Increasing the health care cost trend rate by one percentage point would increase the accumulated benefit obligation as of December 31, 2008 by $263 million and annual aggregate service and interest costs by $18 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated benefit obligation as of December 31, 2008 by $236 million and annual aggregate service and interest costs by $16 million.

The following are benefit payments expected to be paid:

In millions	Year ending December 31,	Before Subsidy*	Net
2009		$ 104	$ 99
2010		$ 115	$ 109
2011		$ 125	$ 119
2012		$ 135	$ 127
2013		$ 144	$ 136
2014 – 2018		$ 857	$ 801

* Medicare Part D prescription drug benefits

The following are asset allocations by investment category:

	Target for 2009	December 31, 2008	2007
United States equities	45%	58%	62%
Non-United States equities	17%	11%	14%
Private equities	1%	—	—
Fixed income	37%	31%	24%

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. As a result of the significant increase in global financial markets volatility, during 2008 and in early 2009, the trusts' investment committee approved interim changes in target asset allocations. Edison International employs multiple investment management firms. Investment managers within each asset class cover a range of investment styles and approaches. Risk is managed through diversification among multiple asset classes, managers, styles and securities. Plan, asset class and individual manager performance is measured against targets. Edison International also monitors the stability of its investments managers' organizations.

Allowable investment types include:

United States Equities: Common and preferred stocks of large, medium, and small companies which are predominantly United States-based.

Non-United States Equities: 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 nonpublicly 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 positions may be held in debt securities that are below investment grade.

Permitted ranges around asset class portfolio weights are plus or minus 3%. 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 plan's 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

The overall expected long term rate of return on assets assumption is based on the long-term target asset allocation for plan assets and capital markets return forecasts for asset classes employed. A portion of the PBOP 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

Capital markets return forecasts are based on a long-term equilibrium forecast from an independent firm, as well as a separate analysis of expected equilibrium returns. The independent firm uses its research and judgment to determine long-term equilibrium forecasts. A core set of macroeconomic variables is used including real GDP growth, personal consumption expenditures, the federal funds target rate, dividend yield, and the Treasury yield curve. Fixed income, equity and private equity returns are determined from these factors. In addition, a separate analysis of equilibrium returns is made. 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 and projected 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 includes a 3% premium over the estimated total return of intermediate United States government bonds. 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

Total stock-based compensation expense, net of amounts capitalized (reflected in the caption "Other operation and maintenance" on the consolidated statements of income) was $31 million, $42 million and $52 million for 2008, 2007 and 2006, respectively. The income tax benefit recognized in the consolidated statements of income was $12 million, $17 million and $21 million for 2008, 2007 and 2006, respectively. Total stock-based compensation cost capitalized was $3 million, $4 million and $6 million for 2008, 2007 and 2006, respectively.

Stock Options

Under various plans, Edison International has granted stock options at exercise prices equal to the average of the high and low price, and beginning in 2007, at the closing price at the grant date. Edison International may grant stock options 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 "Stock-Based Compensation" in Note 1. Stock-based compensation expense, net of amounts capitalized, associated with stock options was $25 million, $25 million and $37 million for 2008, 2007 and 2006, respectively. See "Stock-Based Compensation" in Note 1 for further discussion.

Stock options granted in 2003 through 2006 accrue dividend equivalents for the first five years of the option term. Stock options granted in 2007 and 2008 have no dividend equivalent rights. 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 grant date using the Black-Scholes option-pricing model. The Black-Scholes option-pricing model requires various assumptions noted in the following table.

Year ended December 31,	2008	2007	2006
Expected terms (in years)	**7.4**	7.5	9 to 10
Risk-free interest rate	**2.6% – 3.8%**	4.6% – 4.8%	4.3% – 4.7%
Expected dividend yield	**2.3% – 3.9%**	2.1% – 2.4%	2.3% – 2.8%
Weighted-average expected dividend yield	**2.6%**	2.4%	2.4%
Expected volatility	**17% – 19%**	16% – 17%	16% – 17%
Weighted-average volatility	**17.6%**	16.5%	16.3%

The expected term represents the period of time for which the options are expected to be outstanding and is primarily based on historical exercise and post-vesting cancellation experience and stock price history. The risk-free interest rate for periods within the contractual life of the option is based on a zero coupon U.S. Treasury issued STRIPS (separate trading of registered interest and principal of securities) whose maturity equals the option's expected term on the measurement date. In 2006 – 2008, expected volatility is based on the historical volatility of Edison International's common stock for the most recent 36 months.

The following is a summary of the status of Edison International stock options:

		Weighted-Average		
	Stock Options	Exercise Price	Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding at December 31, 2007	12,105,642	$ 30.55		
Granted	2,843,308	$ 48.43		
Expired	(13,905)	$ 46.65		
Forfeited	(343,423)	$ 48.43		
Exercised	(1,149,787)	$ 26.14		
Outstanding at December 31, 2008	**13,441,835**	**$ 34.22**	**6.27**	
Vested and expected to vest at December 31, 2008	13,045,138	$ 33.87	6.20	$ 156,019,850
Exercisable at December 31, 2008	**7,988,722**	**$ 26.79**	**5.08**	**$ 152,105,267**

Stock options granted in 2008 and 2007 do not accrue dividend equivalents except for options granted to Edison International's Board of Directors.

The weighted-average grant-date fair value of options granted during 2008, 2007 and 2006 was $9.70, $11.44 and $14.42, respectively. The total intrinsic value of options exercised during 2008, 2007 and 2006 was $24 million, $109 million, and $70 million, respectively. At December 31, 2008, there was $29 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 2008, 2007 and 2006 was $24 million, $27 million and $45 million, respectively.

The amount of cash used to settle stock options exercised was $55 million, $195 million and $136 million for 2008, 2007 and 2006, respectively. Cash received from options exercised for 2008, 2007 and 2006 was $30 million, $86 million and $66 million, respectively. The estimated tax benefit from options exercised for 2008, 2007 and 2006 was $10 million, $43 million and $27 million, respectively.

Performance Shares

A target number of contingent performance shares were awarded to executives in March 2006, March 2007 and March 2008 and vest at the end of December 2008, 2009 and 2010, respectively. Performance shares awarded in 2005 and 2006 accrue dividend equivalents which accumulate without interest and will be payable in cash following the end of the performance period when the performance shares are paid. Edison International has discretion to pay certain dividend equivalents in Edison International common stock. Performance shares awarded in 2007 and 2008 contain dividend equivalent reinvestment rights. An additional number of target contingent performance shares will be credited based on dividends on Edison International common stock for which the ex-dividend date falls within the performance period. 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 "Stock-Based Compensation" in Note 1. Stock-based compensation expense (benefit), net of amounts capitalized, associated with performance shares was $(4) million, $12 million and $15 million for 2008, 2007 and 2006, respectively. The amount of cash used to settle performance shares classified as equity awards was $10 million, $20 million and $37 million for 2008, 2007 and 2006, respectively. In 2007 we changed the classification of the cash paid for the settlements of performance shares from common stock to retained earnings to conform with the classification for settlements of stock option exercises.

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 zero coupon U.S. Treasury issued STRIPS (separate trading of registered interest and principal of securities) and is used as a 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 2008, 2007 and 2006 performance shares classified as share-based equity awards was 3.9%, 4.8% and 4.1%, respectively. Edison International's expected volatility used to determine the grant date fair values for the 2008, 2007 and 2006 performance shares classified as share-based equity awards was 17.4%, 16.5% and 16.2%, 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, 2008 was 0.8% and 19.2%, respectively, for 2008 performance shares. The risk-free interest rate and expected volatility rate used to determine the fair value as of December 31, 2007 was 4.3% and 17.1%, respectively, for 2007 performance shares.

The total intrinsic value of performance shares settled during 2008, 2007 and 2006 was $22 million, $44 million and $73 million, respectively, which included cash paid to settle the performance shares classified as liability awards for 2008, 2007 and 2006 of $8 million, $14 million and $24 million, respectively. At December 31, 2008, there was $4 million (based on the December 31, 2008 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 approximately two years. The fair value of performance shares vested during 2008, 2007 and 2006 was $4 million, $17 million and $27 million, respectively.

The following is a summary of the status of Edison International nonvested performance shares classified as equity awards:

	Performance Shares	Weighted-Average Grant-Date Fair Value
Nonvested at December 31, 2007	149,499	$ 55.01
Granted	117,075	$ 45.53
Forfeited	(91,397)	$ 53.53
Paid out	—	$ —
Nonvested at December 31, 2008	**175,177**	**$ 49.45**

The weighted-average grant-date fair value of performance shares classified as equity awards granted during 2008, 2007 and 2006 was $45.53, $57.55 and $52.90, respectively.

The following is a summary of the status of Edison International nonvested performance shares classified as liability awards (the current portion is reflected in the caption "Other current liabilities" and the long-term portion is reflected in "Accumulated provision for pensions and benefits" on the consolidated balance sheets):

	Performance Shares	Weighted-Average Fair Value
Nonvested at December 31, 2007	149,680	
Granted	116,894	
Forfeited	(91,397)	
Paid out	—	
Nonvested at December 31, 2008	**175,177**	**$ 3.74**

Note 6. Commitments and Contingencies

Lease Commitments

In accordance with EITF No. 01-8, power contracts signed or modified after June 30, 2003, need to be assessed for lease accounting requirements. Unit specific contracts in which SCE takes virtually all of the output of a facility are generally considered to be leases. As of December 31, 2005, SCE had six power contracts classified as operating leases. In 2006, SCE modified 62 power contracts. No contracts were modified in 2007 and 2008. The modifications to the contracts resulted in a change to the contractual terms of the contracts at which time SCE reassessed these power contracts under EITF No. 01-8 and determined that the contracts are leases and subsequently met the requirements for operating leases under SFAS No. 13. These power contracts had previously been grandfathered relative to EITF No. 01-8 and did not meet the normal purchases and sales exception. As a result, these contracts were recorded on the consolidated balance sheets at fair value in accordance with SFAS No. 133. Due to regulatory mechanisms, fair value changes did not affect earnings. At the time of modification, SCE had assets and liabilities related to mark-to-market gains or losses. Under SFAS No. 133, the assets and liabilities were reclassified to a lease prepayment or accrual and were included in the cost basis of the lease. The lease prepayment and accruals are being amortized over the life of the lease on a straight-line basis. At December 31, 2008, the net liability was $64 million. At December 31, 2008, SCE had 69 power contracts classified as operating leases. Operating lease expense for power purchases was $328 million in 2008, $297 million in 2007, and $188 million in 2006. In addition, as of December 31, 2008, SCE had four power purchase contracts which met the requirements for capital leases. These capital leases have a net commitment of $1.22 billion at December 31, 2008 and $20 million at December 31, 2007. SCE's total estimated capital lease executory costs and interest expense were $1.71 billion at December 31, 2008 and $20 million at December 31, 2007.

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 2009, $155 million in 2010, $160 million in both 2011 and 2012, and $149 million in 2013, and the total remaining minimum lease payments are $1.5 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 in 2009, $170 million in 2010, and $151 million in each 2011, 2012 and 2013, and the total remaining minimum lease payments are $489 million. The gain on the sale of the power facilities has been deferred and is being amortized over the term of the leases.

Under the terms of the foregoing sale-leaseback transactions, distributions are restricted by EME's subsidiaries unless specified financial covenants are met. At December 31, 2008, EME's subsidiaries met these covenants. In addition, the lease agreements and the Midwest Generation credit agreement contain covenants that include, among other things, restrictions on the ability of these subsidiaries to 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.

Edison International has other operating leases for office space, vehicles, property and other equipment (with varying terms, provisions and expiration dates). The following are estimated remaining commitments (the majority of other operating leases are related to EME's long-term leases for the Illinois power facilities and Homer City facilities discussed above) for noncancelable operating leases:

In millions	Year ending December 31,	Power Contracts Operating Leases	Other Operating Leases
2009		$ 638	$ 1,051
2010		625	1,023
2011		458	831
2012		355	719
2013		349	701
Thereafter		2,000	4,161
Total		**$ 4,425**	**$ 8,486**

The minimum commitments above do not include EME's 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.

As discussed above, SCE modified numerous power contracts which increased the noncancelable operating lease future commitments and decreased the power purchase commitments below in "Other Commitments."

Operating lease expense was $583 million in 2008, $539 million in 2007 and $420 million in 2006.

Nuclear Decommissioning Commitment

SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. The fair value of decommissioning SCE's nuclear power facilities is $2.9 billion as of December 31, 2008, based on site-specific studies performed in 2005 for San Onofre and Palo Verde. Changes in the estimated costs, timing of decommissioning, or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission. SCE estimates that it will spend approximately $11.5 billion through 2049 to decommission its active nuclear facilities. This estimate is based on SCE's decommissioning cost methodology used for rate-making purposes, escalated at rates ranging from 1.7% to 7.5% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately $46 million per year. SCE estimates annual after-tax earnings on the decommissioning funds of 4.4% to 5.8%. If the assumed return on trust assets is not earned, it is probable that additional funds needed for decommissioning will be recoverable through rates in the future. If the assumed return on trust assets is greater than estimated, funding amounts may be reduced through future decommissioning proceedings.

Decommissioning of San Onofre Unit 1 is underway and will be completed in three phases: (1) decontamination and dismantling of all structures and some foundations; (2) spent fuel storage monitoring; and (3) fuel storage facility dismantling, removal of remaining foundations, and site restoration. Phase one was scheduled to continue through 2008. Phase two is expected to continue until 2026. Phase three will be conducted concurrently with the San Onofre Units 2 and 3 decommissioning projects. In February 2004, SCE announced that it discontinued plans to ship the San Onofre Unit 1 reactor pressure vessel to a disposal site until such time as appropriate arrangements are made for its permanent disposal. It will continue to be stored at its current location at San Onofre Unit 1. This action results in placing the disposal of the reactor pressure vessel in Phase three of the San Onofre Unit 1 decommissioning project.

All of SCE's San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds and are subject to CPUC review. The estimated remaining cost to decommission San Onofre Unit 1 is recorded as an ARO liability ($59 million at December 31, 2008). Total expenditures for the decommissioning of San Onofre Unit 1 were $583 million from the beginning of the project in 1998 through December 31, 2008.

Decommissioning expense under the rate-making method was $46 million, $46 million and $32 million in 2008, 2007 and 2006, respectively. The ARO for decommissioning SCE's active nuclear facilities was $2.9 billion and $2.7 billion at December 31, 2008 and 2007, respectively.

See "Nuclear Decommissioning Trusts" in Note 10 for discussion on fair value of the trusts.

Other Commitments

SCE has fuel supply contracts which require payment only if the fuel is made available for purchase. SCE has a coal fuel contract that requires payment of certain fixed charges whether or not coal is delivered.

SCE has power purchase contracts with certain QFs (cogenerators and small power producers) and other power producers. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE (the energy payments are not included in the table below). There are no requirements to make debt-service payments. In an effort to replace higher-cost contract payments with lower-cost replacement power, SCE has entered into power purchase settlements to end its contract obligations with certain QFs. The settlements are reported as power purchase contracts on the consolidated balance sheets.

Certain commitments for the years 2009 through 2013 are estimated below:

In millions	2009	2010	2011	2012	2013
Fuel supply	$ 667	$ 278	$ 173	$ 202	$ 192
Gas and coal transportation payments	$ 244	$ 168	$ 7	$ 8	$ 7
Purchased power	$ 289	$ 368	$ 519	$ 681	$ 660

SCE has an unconditional purchase obligation for firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the transmission service provider, whether or not the transmission line is operable. The contract requires minimum payments of $60 million through 2016 (approximately $7 million per year).

At December 31, 2008, EME's subsidiaries had firm commitments to spend approximately $150 million in 2009 on capital and construction expenditures. The majority of these expenditures primarily relate to the construction of wind projects and environmental improvements at the Illinois Plants. These expenditures are planned to be financed by cash on hand and cash generated from operations.

EME had entered into various turbine supply agreements with vendors to support its wind development efforts. At December 31, 2008, EME had secured 484 wind turbines (942 MW) for use in future projects for an aggregate purchase price of $1.2 billion, with remaining commitments of $706 million in 2009 and $232 million in 2010. One of EME's turbine suppliers has requested an escalation adjustment to its pricing for 2008 and 2009 turbines pursuant to its turbine supply agreement. EME is evaluating the request, and discussions with the supplier are ongoing. At December 31, 2008 and 2007, EME had recorded wind turbine deposits of $327 million and $273 million, respectively, included in other long-term assets on its consolidated balance sheet. Under certain of these agreements, EME may terminate the purchase of individual turbines, or groups of turbines, for convenience. Upon any such termination, EME may be obligated to pay termination charges to the vendor.

In 2008, EME had entered into an agreement to purchase 5 gas-fired turbines (479 MW) for use in the Walnut Creek project. During the fourth quarter of 2008, EME and its subsidiary terminated the turbine supply agreement for the project to preserve capital and recorded a pre-tax charge of $23 million ($14 million, after tax) reflected in "Contract buyout/termination and other" on Edison International's consolidated statements of income. EME plans to purchase turbines for the project subject to resolution of uncertainty regarding the availability of required emission credits.

At December 31, 2008, Midwest Generation and EME Homer City had fuel purchase commitments with various third-party suppliers. Based on the contract provisions, which consist of fixed prices, subject to adjustment clauses, these minimum commitments are currently estimated to aggregate $638 million in the next four years summarized as follows: 2009 – $460 million; 2010 – $160; 2011 – $14 million; and 2012 – $4 million.

In connection with the acquisition of the Illinois Plants, Midwest Generation had assumed a long-term coal supply contract and recorded a liability to reflect the fair value of this contract. In March 2008, Midwest Generation entered into an agreement to buy out its coal obligations for the years 2009 through 2012 under this contract with a one-time payment to be made in January 2009. Midwest Generation recorded a pre-tax gain of $15 million ($9 million, after tax) during the first quarter of 2008 reflected in "Contract buyout/termination and other" on Edison International's consolidated statements of income.

At December 31, 2008, 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 nine years, is currently estimated to aggregate $40 million in the next five years, $8 million each year, 2009 through 2013. EME has entered into agreements to re-sell the transportation under this agreement which aggregates $50 million over the same period.

At December 31, 2008, Midwest Generation had contractual commitments for the transport of coal to their respective facilities. 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 its fuel supply contracts. Based on the committed coal volumes in the fuel supply contracts described above, these minimum commitments are currently estimated to aggregate $396 million in the next two years, summarized as follows: 2009 – $236 million and 2010 – $160 million.

At December 31, 2008, EME and its subsidiaries were party to a long-term power purchase contract, a coal cleaning agreement, turbine operations and maintenance agreements, and agreements for the purchase of limestone, ammonia and materials for environmental controls equipment. These minimum commitments are currently estimated to aggregate $286 million in the next five years: 2009 – $59 million; 2010 – $78 million; 2011 – $67 million; 2012 – $56 million; and 2013 – $26 million.

Guarantees and Indemnities

Edison International's subsidiaries have various financial and performance guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts included performance guarantees, guarantees of debt and indemnifications.

Tax Indemnity Agreements

In connection with the sale-leaseback transactions related to the Homer City facilities in Pennsylvania, the Powerton and Joliet Stations in Illinois and, previously, the Collins Station in Illinois, EME and several of its subsidiaries entered into tax indemnity agreements. Although the Collins Station lease terminated in April 2004, Midwest Generation's tax indemnity agreement with the former lease equity investor is still in effect. 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.

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 takes 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. Commonwealth Edison has advised EME that Commonwealth Edison believes it is entitled to indemnification for all liabilities, costs, and expenses that it may be required to bear as a result of the NOV discussed below under "— Contingencies — Midwest Generation New Source Review Notice of Violation" and potential litigation by private groups related to the NOV. 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 had an initial five-year term with an automatic renewal provision for subsequent one-year terms (subject to the right of either party to terminate); pursuant to the automatic renewal provision, it has been extended until February 2010. There were approximately 222 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed at December 31, 2008. Midwest Generation had recorded a $52 million and $54 million liability at December 31, 2008 and 2007, respectively, related to this matter.

Midwest Generation recorded an undiscounted liability for its indemnity for future asbestos claims through 2045. During the fourth quarter of 2007, the liability was reduced by $9 million based on updated estimated losses. In calculating future losses, various assumptions were made, 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 no asbestos claims will be filed after 2044.

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 valid 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. See "— Contingencies — EME Homer City New Source Review Notice of Violation" for discussion of the NOV received by EME Homer City and associated indemnity claims. 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, 2008 and 2007, EME had recorded a liability of $95 million (of which $51 million is classified as a current liability) and $101 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. At December 31, 2008, EME had recorded a liability of $13 million related to these matters.

Indemnity Provided as Part of the Acquisition of Mountainview

In connection with the acquisition of Mountainview, SCE agreed to indemnify the seller with respect to specific environmental claims related to SCE's previously owned San Bernardino Generating Station, divested by SCE in 1998 and reacquired as part of the Mountainview acquisition. SCE retained certain responsibilities with respect to environmental claims as part of the original divestiture of the station. The aggregate liability for either party to the purchase agreement for damages and other amounts is a maximum of $60 million. This indemnification for environmental liabilities expires on or before March 12, 2033. SCE has not recorded a liability related to this indemnity.

Mountainview Filter Cake Indemnity

Mountainview owns and operates a power plant in Redlands, California. The plant utilizes water from on-site groundwater wells and City of Redlands (City) recycled water for cooling purposes. Unrelated to the operation of the plant, this water contains perchlorate. The pumping of the water removes perchlorate from the aquifer beneath the plant and concentrates it in the plant's wastewater treatment "filter cake." Use of this impacted groundwater for cooling purposes was mandated by Mountainview's California Energy Commission permit. Mountainview has indemnified the City for cleanup or associated actions related to groundwater contaminated by perchlorate due to the disposal of filter cake at the City's solid waste landfill. The obligations under this agreement are not limited to a specific time period or subject to a maximum liability. SCE has not recorded a liability related to this guarantee.

Other Edison International Indemnities

Edison International provides other indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, and specified environmental indemnities and income taxes with respect to assets sold. Edison International's obligations under these agreements may be limited in terms of time and/or amount, and in some instances Edison International may have recourse against third parties for certain indemnities. The obligated amounts of these indemnifications often are not explicitly stated, and the overall maximum amount of the obligation under these indemnifications cannot be reasonably estimated. Edison International has not recorded a liability related to these indemnities.

Contingencies

In addition to the matters disclosed in these Notes, Edison International is involved in other legal, tax and regulatory proceedings before various courts and governmental agencies regarding matters arising in the ordinary course of business. Edison International believes the outcome of these other proceedings will not materially affect its results of operations or liquidity.

Environmental Remediation

Edison International is subject to numerous environmental laws and regulations, which require it to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment.

Edison International believes that it is in substantial compliance with environmental regulatory requirements; however, possible future developments, such as the enactment of more stringent environmental laws and regulations, could affect the costs and the manner in which business is conducted and could cause substantial additional capital expenditures. There is no assurance that additional costs would be recovered from customers or that Edison International's financial position and results of operations would not be materially affected.

Edison International records its environmental remediation liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. Edison International reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site using currently available information, including existing technology, presently enacted laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. These estimates include costs for site investigations, remediation, operations and maintenance, monitoring and site closure. Unless there is a probable amount, Edison International records the lower end of this reasonably likely range of costs (classified as other long-term liabilities) at undiscounted amounts.

As of December 31, 2008, Edison International's recorded estimated minimum liability to remediate its 45 identified sites at SCE (24 sites) and EME (21 sites primarily related to Midwest Generation) was $45 million, $41 million of which was related to SCE including $10 million related to San Onofre. This remediation liability is undiscounted. Edison International's other subsidiaries have no identified remediation sites. The ultimate costs to clean up Edison International's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. Edison International believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $173 million, all of which is related to SCE. The upper limit of this range of costs was estimated using assumptions least favorable to Edison International among a range of reasonably possible outcomes. In addition to its identified sites (sites in which the upper end of the range of costs is at least $1 million), SCE also has 30 immaterial sites whose total liability ranges from $3 million (the recorded minimum liability) to $9 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $29 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $40 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

Edison International's identified sites include several sites for which there is a lack of currently available information, including the nature and magnitude of contamination, and the extent, if any, that Edison International may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can be made for these sites.

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $11 million to $31 million. Recorded costs were $29 million, $25 million and $14 million for 2008, 2007 and 2006, respectively.

Based on currently available information, Edison International believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range for its identified sites and, based upon the CPUC's regulatory treatment of environmental remediation costs incurred at SCE, Edison International believes that costs ultimately recorded will not materially affect its results of operations or financial position. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

Federal and State Income Taxes

Edison International remains subject to examination and administrative appeals by the IRS for various tax years. As part of a nationwide challenge of certain types of lease transactions, the IRS has raised issues about the deferral of income taxes associated with its cross-border, leveraged leases. See Note 4, for further details.

2009 FERC Rate Case

In an order issued in September 2008, the FERC accepted and made effective on March 1, 2009, subject to refund and settlement procedures, SCE's proposed revisions to its tariff, filed in the 2009 transmission rate case. The revisions reflected changes to SCE's transmission revenue requirement and transmission rates, as discussed below.

SCE requested a $129 million increase in its retail transmission revenue requirements (or a 39% increase over the current retail transmission revenue requirement) due to an increase in transmission capital-related costs and increases in transmission operating and maintenance expenses that SCE expects to incur in 2009 to maintain grid reliability. The transmission revenue requirement request is based on a return on equity of 12.7%, which is composed of a 12.0% base ROE and 0.7% in transmission incentives previously approved by the FERC (see "FERC Transmission Incentives" below for further information). SCE is unable to predict the revenue requirement that the FERC will ultimately authorize.

FERC Transmission Incentives

The Energy Policy Act of 2005 established incentive-based rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. Pursuant to this act, in November 2007, the FERC issued an order granting incentives on three of SCE's largest proposed transmission projects. These include 125 basis point ROE adders on SCE's proposed base ROE for SCE's DPV2 and Tehachapi transmission projects and a 75 basis point ROE adder for SCE's Rancho Vista Substation Project ("Rancho Vista").

In June 2007, the ACC denied the approval of the DPV2 project which resulted in an estimated two year delay of the project. SCE continues its efforts to obtain the regulatory approvals necessary to construct the DPV2 project and continues to evaluate its options, which include but are not limited to, filing a new application with the ACC and building the project in various phases.

The order also grants a 50 basis point ROE adder on SCE's cost of capital for its entire transmission rate base in SCE's next FERC transmission rate case for SCE's participation in the CAISO. In addition, the order on incentives permits SCE to include in rate base 100% of prudently-incurred capital expenditures during construction, also known as CWIP, of all three projects and 100% recovery of prudently-incurred abandoned plant costs for two of the projects, if either are cancelled due to factors beyond SCE's control.

In August 2008, the CPUC filed an appeal of the FERC incentives order at the DC Circuit Court of Appeals. The court issued a ruling on November 6, 2008, accepting the CPUC's request that the court refrain from ruling on the CPUC's appeal until a final FERC order is issued in the 2008 CWIP case. (See "FERC Construction Work in Progress Mechanism" below for further information).

FERC Construction Work in Progress Mechanism

FERC CWIP 2008

In February 2008, the FERC approved SCE's revision to its tariff to collect 100% of CWIP in rate base for its Tehachapi, DPV2, and Rancho Vista, as authorized by FERC in its transmission incentives order discussed above which resulted in an authorized base transmission revenue requirement of $45 million, subject to refund. In March 2008, the CPUC filed a petition for rehearing with the FERC on the FERC's acceptance of SCE's proposed ROE for CWIP and in another 2008 protest to an SCE compliance filing, requested an evidentiary hearing to be set to further review SCE's costs. SCE cannot predict the outcome of the matters in this proceeding.

FERC CWIP 2009

SCE filed its 2009 CWIP rate adjustment in October 2008 proposing a reduction to its CWIP revenue requirement from $45 million to $39 million to be effective on January 1, 2009. Several parties, including the CPUC, filed protests to the October filing in November 2008, primarily contesting SCE's proposed base ROE of 12.0%. The FERC issued an order in December 2008, allowing the proposed 2009 CWIP rates to go into effect on January 1, 2009, subject to refund, and directing that the 2009 CWIP ROE be made subject to the outcome of the pending 2008 FERC CWIP proceeding. The FERC also consolidated all issues other than ROE with SCE's 2009 FERC rate case proceeding.

EME Homer City New Source Review Notice of Violation

On June 12, 2008, EME Homer City received an NOV from the US EPA alleging that, beginning in 1988, EME Homer City (or former owners of the Homer City facilities) performed repair or replacement projects at Homer City Units 1 and 2 without first obtaining construction permits as required by the Prevention of Significant Deterioration requirements of the CAA. The US EPA also alleges that EME Homer City has failed to file timely and complete Title V permits. EME Homer City has met with the US EPA and has expressed its intent to explore the possibility of a settlement. If no settlement is reached and the DOJ files suit, litigation could take many years to resolve the issues alleged in the NOV. EME Homer City cannot predict at this time what effect this matter may have on its facilities, its results of operations, financial position or cash flows.

EME Homer City has sought indemnification for liability and defense costs associated with the NOV from the sellers under the asset purchase agreement pursuant to which EME Homer City acquired the Homer City facilities. The sellers responded by denying the indemnity obligation, but accepting the defense of the claims.

EME Homer City notified the sale-leaseback owner participants of the Homer City facilities of the NOV under the operative indemnity provisions of the sale-leaseback documents. The owner participants of the Homer City facilities, in turn, have sought indemnification and defense from EME Homer City for costs and liability associated with the EME Homer City NOV. EME Homer City responded by undertaking the indemnity obligation and defense of the claims.

Four Corners CPUC Emissions Performance Standard Ruling

The emission performance standards adopted by the CPUC and CEC pursuant to SB 1368 prohibits SCE and other California load-serving entities from entering into long-term financial commitments with generators that emit more than 1,100 pounds of CO_2 per MWh, which would include most coal-fired plants. In January 2008, SCE filed a petition with the CPUC seeking clarification that the emission performance standard would not apply to capital expenditures required by existing agreements among the owners at Four Corners. The CPUC issued a proposed decision finding that the emission performance standard was not intended to apply to capital expenditures at Four Corners requested by SCE in its GRC for the period 2007 – 2011. In October 2008, the Assigned Commissioner and Administrative Law Judge issued a ruling withdrawing the proposed decision and seeking additional comment on whether the finding in the proposed decision should be changed and whether SCE should be allowed to recover such capital expenditures. SCE estimates that its share of capital expenditures approved by the owners at Four Corners since the GHG emission performance standard decision was issued in January 2007 is approximately $43 million, of which approximately $8 million had been expended through December 31, 2008. The ruling also directs SCE to explain why certain information was not included in its petition and why the failure to include such information should not be considered misleading in violation of CPUC rules. SCE filed its response and comments to the ruling in November and December 2008 and cannot predict the outcome of this proceeding or estimate the amount, if any, of penalties or disallowances that may be imposed.

ISO Disputed Charges

On April 20, 2004, the FERC issued an order concerning a dispute between the ISO and the Cities of Anaheim, Azusa, Banning, Colton and Riverside, California over the proper allocation and characterization of certain transmission service related charges. The potential cost to SCE of the FERC order, net of amounts SCE expects to receive through the PX, SCE's scheduling coordinator at the pertinent time, is estimated to be approximately $20 million to $25 million, including interest. The order has been the subject of continuing legal proceedings since it was issued. SCE believes that the most recent substantive order FERC has issued in the proceedings correctly allocates responsibility for these ISO charges. However, SCE cannot predict the final outcome of the rehearing. If a subsequent regulatory decision changes the allocation of responsibility for these charges, and SCE is required to pay these charges as a transmission owner, SCE may seek recovery in its reliability service rates. SCE cannot predict whether recovery of these charges in its reliability service rates would be permitted.

Leveraged Lease Investments

At December 31, 2008, Edison Capital had a net leveraged lease investment, before deferred taxes, of $50 million in three aircraft leased to American Airlines. American Airlines reported net losses during 2008 and previously reported losses for a number of years prior to 2006. A default in the leveraged lease by American Airlines could result in a loss of some or all of Edison Capital's lease investment. At December 31, 2008, American Airlines was current in its lease payments to Edison Capital.

Midwest Generation New Source Review Notice of Violation

On August 3, 2007, Midwest Generation received an NOV from the US EPA alleging that, beginning in the early 1990s and into 2003, Midwest Generation or Commonwealth Edison performed repair or replacement projects at six Illinois coal-fired electric generating stations in violation of the Prevention of Significant Deterioration requirements and of the New Source Performance Standards of the CAA, including alleged requirements to obtain a construction permit and to install best available control technology at the time of the projects. The US EPA also alleges that Midwest Generation and Commonwealth Edison violated certain operating permit requirements under Title V of the CAA. Finally, the US EPA alleges violations of certain opacity and particulate matter standards at the Illinois Plants. The NOV does not specify the penalties or other relief that the US EPA seeks for the alleged violations. Midwest Generation, Commonwealth Edison, the US EPA, and the DOJ are in talks designed to explore the possibility of a settlement. If the settlement talks fail and the DOJ files suit, litigation could take many years to resolve the issues alleged in the NOV. Midwest Generation cannot predict the outcome of this matter or estimate the impact on its facilities, its results of operations, financial position or cash flows.

On August 13, 2007, Midwest Generation and Commonwealth Edison received a letter signed by several Chicago-based environmental action groups stating that, in light of the NOV, the groups are examining the possibility of filing a citizen suit against Midwest Generation and Commonwealth Edison based presumably on the same or similar theories advanced by the US EPA in the NOV.

By letter dated August 8, 2007, Commonwealth Edison advised EME that Commonwealth Edison believes it is entitled to indemnification for all liabilities, costs, and expenses that it may be required to bear as a result of the NOV. By letter dated August 16, 2007, Commonwealth Edison tendered a request for indemnification to EME for all liabilities, costs, and expenses that Commonwealth Edison may be required to bear if the environmental groups were to file suit. Midwest Generation and Commonwealth Edison are cooperating with one another in responding to the NOV.

Navajo Nation Litigation

The Navajo Nation filed a complaint in June 1999 in the District Court against SCE, among other defendants, arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal RICO statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentations by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal supplied to Mohave. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion. In March 2001, the Hopi Tribe was permitted to intervene as an additional plaintiff but has not yet identified a specific amount of damages claimed. The case was stayed at the request of the parties in October 2004, but was reinstated to the active calendar in March 2008.

A related case against the U.S. Government is presently before the U.S. Supreme Court. The outcome of that case could affect the Navajo Nation's pursuit of claims against SCE. A decision from the U.S. Supreme Court is expected in mid-2009.

SCE cannot predict the outcome of the Tribe's complaints against SCE or the ultimate impact on these complaints of the on-going litigation by the Navajo Nation against the U.S. Government in the related case.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to the amount of available financial protection, which is currently approximately $12.5 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($300 million). The balance is covered by the industry's retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the United States results in claims and/or costs which exceed the primary insurance at that plant site.

Federal regulations require this secondary level of financial protection. The NRC exempted San Onofre Unit 1 from this secondary level, effective June 1994. Beginning October 29, 2008, the maximum deferred premium for each nuclear incident is approximately $118 million per reactor, but not more than approximately $18 million per reactor may be charged in any one year for each incident. The maximum deferred premium per reactor and the yearly assessment per reactor for each nuclear incident is adjusted for inflation at least once every five years. The most recent inflation adjustment took effect on October 29, 2008. Based on its ownership interests, SCE could be required to pay a maximum of approximately $235 million per nuclear incident. However, it would have to pay no more than approximately $35 million per incident in any one year. Such amounts include a 5% surcharge if additional funds are needed to satisfy public liability claims and are subject to adjustment for inflation. If the public liability limit above is insufficient, federal law contemplates that additional funds may be appropriated by Congress. This could include an additional assessment on all licensed reactor operators as a measure for raising further electric utility revenue.

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. A mutual insurance company owned by utilities with nuclear facilities issues these policies. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to approximately $45 million per year. Insurance premiums are charged to operating expense.

Palo Verde Nuclear Generating Station Outage and Inspection

The NRC held three special inspections of Palo Verde, between March 2005 and February 2007. The combination of the results of the first and third special inspections caused the NRC to undertake an additional oversight inspection of Palo Verde. This additional inspection, known as a supplemental inspection, was completed in December 2007. In addition, Palo Verde was required to take additional corrective actions based on the outcome of completed surveys of its plant personnel and self-assessments of its programs and procedures. The NRC and APS defined and agreed to inspection and survey corrective actions that the NRC embodied in a Confirmatory Action Letter, which was issued in February 2008. APS is presently on track to complete the corrective actions required to close the Confirmatory Action Letter by mid-2009. Palo Verde operation and maintenance costs (including overhead) increased in 2007 by approximately $7 million from 2006. SCE estimates that operation and maintenance costs will increase by approximately $23 million (in 2007 dollars) over the two year period 2008 – 2009, from 2007 recorded costs including overhead costs. SCE is unable to estimate how long SCE will continue to incur these costs. In the 2009 GRC, SCE requested recovery of, and two-way balancing account treatment for, Palo Verde operation and maintenance expenses including costs associated with these corrective actions. If approved, this would provide for recovery of these costs over the three-year GRC cycle.

Procurement of Renewable Resources

California law requires SCE to increase its procurement of renewable resources by at least 1% of its annual retail electricity sales per year so that 20% of its annual electricity sales are procured from renewable resources by no later than December 31, 2010.

It is unlikely that SCE will have 20% of its annual electricity sales procured from renewable resources by 2010. However, SCE may still meet the 20% target by utilizing the flexible compliance rules, such as banking of past surplus and earmarking of future deliveries from executed contracts. SCE continues to engage in several renewable procurement activities including formal solicitations approved by the CPUC, bilateral negotiations with individual projects and other initiatives.

Under current CPUC decisions, potential penalties for SCE's inability to achieve its renewable procurement objectives for any year will be considered by the CPUC in the context of the CPUC's review of SCE's annual compliance filing. Under the CPUC's current rules, the maximum penalty for inability to achieve renewable procurement targets is $25 million per year. SCE does not believe it will be assessed penalties for 2008 or the prior years and cannot predict whether it will be assessed penalties for future years.

RPM Buyers' Complaint

On May 30, 2008, a group of entities referring to themselves as the "RPM Buyers" filed a complaint at the FERC asking that PJM's RPM, as implemented through the transitional base residual auctions establishing capacity payments for the period from June 1, 2008 through May 31, 2011, be found to have produced unjust and unreasonable capacity prices. On September 19, 2008, the FERC dismissed the RPM Buyers' complaint, finding that the RPM Buyers had failed to allege or prove that any party violated PJM's tariff and market rules, and that the prices determined during the transition period were determined in accordance with PJM's FERC-approved tariff. On October 20, 2008, the RPM Buyers requested rehearing of the FERC's order dismissing their complaint. This matter is currently pending before the FERC. EME cannot predict the outcome of this matter.

Spent Nuclear Fuel

Under federal law, the DOE is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE did not meet its contractual obligation to begin acceptance of spent nuclear fuel by January 31, 1998. It is not certain when the DOE will begin accepting spent nuclear fuel from San Onofre or other nuclear power plants. Extended delays by the DOE have led to the construction of costly alternatives and associated siting and environmental issues. SCE has paid the DOE the required one-time fee applicable to nuclear generation at San Onofre (approximately $24 million, plus interest). SCE has also been paying a required quarterly fee equal to 0.1¢ per-kWh of nuclear-generated electricity sold after April 6, 1983. On January 29, 2004, SCE, as operating agent, filed a complaint against the DOE in the United States Court of Federal Claims seeking damages for the DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre.

SCE has primary responsibility for the interim storage of spent nuclear fuel generated at San Onofre. Such interim storage for San Onofre is on-site.

APS, as operating agent, has primary responsibility for the interim storage of spent nuclear fuel at Palo Verde. Palo Verde plans to add storage capacity incrementally to maintain full core off-load capability for all three units. In order to increase on-site storage capacity and maintain core off-load capability, Palo Verde has constructed an independent spent fuel storage facility.

Note 7. Accumulated Other Comprehensive Income (Loss)

Edison International's accumulated other comprehensive income (loss), including discontinued operations, consists of:

	Unrealized Gains (Losses) on Cash Flow Hedges	Foreign Currency Translation Adjustment	Pension and PBOP– Net Loss	Pension and PBOP– Prior Service Cost	Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2006	$ 110	$ 1	$ (37)	$ 4	$ 78
Change for 2007	(170)	(2)	3	(1)	(170)
Balance at December 31, 2007	(60)	(1)	(34)	3	(92)
Change for 2008	300	(3)	(36)	(2)	259
Balance at December 31, 2008	**$ 240**	**$ (4)**	**$ (70)**	**$ 1**	**$ 167**

SFAS No. 158 — postretirement benefits is discussed in "Pension Plans and Postretirement Benefits Other Than Pensions" in Note 5.

Unrealized gains on cash flow hedges, net of tax, at December 31, 2008, included 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. As EME's hedged positions for continuing operations are realized, $149 million, after tax, of the net unrealized gains on cash flow hedges at December 31, 2008 are expected to be reclassified into earnings during the next 12 months. Management expects that reclassification of net unrealized gains will increase nonutility power generation 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, 2011.

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 gains (losses) of $7 million, $(41) million and $(6) million in 2008, 2007 and 2006, respectively, representing the amount of cash flow hedges' ineffectiveness for continuing operations, reflected in nonutility power generation operating revenues on Edison International's consolidated income statements.

On September 15, 2008, Lehman Brothers Holdings filed for protection under Chapter 11 of the U.S. Bankruptcy Code. EME had power contracts with Lehman Brothers Commodity Services, Inc., a subsidiary of Lehman Brothers Holdings, for Midwest Generation for 2009 and 2010. Lehman Brothers Commodity Services also filed for bankruptcy protection on October 3, 2008. The obligations of Lehman

Brothers Commodity Services under the power contracts were guaranteed by Lehman Brothers Holdings. These contracts qualified as cash flow hedges under SFAS No. 133 until EME dedesignated the power contracts effective September 12, 2008 when it determined that it was no longer probable that performance would occur. The amount recorded in accumulated comprehensive income (loss) related to the effective portion of the hedges was $24 million pre-tax ($15 million, after tax) on that date. Since the power contracts are no longer being accounted for as cash flow hedges under SFAS No. 133 and subsequently were terminated, the subsequent change in fair value was recorded as an unrealized loss in 2008 and included in nonutility generation power revenues on EME's consolidated statement of income. Under SFAS No. 133, the pre-tax amount recorded in accumulated other comprehensive income (loss) will be reclassified to operating nonutility generation power revenue based on the original forecasted transactions in 2009 ($15 million) and 2010 ($9 million), unless it becomes probable that the forecasted transactions will no longer occur.

EME has established claims in the amount of $48 million related to the contracts terminated with Lehman Brothers Holdings and its subsidiary as described above through the termination provisions of its master netting agreements with a Lehman Brothers Holdings subsidiary. Such claims have been fully reserved and are included net in prepaid expenses and other on EME's consolidated balance sheet.

Note 8. Property and Plant

Nonutility Property

Nonutility property included on the consolidated balance sheets is composed of:

In millions December 31,	2008	2007
Furniture and equipment	**$ 82**	$ 90
Building, plant and equipment	**5,250**	4,490
Land (including easements)	**80**	85
Emission allowances	**1,305**	1,305
Leasehold improvements	**132**	110
Construction in progress	**544**	591
	7,393	6,671
Accumulated provision for depreciation	**(2,019)**	(1,765)
Nonutility property – net	**$ 5,374**	$ 4,906

The power sales agreements of certain wind projects qualify as operating leases under EITF No. 01-8, and SFAS No. 13, "Accounting for Leases." The carrying amount and related accumulated depreciation of the property of these wind projects totaled $901 million and $62 million, respectively, at December 31, 2008, and $559 million and $28 million, respectively, at December 31, 2007. EME records rental income from wind projects that are accounted for as operating leases as electricity is delivered at rates defined in power sales agreements. Revenue from these power sales agreements were $46 million, $24 million and $10 million in 2008, 2007 and 2006, respectively.

Asset Retirement Obligations

As a result of the adoption of SFAS No. 143 in 2003, Edison International recorded the fair value of its liability for legal AROs, which was primarily related to the decommissioning of SCE's nuclear power facilities. In addition, SCE capitalized the initial costs of the ARO into a nuclear-related ARO regulatory asset, and also recorded an ARO regulatory liability as a result of timing differences between the recognition of costs recorded in accordance with the standard and the recovery of the related asset retirement costs through the rate-making process. SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. The fair value of the nuclear decommissioning trusts was $2.5 billion at December 31, 2008. For a further discussion about nuclear decommissioning trusts see "Nuclear Decommissioning Commitment" in Note 6 and "Nuclear Decommission Trusts" in Note 10.

A reconciliation of the changes in the ARO liability is as follows:

In millions	2008	2007	2006
Beginning balance	**$ 2,892**	$ 2,759	$ 2,628
Accretion expense	**176**	169	160
Revisions	**(13)**	3	—
Liabilities added	**22**	7	42
Liabilities settled	**(35)**	(46)	(71)
Ending balance	**$ 3,042**	$ 2,892	$ 2,759

The ARO liability as of December 31, 2008 includes an ARO liability of $2.9 billion related to nuclear decommissioning.

Note 9. Supplemental Cash Flow Information

Edison International's supplemental cash flows information is:

In millions **Year ended December 31,**	2008	2007	2006
Cash payments for interest and taxes:			
Interest – net of amounts capitalized	**$ 638**	$ 709	$ 739
Tax payments – net	**$ 377**	$ 332	$ 826
Noncash investing and financing activities:			
Details of debt exchange:			
Pollution-control bonds redeemed	**$ —**	$ —	$ (331)
Pollution-control bonds issued	**$ —**	$ —	$ 331
Details of capital lease obligations:			
Capital lease purchased	**$ —**	$ (10)	$ —
Capital lease obligation issued	**$ —**	$ 10	$ —
Dividends declared but not paid			
Common Stock	**$ 101**	$ 99	$ 94
Preferred and preference stock of utility not subject to mandatory redemption	**$ 13**	$ 13	$ 9
Details of assets acquired:			
Fair value of assets acquired	**$ —**	$ 41	$ 29
Liabilities assumed	**$ —**	$ —	$ —
Net assets acquired	**$ —**	$ 41	$ 29
Details of consolidation of variable interest entities:			
Assets	**$ 3**	$ 12	$ 18
Liabilities	**$ (4)**	$ (5)	$ (4)

In connection with certain wind projects acquired during the past three years, the purchase price included payments that were due upon the start and/or completion of construction. Accordingly, EME accrued for estimated payments or made payments that were due upon commencement of construction and/or completion of construction scheduled during 2007 through 2009.

During the year ended December 31, 2006, 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 Notes 16 and 18 for further discussions.

Note 10. Fair Value Measurements

SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (referred to as an "exit price" in SFAS No. 157). SFAS No. 157 clarifies that a fair value measurement for a liability should reflect the entity's non-performance risk. In addition, SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets and liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy under SFAS No. 157 are:

- Level 1 – Unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets and liabilities;
- Level 2 – Pricing inputs include quoted prices for similar assets and liabilities in active markets and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument; and
- Level 3 – Prices or valuations that require inputs that are both significant to the fair value measurements and unobservable.

Edison International's assets and liabilities carried at fair value primarily consist of derivative contracts, SCE nuclear decommissioning trust investments and money market funds. Derivative contracts primarily relate to power and gas and include contracts for forward physical sales and purchases, options and forward price swaps which settle only on a financial basis (including futures contracts). Derivative contracts can be exchange traded or over-the-counter traded.

The fair value of derivative contracts takes into account quoted market prices, time value of money, volatility of the underlying commodities and other factors. Derivatives that are exchange traded in active markets for identical assets or liabilities are classified as Level 1. The majority of EME's derivative contracts used for hedging purposes are based on forward market prices in active markets (PJM West Hub, Northern Illinois Hub and AEP/Dayton) adjusted for non-performance risks. EME obtains forward market prices from traded exchanges (ICE Futures U.S. or New York Mercantile Exchange) and available broker quotes. Then, EME selects a primary source that best represents traded activity for each market to develop observable forward market prices in determining the fair value of these positions. Broker quotes or prices from exchanges are used to validate and corroborate the primary source. These price quotations reflect mid-market prices (average of bid and ask) and are obtained from sources that EME believes to provide the most liquid market for the commodity. EME considers broker quotes to be observable when corroborated with other information which may include a combination of prices from exchanges, other brokers and comparison to executed trades. The majority of the fair value of EME's derivative contracts determined in this manner are classified as Level 2. SCE's Level 2 derivatives primarily consist of financial natural gas swaps, fixed float swaps, and natural gas physical trades for which SCE obtains the applicable Henry Hub and basis forward market prices from the New York Mercantile Exchange and Intercontinental Exchange.

Level 3 includes the majority of SCE's derivatives, including over-the-counter options, bilateral contracts, capacity contracts, and QF contracts. The fair value of these SCE derivatives is determined using uncorroborated non-binding broker quotes (from one or more brokers) and models which may require SCE to extrapolate short-term observable inputs in order to calculate fair value. Broker quotes are obtained from several brokers and compared against each other for reasonableness. SCE has Level 3 fixed float swaps for which SCE obtains the applicable Henry Hub and basis forward market prices from the New York Mercantile Exchange. However, these swaps have contract terms that extend beyond observable market data and the unobservable inputs incorporated in the fair value determination are considered significant compared to the overall swap's fair value.

Level 3 also includes derivatives that trade infrequently (such as financial transmission rights, FTRs and CRRs in the California market and over-the-counter derivatives at illiquid locations), derivatives with counterparties that have significant non-performance risks as discussed below and long-term power agreements. For illiquid financial transmission rights, FTRs and CRRs, Edison International reviews objective criteria related to system congestion and other underlying drivers and adjusts fair value when Edison International concludes a change in objective criteria would result in a new valuation that better reflects the fair value. Recent auction prices are used to determine the fair value of short-term CRRs. Edison International recorded liquidity reserves against the long-term CRRs fair values since there were no quoted long-term market prices for the CRRs and insufficient evidence of long-term market prices.

Changes in fair values are based on the hypothetical sale of illiquid positions. For illiquid long-term power agreements, fair value is based upon a discounting of future electricity and natural gas prices derived from a proprietary model using the risk free discount rate for a similar duration contract, adjusted for credit risk and market liquidity. Changes in fair value are based on changes to forward market prices, including forecasted prices for illiquid forward periods. In circumstances where Edison International cannot verify fair value with observable market transactions, it is possible that a different valuation model could produce a materially different estimate of fair value. As markets continue to develop and more pricing information becomes available, Edison International continues to assess valuation methodologies used to determine fair value.

In assessing non-performance risks, EME reviews credit ratings of counterparties (and related default rates based on such credit ratings) and prices of credit default swaps. The market price (or premium) for credit default swaps represents the price that a counterparty would pay to transfer the risk of default, typically bankruptcy, to another party. A credit default swap is not directly comparable to the credit risks of derivative contracts, but provides market information of the related risk of non-performance. In light of recent market events, EME utilized market prices for credit default swaps in reducing the fair value of derivative assets by $6 million at December 31, 2008.

Investments in money market funds are generally classified as Level 1 as fair value is determined by observable market prices (unadjusted) in active markets. In 2008, EME had invested $20 million in the Reserve Primary Fund (a money market fund). The Reserve incurred a loss related to debt securities of Lehman Brothers Holdings and has announced liquidation of the Reserve. EME reduced the fair value of the investment by $1 million and transferred the remaining balance into Level 3 during the third quarter of 2008 as observable market prices were not available. During the fourth quarter of 2008, EME received $16 million in settlements resulting in the ending balance of $3 million at December 31, 2008 classified in Level 3.

The SCE nuclear decommissioning trust investments include equity securities, U.S. treasury securities and other fixed-income securities. Equity and treasury securities are classified as Level 1 as fair value is determined by observable market prices in active or highly liquid and transparent markets. The remaining fixed-income securities are classified as Level 2. The fair value of these financial instruments is based on evaluated prices that reflect significant observable market information such as reported trades, actual trade information of similar securities, benchmark yields, broker/dealer quotes, issuer spreads, bids, offers and relevant credit information.

The following table sets forth financial assets and liabilities that were accounted for at fair value as of December 31, 2008 by level within the fair value hierarchy:

In millions	Level 1	Level 2	Level 3	Netting and Collateral[1]	Total at December 31, 2008
			(Unaudited)		
Assets at Fair Value					
Money market funds[2]	$ 3,543	$ —	$ 3	$ —	$ 3,546
Derivative contracts	4	419	448	(225)	646
Nuclear decommissioning trusts[3]	1,502	1,026	—	—	2,528
Long-term disability plan	7	—	—	—	7
Total assets[4]	5,056	1,445	451	(225)	6,727
Liabilities at Fair Value					
Derivative contracts	(2)	(397)	(753)	123	(1,029)
Net assets (liabilities)	**$ 5,054**	**$ 1,048**	**$ (302)**	**$ (102)**	**$ 5,698**

(1) Represents cash collateral and the impact of netting across the levels of the fair value hierarchy. Netting among positions classified within the same level is included in that level.

(2) Included in cash and cash equivalents and short-term investments on Edison International's consolidated balance sheet.

(3) Excludes net liabilities of $4 million for interest and dividend receivables and receivables related to pending securities sales and payables related to pending securities purchases.

(4) Excludes $32 million of cash surrender value of life insurance investments for deferred compensation.

The following table sets forth a summary of changes in the fair value of Level 3 derivative contracts, net for the year ended December 31, 2008:

In millions	Year Ended December 31, 2008
Fair value of derivative contracts, net at January 1, 2008	$ 98
Total realized/unrealized gains (losses):	
Included in earnings[1]	297
Included in regulatory assets and liabilities[2]	(644)
Included in accumulated other comprehensive income	(2)
Purchases and settlements, net	(36)
Transfers in or out of Level 3	(18)
Fair value of derivative contracts, net at December 31	**$ (305)**
Change during the period in unrealized gains (losses) related to net derivative contracts, held at December 31, 2008[3]	**$ (448)**

(1) $297 million reported in "Nonutility power generation" revenue on Edison International's consolidated statement of income for the year ended December 31, 2008.

(2) Due to regulatory mechanisms, SCE's realized and unrealized gains and losses are recorded as regulatory assets and liabilities.

(3) $125 million reported in "Nonutility power generation" revenue on Edison International's consolidated statements of income for the year ended December 31, 2008. The remainder of the unrealized gains (losses) relates to SCE. See (2) above.

Nuclear Decommissioning Trusts

SCE is collecting in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. Funds collected, together with accumulated earnings, will be utilized solely for decommissioning. The CPUC has set certain restrictions related to the investments of these trusts.

Trust investments (at fair value) include:

In millions	Maturity Dates	December 31, 2008	December 31, 2007
Municipal bonds	2009 – 2044	**$ 629**	$ 561
Stocks	–	**1,308**	1,968
United States government issues	2009 – 2049	**304**	552
Corporate bonds	2009 – 2047	**260**	241
Short-term investments, primarily cash equivalents	2009	**23**	56
Total		**$ 2,524**	$ 3,378

Note: Maturity dates as of December 31, 2008.

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Net earnings (losses) were $(10) million, $143 million and $130 million in 2008, 2007 and 2006, respectively. Proceeds from sales of securities (which are reinvested) were $3.1 billion, $3.7 billion and $3.0 billion in 2008, 2007 and 2006, respectively. Unrealized holding gains, net of losses, were $618 million and $1.1 billion at December 31, 2008 and 2007, respectively. Approximately 92% of the cumulative trust fund contributions were tax-deductible.

The following table sets forth a summary of changes in the fair value of the trust for year ended December 31, 2008:

In millions	
Balance at beginning of period	$ 3,378
Realized losses – net	(65)
Unrealized losses – net	(545)
Other-than-temporary impairment	(317)
Earnings and other	73
Balance at December 31, 2008	**$ 2,524**

The decrease in the trust investments was primarily due to net unrealized losses and other-than-temporary impairment resulting from a volatile stock market environment. Due to regulatory mechanisms, earnings and realized gains and losses (including other-than-temporary impairments) have no impact on electric utility revenue.

Nuclear decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately $46 million per year. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. The next filing is in April 2009 for contribution changes in 2011. These contributions are determined based on an analysis of the current value of trusts assets and long-term forecasts of cost escalation, the estimate and timing of decommissioning costs, and after-tax return on trust investments. Favorable or unfavorable investment performance in a period will not change the amount of contributions for that period. However, trust performance for the three years leading up to a CPUC review proceeding will provide input into future contributions. The CPUC has set certain restrictions related to the investments of these trusts. If additional funds are needed for decommissioning, it is probable that the additional funds will be recoverable through customer rates.

Fair Values of Financial Instruments

The carrying amounts and fair values of financial instruments are:

In millions	December 31, 2008 Carrying Amount	2008 Fair Value	2007 Carrying Amount	2007 Fair Value
Derivatives:				
Interest rate hedges	**$ —**	**$ —**	$ (33)	$ (33)
Foreign currency hedge	**(33)**	**(33)**	3	3
Commodity price assets	**585**	**585**	82	82
Commodity price liabilities	**(944)**	**(944)**	(214)	(214)
QF power contracts liabilities	**(2)**	**(2)**	(3)	(3)
Other:				
Decommissioning trusts	**2,524**	**2,524**	3,378	3,378
Long-term debt	**(10,950)**	**(10,637)**	(9,016)	(8,995)
Long-term debt due within one year	**(174)**	**(175)**	(18)	(18)
Trading Activities:				
Assets	**286**	**286**	141	141
Liabilities	**(173)**	**(173)**	(9)	(9)

Fair values are based on: brokers' quotes and bank evaluations for interest rate hedges, foreign currency hedges and long-term debt. See "Fair Value Measurements" above for discussion of valuation of derivatives and the decommissioning trusts.

In January and February 2008, SCE settled interest rate locks resulting in realized losses of $33 million. A related regulatory asset was recorded in this amount and SCE is amortizing and recovering this amount as interest expense associated with its 2008 financings.

Note 11. Regulatory Assets and Liabilities

Included in SCE's regulatory assets and liabilities are regulatory balancing accounts. Sales balancing accounts accumulate differences between recorded electric utility revenue and revenue SCE is authorized to collect through rates. Cost balancing accounts accumulate differences between recorded costs and costs SCE is authorized to recover through rates. Undercollections are recorded as regulatory balancing account assets. Overcollections are recorded as regulatory balancing account liabilities. SCE's regulatory balancing accounts accumulate balances until they are refunded to or received from SCE's customers through authorized rate adjustments. Primarily all of SCE's balancing accounts can be classified as one of the following types: generation-revenue related, distribution-revenue related, generation-cost related, distribution-cost related, transmission-cost related or public purpose and other cost related.

Balancing account undercollections and overcollections accrue interest based on a three-month commercial paper rate published by the Federal Reserve. Income tax effects on all balancing account changes are deferred.

Amounts included in regulatory assets and liabilities are generally recorded with corresponding offsets to the applicable income statement accounts.

Regulatory Assets

Regulatory assets included on the consolidated balance sheets are:

In millions December 31,	2008	2007
Current:		
Regulatory balancing accounts	**$ 455**	$ 99
Energy derivatives	**138**	71
Purchased-power settlements	**—**	8
Deferred FTR proceeds	**9**	15
Other	**3**	4
	$ 605	$ 197
Long-term:		
Regulatory balancing accounts	**$ 29**	$ 15
Flow-through taxes – net	**1,337**	1,110
ARO	**224**	—
Unamortized nuclear investment – net	**375**	405
Nuclear-related ARO investment – net	**278**	297
Unamortized coal plant investment – net	**79**	94
Unamortized loss on reacquired debt	**309**	331
SFAS No. 158 pensions and other postretirement benefits	**1,882**	231
Energy derivatives	**723**	70
Environmental remediation	**40**	64
Other	**138**	104
	$ 5,414	$ 2,721
Total Regulatory Assets	**$ 6,019**	$ 2,918

SCE's regulatory assets related to energy derivatives are an offset to unrealized losses on recorded derivatives and an offset to lease accruals. SCE's regulatory assets related to purchased-power settlements were recovered through October 2008. SCE's regulatory assets related to deferred FTR proceeds represent the deferral of electric utility revenue associated with FTRs that SCE received as a transmission owner from the annual ISO FTR auction. The deferred FTR proceeds were recognized through March 2009. Based on current regulatory ratemaking and income tax laws, SCE expects to recover its net regulatory assets related to flow-through taxes over the life of the assets that give rise to the accumulated deferred income taxes. SCE's regulatory asset related to the ARO represents timing differences between the recognition of AROs in accordance with generally accepted accounting principles and the amounts recognized for rate-making purposes. SCE's nuclear-related regulatory assets related to San Onofre are expected to be recovered by 2022. SCE's nuclear-related regulatory assets related to Palo Verde are expected to be recovered by 2027. SCE's net regulatory asset related to its unamortized coal plant investment is being recovered through June 2016. SCE's net regulatory asset related to its unamortized loss on reacquired debt will be recovered over the remaining original amortization period of the reacquired debt over periods ranging from one year to 30 years. SCE's regulatory asset related to SFAS No. 158 represents the offset to the additional amounts recorded in accordance with SFAS No. 158 (see "Pension Plans and Postretirement Benefits Other Than Pensions" discussion in Note 5). This amount will be recovered through rates charged to customers. SCE's regulatory asset related to environmental remediation represents the portion of SCE's environmental liability recognized at the end of the period in excess of the amount that has been recovered through rates charged to customers. This amount will be recovered in future rates as expenditures are made.

SCE's unamortized nuclear investment – net and unamortized coal plant investment – net regulatory assets earned a 8.75% and 8.77% return in 2008 and 2007, respectively.

Regulatory Liabilities

Regulatory liabilities included on the consolidated balance sheets are:

In millions December 31,	2008	2007
Current:		
Regulatory balancing accounts	**$ 1,068**	$ 967
Rate reduction notes – transition cost overcollection	**20**	20
Energy derivatives	**6**	10
Deferred FTR costs	**13**	19
Other	**4**	3
	$ 1,111	$ 1,019
Long-term:		
Regulatory balancing accounts	**$ 43**	$ —
ARO	**—**	793
Costs of removal	**2,368**	2,230
SFAS No. 158 pensions and other postretirement benefits	**—**	308
Energy derivatives	**—**	27
Employee benefit plans	**70**	75
	$ 2,481	$ 3,433
Total Regulatory Liabilities	**$ 3,592**	$ 4,452

Rate reduction notes – transition cost overcollection represents the nonbypassable rates charged to customers subsequent to the final principal payment of SCE's rate reduction bonds. These amounts will be refunded to ratepayers. SCE's regulatory liabilities related to energy derivatives are an offset to unrealized gains on recorded derivatives and an offset to a lease prepayment. SCE's regulatory liabilities related to deferred FTR costs represent the deferral of the costs associated with FTRs that SCE purchased during the annual ISO auction process. The FTRs provide SCE with scheduling priority in certain transmission grid congestion areas in the day-ahead market. The FTRs meet the definition of a derivative instrument and are recorded at fair value and marked to market each reporting period. Any fair value change for FTRs is reflected in the deferred FTR costs regulatory liability. The deferred FTR costs are recognized as FTRs are used or expire in various periods through March 2009. SCE's regulatory liability related to the ARO represents timing differences between the recognition of AROs in accordance with generally accepted accounting principles and the amounts recognized for rate-making purposes. SCE's regulatory liabilities related to costs of removal represent electric utility revenue collected for asset removal costs that SCE expects to incur in the future. SCE's regulatory liability related to SFAS No. 158 represents the offset to the additional amounts recorded in accordance with SFAS No. 158 (see "Pension Plans and Postretirement Benefits Other Than Pensions" discussion in Note 5). This amount will be returned to ratepayers in some future rate-making proceeding. SCE's regulatory liabilities related to employee benefit plan expenses represent pension costs recovered through rates charged to customers in excess of the amounts recognized as expense or the difference between these costs calculated in accordance with rate-making methods and these costs calculated in accordance with SFAS No. 87, and PBOP costs recovered through rates charged to customers in excess of the amounts recognized as expense. These balances will be returned to ratepayers in some future rate-making proceeding, be charged against expense to the extent that future expenses exceed amounts recoverable through the rate-making process, or be applied as otherwise directed by the CPUC.

Note 12. Other Nonoperating Income and Deductions

Other nonoperating income and deductions are as follows:

In millions Year Ended December 31,	2008	2007	2006
AFUDC	**$ 54**	$ 46	$ 32
Increase in cash surrender value of life insurance policies	**24**	23	21
Performance-based incentive awards	**3**	4	19
Other	**20**	16	13
Total utility nonoperating income	**$ 101**	$ 89	$ 85
Nonutility nonoperating income	**12**	6	48
Total other nonoperating income	**$ 113**	$ 95	$ 133
Various penalties	**$ 59**	$ 5	$ 23
Civic, political and related activities and donations	**42**	35	29
Other	**22**	5	8
Total utility nonoperating deductions	**$ 123**	$ 45	$ 60
Nonutility nonoperating deductions	**2**	—	3
Total other nonoperating deductions	**$ 125**	$ 45	$ 63

In 2006, nonutility nonoperating income primarily reflects Edison Capital's $19 million pre-tax gain on the sale of certain investments, including Edison Capital's interest in an affordable housing project, the recognition at EME of an estimated business interruption insurance claim of $11 million and EME's $8 million gain related to the receipt of shares from Mirant Corporation from settlement of a claim recorded during the first quarter of 2006.

The 2008 increase in utility nonoperating deductions primarily resulted form a CPUC decision in September 2008 related to SCE incentives claimed under a CPUC-approved PBR mechanism. The decision required SCE to refund $28 million and $20 million related to customer satisfaction and employee safety reporting incentives, respectively, and further required SCE to forego claimed incentives of $20 million and $15 million related to customer satisfaction and employee safety reporting, respectively. The decision also required SCE to refund $33 million for employee bonuses related to the program and imposed a statutory penalty of $30 million. During the third quarter of 2008, SCE recorded a charge of $49 million, after-tax ($60 million, pre-tax) related to this decision.

Note 13. Jointly Owned Utility Projects

SCE owns interests in several generating stations and transmission systems for which each participant provides its own financing. SCE's proportionate share of expenses for each project is included on the consolidated statements of income.

The following is SCE's investment in each project as of December 31, 2008:

In millions	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 71	$ 13	60%
Pacific Intertie	310	103	50
Generating stations:			
Four Corners Units 4 and 5(coal)	554	454	48
Mohave (coal)	345	294	56
Palo Verde (nuclear)	1,824	1,501	16
San Onofre (nuclear)	4,833	4,024	78
Total	**$ 7,937**	**$ 6,389**	

All of Mohave and a portion of San Onofre and Palo Verde are included in regulatory assets on the consolidated balance sheets — see Note 11. Mohave ceased operations on December 31, 2005. In December 2006, SCE acquired the City of Anaheim's approximately 3% ownership interest in San Onofre Units 2 and 3.

Note 14. 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 this criterion, 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. Edison International uses VIEs to conduct its business as described below.

Description of Use of Variable Interest Entities

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 some of the 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.

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 or lease obligations by its subsidiaries and affiliates owning the operating facilities. These project level debt or lease 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 as a holding company. Distributions to EME from projects are generally only available after all current debt service or lease 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. 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.

Edison Capital, through its subsidiaries, has invested in real estate projects. These projects consist primarily of multi-family residential properties and located throughout the United States that provide affordable housing for low and moderate income households. These real estate investments qualify for various tax credits, including state and federal low-income housing tax credits, and the federal historic tax credit. With a few exceptions, the projects are managed and operated by unrelated parties and project debt is non-recourse to Edison Capital. The general partner in these entities is generally the primary beneficiary based on absorbing the majority of expected losses.

Categories of Variable Interest Entities

Projects or Entities that are Consolidated

EME has purchased a majority interest in a number of wind projects under joint development agreements with third-party developers. At December 31, 2008, EME had majority interests in 15 wind projects with a total generating capacity of 630 MW that had minority interests held by others. The projects are located in Iowa, Minnesota, New Mexico, Nebraska and Texas. Minority interest holders have key rights over matters such as budgets, incurrence of debt, and sale of the project, and in certain cases, receive a higher allocation of income and losses after a minimum return is earned by EME. In determining that EME was the primary beneficiary, a key factor was the conclusion that the power sales agreements did not constitute a variable interest since the agreements have a fixed unit price and do not absorb expected losses. As a result, the determination of EME as the primary beneficiary was based on the allocation of income and losses with EME expected to earn a majority of the expected gains or absorb the majority of the expected losses based on its ownership interest.

Consolidation of QFs —

SCE has variable interests in contracts with certain QFs that contain variable contract pricing provisions based on the price of natural gas. Four of these contracts are with entities that are partnerships owned in part by a related party, EME. These four contracts had 20-year terms at inception. The QFs sell electricity to SCE and steam to nonrelated parties. Under FIN 46(R), Edison International and SCE consolidate these four projects.

In determining that SCE was the primary beneficiary, SCE considered the term of the contract, percentage of plant capacity, pricing, and other variable interests. SCE performed a quantitative assessment which included the analysis of the expected losses and expected residual returns of the entity by using the various estimated projected cash flow scenarios associated with the assets and activities of that entity. The quantitative analysis provided sufficient evidence to determine that SCE was the primary beneficiary absorbing a majority of the entity's expected losses, receiving a majority of the entity's expected residual returns, or both.

Project	Capacity	Termination Date[1]	EME Ownership
Kern River	295 MW	June 2011	50%
Midway-Sunset	225 MW	May 2009	50%
Sycamore	300 MW	December 2007	50%
Watson	385 MW	December 2007	49%

(1) SCE's power purchase agreements with Sycamore and Watson expired on December 31, 2007. Discussions on extending the power purchase and steam agreements are underway, but no assurance can be given that such discussions will lead to extensions of these agreements. As of January 1, 2009, these projects sell power to SCE under agreements with pricing set by the CPUC.

The following table presents summarized financial information of the SCE VIEs and EME wind projects that had minority interests held by others that were consolidated at December 31, 2008:

In millions	December 31, 2008
Current assets	$ 206
Net property, plant and equipment	957
Nonutility property	282
Other long-term assets	3
Total assets	$ 1,448
Current liabilities	$ 92
Asset retirement obligation	15
Long-term obligations net of current maturities	25
Deferred revenues	15
Other long-term liabilities	18
Total liabilities	$ 165
Minority interest[(1)]	$ 268

(1) The minority interest related to SCE's VIEs takes into consideration EME's ownership in the Big 4 projects.

Assets serving as collateral for the debt obligations related to the wind projects had a carrying value of $85 million at December 31, 2008 and primarily consist of property, plant and equipment. The consolidated statement of income and cash flow includes $4 million of pre-tax income and $30 million of operating cash flow related to variable interest entities that are consolidated.

SCE's VIE projects do not have any third party debt outstanding. SCE has no investment in, nor obligation to provide support to, these entities other than its requirement to make contract payments. Any profit or loss generated by these entities will not effect SCE's income statement, except that SCE would be required to recognize losses if these projects have negative equity in the future. These losses, if any, would not affect SCE's liquidity. Any liabilities of these projects are nonrecourse to SCE.

Consolidation of Wind Development Company —

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 future development of wind projects. In accordance with FIN 46(R), EME determined that it is the primary beneficiary because it bears more than 50% of expected losses and, accordingly, EME consolidated U.S. Wind Force beginning December 15, 2006. At December 31, 2008 and 2007, the assets consolidated included $3 million and $10 million of intangible assets, respectively, primarily related to project development rights. 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.

During 2008 and 2007, EME recorded a write down of $7 million and $6 million, respectively, of capitalized costs related to U.S. Wind Force reflected in "Contract buyout/termination and other" on Edison International's consolidated statements of income.

Consolidation of Investments in Affordable Housing Projects —

Edison Capital is the primary beneficiary of one real estate project which has $1 million of debt guaranteed by a subsidiary of Edison Capital and nonrecourse debt totaling $10 million at December 31, 2008. Property serving as collateral for these loans had a carrying value of $10 million and is classified as nonutility property on the December 31, 2008 consolidated balance sheet. Edison Capital is the primary beneficiary in these entities due to the debt guarantee. Other than the guarantee, the creditors to this project do not have recourse to the general credit of Edison Capital.

Edison Capital is the primary beneficiary of eight real estate investment partnerships that were formed to syndicate Edison Capitals interests in real estate projects. In these real estate partnerships, Edison Capital has guaranteed the third party investors yield on their investments. Such guarantees are considered a variable interest and Edison Capital is considered the primary beneficiary of such investments. At December 31, 2008, the consolidated balance sheet included investments in real estate partnerships and minority interests of $14 million and $12 million, respectively, related to interests of third parties.

Projects that are not Consolidated

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 on 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.

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. 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 in which EME exercises significant influence but cannot exercise unilateral control over the operating, funding or construction activities of the project entity. Two of these projects have 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, 2008, entities which EME has accounted for under the equity method had indebtedness of $294 million, of which $128 million is proportionate to EME's ownership interest in these projects.

As of December 31, 2008, EME has five significant variable interests in projects that are not consolidated consisting of the Big 4 projects and the Sunrise project. These projects are 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 concluded that the power purchase agreements for these projects represented variable interests in the related projects and, therefore, it was not the primary beneficiary of 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 $326 million as of December 31, 2008 and is classified as investments in unconsolidated affiliates on EME's consolidated balance sheet.

As of December 31, 2008, EME has a 50% interest in the March Point project. 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. The obligations under this indemnification agreement as of December 31, 2008, if payment were required, would be $56 million, which is EME's maximum exposure to loss as EME fully impaired its equity investment in the project in 2005. EME has not recorded a liability related to the indemnity.

As of December 31, 2008, EME has an 80% interest in the Doga project located in Turkey. EME concluded that the power sales agreement which transfers ownership interest in the natural gas-fired plant to the government-owned off-taker constituted a variable interest and, consequently, EME was not the primary beneficiary.

Edison Capital has a number of investments in real estate projects that are accounted for under the equity method. Under the equity method, the project assets and related liabilities are not consolidated in Edison Capitals consolidated balance sheet. Rather, Edison Capital's financial statements reflect its investment in each entity and it records only its proportionate ownership share of net income or loss. See Note 19.

Edison Capital's maximum exposure to loss from affordable housing investments in this category is generally limited to its net investment balance of $7 million and recapture of tax credits (estimated at $36 million at December 31, 2008).

Entities with Unavailable Financial Information

SCE also has seven other contracts with QFs that contain variable pricing provisions based on the price of natural gas and are potential VIEs under FIN 46(R). SCE might be considered to be the consolidating entity under this standard. SCE continues to attempt to obtain information for these projects in order to determine whether the projects should be consolidated by SCE. These entities are not legally obligated to provide the financial information to SCE and have declined to provide any financial information to SCE. Under the grandfather scope provisions of FIN 46(R), SCE is not required to apply this rule to these entities as long as SCE continues to be unable to obtain this information. The aggregate capacity dedicated to SCE for these projects is 263 MW. SCE paid $203 million in 2008 and $180 million in both 2007 and 2006 to these projects These amounts are recoverable in utility customer rates. SCE has no exposure to loss as a result of its involvement with these projects.

Note 15. Preferred and Preference Stock of Utility Not Subject to Mandatory Redemption

SCE's authorized shares are: $100 cumulative preferred — 12 million shares, $25 cumulative preferred — 24 million shares and preference — 50 million shares. There are no dividends in arrears for the preferred stock or preference shares. Shares of SCE's preferred stock have liquidation and dividend preferences over shares of SCE's common stock and preference stock. All cumulative preferred stock is redeemable. When preferred shares are redeemed, the premiums paid, if any, are charged to common equity. No preferred stock not subject to mandatory redemption was issued or redeemed in the years ended December 31, 2008, 2007 and 2006. In January 2008, SCE repurchased 350,000 shares of 4.08% cumulative preferred stock at a price of $19.50 per share. SCE retired this preferred stock in January 2008 and recorded a $2 million gain on the cancellation of reacquired capital stock (reflected in the caption "Common stock" on the consolidated balance sheets). There is no sinking fund requirement for redemptions or repurchases of preferred stock.

Shares of SCE's preference stock rank junior to all of the preferred stock and senior to all common stock. Shares of SCE's preference stock are not convertible into shares of any other class or series of SCE's capital stock or any other security. The preference shares are noncumulative and have a $100 liquidation value. There is no sinking fund for the redemption or repurchase of the preference shares.

SCE's preferred and preference stock not subject to mandatory redemption is:

Dollars in millions, except per-share amounts	December 31,		2008	2007
	December 31,			
	Shares Outstanding	Redemption Price		
Cumulative preferred stock				
$25 par value:				
4.08% Series	650,000	$ 25.50	**$ 16**	$ 25
4.24% Series	1,200,000	$ 25.80	**30**	30
4.32% Series	1,653,429	$ 28.75	**41**	41
4.78% Series	1,296,769	$ 25.80	**33**	33
Preference stock				
No par value:				
5.349% Series A	4,000,000	$ 100.00	**400**	400
6.125% Series B	2,000,000	$ 100.00	**200**	200
6.00% Series C	2,000,000	$ 100.00	**200**	200
			920	929
Less issuance costs			**(13)**	(14)
Total			**$ 907**	$ 915

The Series A preference stock, issued in 2005, may not be redeemed prior to April 30, 2010. After April 30, 2010, SCE may, at its option, redeem the shares in whole or in part and the dividend rate may be adjusted. The Series B preference stock, issued in 2005, may not be redeemed prior to September 30, 2010. After September 30, 2010, SCE may, at its option, redeem the shares in whole or in part. The Series C preference stock, issued in 2006, may not be redeemed prior to January 31, 2011. After January 31, 2011, SCE may, at its option, redeem the shares in whole or in part. No preference stock not subject to mandatory redemption was redeemed in the last three years.

At December 31, 2008, accrued dividends related to SCE's preferred and preference stock not subject to mandatory redemption were $13 million.

Note 16. Business Segments

Edison International's reportable business segments include its electric utility operation segment (SCE), a nonutility power generation segment (EME), and a financial services and other segment (Edison Capital and EMG nonutility subsidiaries). Included in the nonutility power generation segment are the activities of MEHC, the holding company of EME. MEHC's only substantive activities were its obligations under the senior secured notes which were paid in full on June 25, 2007 as discussed in Note 3. MEHC does not have any substantive operations. Edison International evaluates performance based on net income.

SCE is a rate-regulated electric utility that supplies electric energy to a 50,000 square-mile area of central, coastal and Southern California. SCE also produces electricity. EME is engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from electric power generation facilities. EME also conducts hedging and energy trading activities in power markets open to competition. Edison Capital is a provider of financial services with investments worldwide.

On April 1, 2006, EME received, as a capital contribution from its affiliate, Edison Capital, ownership interests in a portfolio of wind projects located in Iowa and Minnesota and a small biomass project. EME accounted for this acquisition at Edison Capital's historical cost as a transaction between entities under common control. As a result of this capital contribution, Edison International's nonutility power generation segment now includes the wind assets and biomass power project previously owned by Edison Capital and included in the financial services segment.

The significant accounting policies of the segments are the same as those described in Note 1.

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 50%, 51% and 58% of nonutility power generation revenues for the years ended December 31, 2008, 2007 and 2006, 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, 2008 and 2007, EME's account receivable due from PJM was $61 million and $82 million, respectively.

EME also derived a significant source of its revenues from the sale of energy, capacity and ancillary services generated at the Illinois Plants to Commonwealth Edison under load requirements services contracts. Sales under these contracts accounted for 12% and 19% of EME's consolidated operating revenues for the years ended December 31, 2008 and 2007, respectively. Commonwealth Edison's senior unsecured debt rating are BBB- by S&P and Baa3 by Moody's. At December 31, 2008 and 2007, EME's account receivable due from Commonwealth Edison was $23 million and $20 million, respectively.

For the year ended December 31, 2008, a third customer, Constellation Energy Commodities Group, Inc. accounted for 10% of EME's consolidated operating revenues. Sales to Constellation are primarily generated from EME's merchant plants and largely consist of energy sales under forward contracts. The contract with Constellation is guaranteed by Constellation Energy Group, Inc., which has a senior unsecured debt rating of BBB by S&P and Baa3 by Moody's. At December 31, 2008, EME's account receivable due from Constellation was $22 million.

Reportable Segments Information

The following is information (including the elimination of intercompany transactions) related to Edison International's reportable segments:

In millions	Electric Utility	Nonutility Power Generation	Financial Services and Other[1]	Parent and Other[2]	Edison International
2008					
Operating revenue	$ 11,248	$ 2,811	$ 54	$ (1)	$ 14,112
Depreciation, decommissioning and amortization	1,114	194	4	1	1,313
Interest and dividend income	22	36	12	(8)	62
Equity in income (loss) from partnerships and unconsolidated subsidiaries – net	—	122	(3)	(88)	31
Interest expense – net of amounts capitalized	407	279	9	5	700
Income tax expense (benefit) – continuing operations	342	243	29	(18)	596
Income (loss) from continuing operations	683	500	60	(28)	1,215
Net income (loss)	683[2]	501	60	(29)	1,215
Total assets	32,568	9,016	3,089	(58)	44,615
Capital expenditures	2,267	552	5	—	2,824
2007					
Operating revenue	$ 10,233	$ 2,580	$ 56	$ (1)	$ 12,868
Depreciation, decommissioning and amortization	1,011	162	9	(1)	1,181
Interest and dividend income	44	98	16	(4)	154
Equity in income from partnerships and unconsolidated subsidiaries – net	—	200	28	(149)	79
Interest expense – net of amounts capitalized	429	313	10	—	752
Income tax expense (benefit) – continuing operations	337	173	(2)	(16)	492
Income (loss) from continuing operations	707	342	70	(19)	1,100
Net income (loss)	707[2]	340	70	(19)	1,098
Total assets	27,477	7,263	3,008	(225)	37,523
Capital expenditures	2,286	540	—	—	2,826
2006					
Operating revenue	$ 9,859	$ 2,239	$ 70	$ 1	$ 12,169
Depreciation, decommissioning and amortization	950	144	13	(2)	1,105
Interest and dividend income	58	98	20	(7)	169
Equity in income from partnerships and unconsolidated subsidiaries – net	—	186	29	(136)	79
Interest expense – net of amounts capitalized	399	393	16	(2)	806
Income tax expense (benefit) – continuing operations	438	145	9	(10)	582
Income (loss) from continuing operations	776	247	88	(28)	1,083
Net income (loss)	776[2]	344	88	(27)	1,181
Total assets	26,110	7,224	3,221	(294)	36,261
Capital expenditures	2,226	310	—	—	2,536

(1) Includes amounts from EMG nonutility subsidiaries that are not significant as a reportable segment.

(2) Includes amounts from Edison International (parent), other Edison International nonutility subsidiaries that are not significant as a reportable segment, as well as intercompany eliminations.

(3) Net income available for common stock.

The net income (loss) reported for nonutility power generation includes earnings from discontinued operations of less than one million for 2008, $(2) million for 2007 and $98 million for 2006.

Geographic Information

Edison International's foreign and domestic revenue and assets information is:

In millions Year Ended December 31,	2008	2007	2006
Revenue			
United States	**$ 14,067**	$ 12,816	$ 12,110
International	**45**	52	59
Total	**$ 14,112**	$ 12,868	$ 12,169

In millions December 31,	2008	2007
Assets		
United States	**$ 42,274**	$ 35,198
International	**2,341**	2,325
Assets of discontinued operations	**—**	—
Total	**$ 44,615**	$ 37,523

Note 17. Discontinued Operations

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) in 2005. EME was entitled to receive the remaining amount of the settlement after payment of creditor claims. As creditor claims were settled, EME received payments of £0.4 million (approximately $1 million) in 2008, £5 million (approximately $10 million) in 2007, and £72 million (approximately $125 million) in 2006. The after-tax income attributable to the Lakeland project was $1 million, $6 million and $85 million for 2008, 2007 and 2006, respectively. Beginning in 2002, EME reported the Lakeland project as discontinued operations and accounted for its ownership of Lakeland Power on the cost method (earnings are recognized as cash is distributed from the project).

For all years presented, the results of EME's international projects, discussed above, have been accounted for as discontinued operations on the consolidated financial statements in accordance with SFAS No. 144.

There was no revenue from discontinued operations in 2008, 2007 or 2006. The pre-tax earnings (loss) from discontinued operations were $6 million in 2008, $3 million in 2007 and $118 million in 2006.

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 right of first refusal resulted in a $3 million additional loss recorded in 2006.

There were no assets or liabilities of discontinued operations at December 31, 2008 and 2007.

Note 18. Acquisitions and Dispositions

Acquisitions

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. This project started construction in April 2006 and commenced commercial operation during April 2007. 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 on Edison International's consolidated balance sheet.

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.

Note 19. Investments in Leveraged Leases, Partnerships and Unconsolidated Subsidiaries

Leveraged Leases

Edison Capital is the lessor in various power generation, electric transmission and distribution, transportation and telecommunication leases with terms of 24 to 38 years. Each of Edison Capital's leveraged lease transactions was completed and accounted for in accordance with SFAS No. 13, "Accounting for Leases." All operating, maintenance, insurance and decommissioning costs are the responsibility of the lessees. The acquisition cost of these facilities was $6.9 billion at both December 31, 2008 and 2007. The equity investment in these facilities is generally 20% of the cost to acquire the facilities. The balance of the acquisition costs was funded by nonrecourse debt secured by first liens on the leased property. The lenders do not have recourse to Edison Capital in the event of loan default. See discussion of federal and state tax issues related to LILO/SILO leases in the "Cross-Border Lease Transactions" disclosure in Note 4.

The net income from leveraged leases is:

In millions Year Ended December 31,	2008	2007	2006
Income from leveraged leases	**$ 51**	$ 50	$ 67
Tax effect of pre-tax income:			
Current	**11**	26	41
Deferred	**(30)**	(43)	(66)
Total tax (expense) benefit	**(19)**	(17)	(25)
Net income from leveraged leases	**$ 32**	$ 33	$ 42

The net investment in leveraged leases is:

In millions December 31,	2008	2007
Rentals receivable – net	$ 3,227	$ 3,297
Estimated residual value	42	42
Unearned income	(802)	(866)
Investment in leveraged leases	2,467	2,473
Deferred income taxes	(2,313)	(2,316)
Net investment in leveraged leases	$ 154	$ 157

Rental receivables are net of principal and interest on nonrecourse debt, credit reserves and the current portion of rentals receivable. Credit reserves were $6 million and $5 million at December 31, 2008 and 2007, respectively. The current portion of rentals receivable was $32 million and $74 million at December 31, 2008 and 2007, respectively.

First Energy exercised an early buyout right under the terms of an existing lease agreement with Edison Capital related to Unit No. 2 of the Beaver Valley Nuclear Power Plant. The termination date of the lease under the early buyout option was June 1, 2008. Proceeds from the sale were $72 million. Edison Capital recorded a pre-tax gain of $41 million ($23 million after tax) during the second quarter of 2008 which is reflected in "Contract buyout/termination and other" on Edison International's consolidated statements of income.

Partnerships and Unconsolidated Subsidiaries

Edison International and its nonutility subsidiaries have equity interests primarily in energy projects, oil and gas and real estate investment partnerships.

The difference between the carrying value of these equity investments and the underlying equity in the net assets was $12 million at December 31, 2008. The difference is being amortized over the life of the energy projects.

Summarized financial information of these investments is:

In millions Year Ended December 31,	2008	2007	2006
Revenue	$ 557	$ 581	$ 707
Expenses	534	552	676
Net income	$ 23	$ 29	$ 31

In millions December 31,	2008	2007
Current assets	$ 313	$ 305
Other assets	2,508	3,187
Total assets	$ 2,821	$ 3,492
Current liabilities	$ 255	$ 190
Other liabilities	1,667	1,890
Equity	899	1,412
Total liabilities and equity	$ 2,821	$ 3,492

The undistributed earnings of equity method investments were $2 million in 2008 and $7 million in 2007.

Note 20. Quarterly Financial Data (Unaudited)

	2008				
In millions, except per-share amounts	Total	Fourth	Third	Second	First
Operating revenue	$ 14,112	$ 3,228	$ 4,295	$ 3,477	$ 3,113
Operating income	2,563	466	965	506	628
Income from continuing operations	1,215	217	433	262	304
Income (loss) from discontinued operations – net	—	—	6	(1)	(5)
Net income	1,215	217	439	261	299
Basic earnings (loss) per share:					
Continuing operations	3.69	0.66	1.31	0.79	0.92
Discontinued operations	—	—	0.02	—	(0.01)
Total	3.69	0.66	1.33	0.79	0.91
Diluted earnings (loss) per share:					
Continuing operations	3.68	0.66	1.31	0.79	0.92
Discontinued operations	—	—	0.02	—	(0.01)
Total	3.68	0.66	1.33	0.79	0.91
Dividends declared per share	1.225	0.310	0.305	0.305	0.305
Common stock prices:					
High	55.70	40.94	52.35	54.17	55.70
Low	26.73	26.73	37.86	49.14	46.81
Close	32.12	32.12	39.90	51.38	49.02

	2007				
In millions, except per-share amounts	Total	Fourth	Third	Second	First
Operating revenue	$ 12,868	$ 3,144	$ 3,900	$ 3,019	$ 2,805
Operating income	2,509	481	899	501	627
Income from continuing operations	1,100	214	465	91(1)	330
Income (loss) from discontinued operations – net	(2)	(3)	(4)	2	3
Net income	1,098	211	461	93	333
Basic earnings (loss) per share:					
Continuing operations	3.34	0.65	1.41	0.28	1.00
Discontinued operations	(0.01)	(0.01)	(0.01)	0.01	0.01
Total	3.33	0.64	1.40	0.29	1.01
Diluted earnings (loss) per share:					
Continuing operations	3.32	0.65	1.40	0.28	1.00
Discontinued operations	(0.01)	(0.01)	(0.01)	—	0.01
Total	3.31	0.64	1.39	0.28	1.01
Dividends declared per share	1.175	0.305	0.29	0.29	0.29
Common stock prices:					
High	60.26	58.55	59.57	60.26	51.00
Low	42.76	53.14	50.64	49.13	42.76
Close	53.37	53.37	55.45	56.12	49.13

As a result of rounding, the total of the four quarters does not always equal the amount for the year.

(1) Reflects a $241 million pre-tax ($148 million after tax) loss on early extinguishment of debt.

Selected Financial Data: 2004 – 2008 Edison International

Dollars in millions, except per-share amounts	2008	2007	2006	2005	2004
Edison International and Subsidiaries					
Operating revenue	**$ 14,112**	$ 12,868	$ 12,169	$ 11,417	$ 10,242
Operating expenses	**$ 11,549**	$ 10,359	$ 9,680	$ 9,102	$ 9,147
Income from continuing operations	**$ 1,215**	$ 1,100	$ 1,083	$ 1,108	$ 226
Net income	**$ 1,215**	$ 1,098	$ 1,181	$ 1,137	$ 916
Weighted-average shares of common stock outstanding (in millions)	**326**	326	326	326	326
Basic earnings (loss) per share:					
Continuing operations	**$ 3.69**	$ 3.34	$ 3.28	$ 3.38	$ 0.69
Discontinued operations	**$ —**	$ (0.01)	$ 0.30	$ 0.09	$ 2.12
Total	**$ 3.69**	$ 3.33	$ 3.58	$ 3.47	$ 2.81
Diluted earnings per share	**$ 3.68**	$ 3.31	$ 3.57	$ 3.45	$ 2.77
Dividends declared per share	**$ 1.225**	$ 1.175	$ 1.10	$ 1.02	$ 0.85
Book value per share at year-end	**$ 29.21**	$ 25.92	$ 23.66	$ 20.30	$ 18.56
Market value per share at year-end	**$ 32.12**	$ 53.37	$ 45.48	$ 43.61	$ 32.03
Rate of return on common equity	**13.7%**	13.6%	16.5%	18.1%	17.1%
Price/earnings ratio	**8.7**	16.0	12.7	12.6	11.4
Ratio of earnings to fixed charges	**2.73**	2.45	2.48	2.49	1.11
Total assets	**$ 44,615**	$ 37,523	$ 36,261	$ 34,791	$ 33,269
Long-term debt	**$ 10,950**	$ 9,016	$ 9,101	$ 8,833	$ 9,678
Preferred and preference stock of utility not subject to mandatory redemption	**$ 907**	$ 915	$ 915	$ 729	$ 129
Common shareholders' equity	**$ 9,517**	$ 8,444	$ 7,709	$ 6,615	$ 6,049
Preferred stock subject to mandatory redemption	**$ —**	$ —	$ —	$ —	$ 139
Retained earnings	**$ 7,078**	$ 6,311	$ 5,551	$ 4,798	$ 4,078
Southern California Edison Company					
Operating revenue	**$ 11,248**	$ 10,233	$ 9,859	$ 9,065	$ 8,491
Net income available for common stock	**$ 683**	$ 707	$ 776	$ 725	$ 915
Basic earnings per Edison International common share	**$ 2.10**	$ 2.17	$ 2.38	$ 2.22	$ 2.81
Total assets	**$ 32,568**	$ 27,477	$ 26,110	$ 24,703	$ 23,290
Rate of return on common equity	**10.7%**	12.0%	15.0%	15.3%	21.0%
Edison Mission Energy					
Revenue	**$ 2,811**	$ 2,580	$ 2,239	$ 2,265	$ 1,653
Income (loss) from continuing operations	**$ 500**	$ 416	$ 316	$ 414	$ (560)
Net income (loss)	**$ 501**	$ 414	$ 414	$ 442	$ 130
Total assets	**$ 9,080**	$ 7,272	$ 7,235	$ 6,655	$ 7,081
Rate of return on common equity	**21.7%**	18.4%	18.4%	24.2%	7.0%
Edison Capital					
Revenue	**$ 58**	$ 56	$ 73	$ 77	$ 87
Net income	**$ 58**	$ 69	$ 89	$ 81	$ 52
Total assets	**$ 3,033**	$ 2,977	$ 3,199	$ 3,376	$ 3,279
Rate of return on common equity	**14.2%**	15.6%	9.6%	12.3%	8.1%

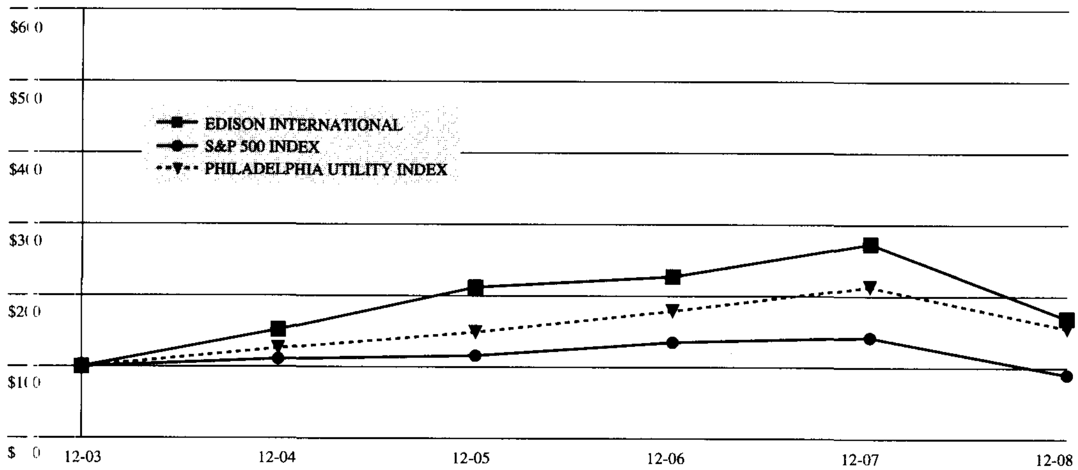
The selected financial data was derived from Edison International's audited financial statements and is qualified in its entirety by the more detailed information and financial statements, including notes to these financial statements, included in this annual report. Prior to 2007, the above table included MEHC. Because MEHC paid off its long-term debt in 2007, it no longer files with the SEC. Therefore, beginning with 2007, the above table includes Edison Mission Energy data. Amounts presented in this table have been revised to reflect Edison Capital's capital contribution to MEHC. See Note 16 for further discussion. During 2004, EME sold 11 international projects.

Amounts presented in this table have been revised to reflect continuing operations unless stated otherwise. See Note 17, Discontinued Operations, for further discussion.

Edison International *Leading the Way in Electricity*[SM]

Edison International, through its subsidiaries, is a generator and distributor of electric power and an investor in infrastructure and energy assets, including renewable energy. Headquartered in Rosemead, California, Edison International is the parent company of Southern California Edison, one of the nation's largest electric utilities, and Edison Mission Group, a competitive power generation business and parent company to Edison Mission Energy and Edison Capital.

Comparison of Five-Year Cumulative Total Return



	12/03	12/04	12/05	12/06	12/07	12/08
Edison International	100	152	212	227	273	169
S & P 500 Index	100	111	116	135	142	90
Philadelphia Utility Index	100	126	149	179	213	155

Note: Assumes $100 invested on December 31, 2003 in stock or index including reinvestment of dividends. Performance of the Philadelphia Utility Index is regularly reviewed by management and the Board of Directors in understanding Edison International's relative performance and is used in conjunction with elements of the company's incentive compensation program.

Southern California Edison Company

Alan J. Fohrer
Chairman of the Board and
Chief Executive Officer

John R. Fielder
President

Pedro J. Pizarro
Executive Vice President,
Power Operations

Bruce C. Foster
Senior Vice President,
Regulatory Affairs

Cecil R. House
Senior Vice President,
Safety, Operations Support and
Chief Procurement Officer

James A. Kelly
Senior Vice President,
Transmission and Distribution

Thomas M. Noonan
Senior Vice President and
Chief Financial Officer

Stephen E. Pickett
Senior Vice President and
General Counsel

Ross T. Ridenoure
Senior Vice President and
Chief Nuclear Officer

Mahvash Yazdi
Senior Vice President,
Business Integration and
Chief Information Officer

Lynda L. Ziegler
Senior Vice President,
Customer Service

Robert C. Boada
Vice President and Treasurer

Lisa D. Cagnolatti
Vice President,
Business Customer Division

Kevin R. Cini
Vice President,
Energy Supply and Management

Ann P. Cohn
Vice President and
Associate General Counsel

Paul J. De Martini
Vice President,
Advanced Technology

Erwin G. Furukawa
Vice President,
Customer Programs and Services

Stuart R. Hemphill
Vice President,
Renewable and
Alternative Power

Harry B. Hutchison
Vice President,
Customer Service Operations

Akbar Jazayeri
Vice President,
Regulatory Operations

Walter J. Johnston
Vice President,
Power Delivery

R. W. (Russ) Krieger, Jr.
Vice President,
Power Production

Barbara E. Mathews
Vice President,
Associate General Counsel,
Chief Governance Officer and
Corporate Secretary

David L. Mead
Vice President,
Engineering and
Technical Services

Kevin M. Payne
Vice President,
Enterprise Resource Planning

Frank J. Quevedo
Vice President,
Equal Opportunity

Megan Scott-Kakures
Vice President and General Auditor

Michael P. Short
Vice President,
Nuclear Engineering and
Technical Services

Leslie E. Starck
Vice President,
Local Public Affairs

Kenneth S. Stewart
Vice President and
Chief Ethics and Compliance Officer

Linda G. Sullivan
Vice President and Controller

Edison Mission Group*

Ronald L. Litzinger
Chairman of the Board,
President and Chief Executive Officer

John P. Finneran, Jr.
Senior Vice President and
Chief Financial Officer

Steven D. Eisenberg
Senior Vice President and
General Counsel

Guy F. Gorney
Senior Vice President,
Generation

Paul Jacob
Senior Vice President,
Marketing and Trading

Gerard P. Loughman
Senior Vice President,
Development

Douglas R. McFarlan
Senior Vice President,
Public Affairs and
Communications

Jenene J. Wilson
Vice President,
Human Resources

**Parent company of Edison Mission Energy and Edison Capital*

Theodore F. Craver, Jr.[3]
Chairman of the Board,
President and
Chief Executive Officer,
Edison International
A director since 2007

Vanessa C.L. Chang[1,4]
Principal,
EL & EL Investments
(private real estate investment company)
Los Angeles, California
A director since 2007

France A. Córdova[4,5]
President,
Purdue University
West Lafayette, Indiana
A director since 2004

Charles B. Curtis[4,5]
President and Chief Operating Officer,
Nuclear Threat Initiative
(private foundation dealing with national security issues)
Washington, DC
A director since 2006

Bradford M. Freeman[1,2,3]
Founding Partner,
Freeman Spogli & Co.
(private investment company)
Los Angeles, California
A director since 2002

Luis G. Nogales[1,4]
Managing Partner,
Nogales Investors, LLC
(private equity investment company)
Los Angeles, California
A director since 1993

Ronald L. Olson[3,4]
Senior Partner,
Munger, Tolles & Olson (law firm)
Los Angeles, California
A director since 1995

James M. Rosser[2,3,5]
President,
California State University, Los Angeles
Los Angeles, California
A director since 1988

Richard T. Schlosberg, III[1,2,5]
Retired President and
Chief Executive Officer,
The David and Lucile Packard Foundation
(private family foundation)
San Antonio, Texas
A director since 2002

Thomas C. Sutton[1,2,3]
Retired Chairman of the Board and
Chief Executive Officer,
Pacific Life Insurance Company
Newport Beach, California
A director since 1995

Brett White[2,5]
President and
Chief Executive Officer,
CB Richard Ellis
(commercial real estate services company)
A director since 2007

1 Audit Committee
2 Compensation and Executive Personnel Committee
3 Executive Committee
4 Finance Committee
5 Nominating/Corporate Governance Committee

Edison International

Theodore F. Craver, Jr.
Chairman of the Board,
President and
Chief Executive Officer

Robert L. Adler
Executive Vice President and
General Counsel

Polly L. Gault
Executive Vice President,
Public Affairs

W. James Scilacci
Executive Vice President,
Chief Financial Officer and
Treasurer

Diane L. Featherstone
Senior Vice President,
Human Resources

Barbara J. Parsky
Senior Vice President,
Corporate Communications

Jeffrey L. Barnett
Vice President,
Tax

Scott S. Cunningham
Vice President,
Investor Relations

Andrew J. Hertneky
Vice President,
Strategic Planning

Barbara E. Mathews
Vice President,
Associate General Counsel,
Chief Governance Officer and
Corporate Secretary

Megan Scott-Kakures
Vice President and
General Auditor

Kenneth S. Stewart
Vice President and
Chief Ethics and Compliance Officer

Linda G. Sullivan
Vice President and Controller

Annual Meeting

The annual meeting of shareholders will be held on Thursday, April 23, 2009, at 9:00 a.m., Pacific Time, at the Hilton Los Angeles San Gabriel Hotel, 225 West Valley Boulevard, San Gabriel, California 91776.

Corporate Governance Practices

A description of Edison International's corporate governance practices is available on our Web site at www.edisoninvestor.com. The Edison International Board Nominating/ Corporate Governance Committee periodically reviews the Company's corporate governance practices and makes recommendations to the Company's Board that the practices be updated from time to time.

Stock Listing and Trading Informational Common Stock

The New York Stock Exchange uses the ticker symbol EIX; daily newspapers list the stock as EdisonInt.

Transfer Agent and Registrar

Wells Fargo Bank, N.A., which maintains shareholder records, is the transfer agent and registrar for Edison International's common stock and Southern California Edison Company's preferred and preference stock. Shareholders may call Wells Fargo Shareowner Services, (800) 347-8625, between 7 a.m. and 7 p.m. (Central Time), Monday through Friday, to speak with a representative (or to use the interactive voice response unit 24 hours a day, seven days a week) regarding:

- stock transfer and name-change requirements;
- address changes, including dividend payment addresses;
- electronic deposit of dividends;
- taxpayer identification number submissions or changes;
- duplicate 1099 and W-9 forms; notices of, and replacement of, lost or destroyed stock certificates and dividend checks;
- Edison International's Dividend Reinvestment and Direct Stock Purchase Plan, including enrollments, purchases, withdrawals, terminations, transfers, sales, duplicate statements, and direct debit of optional cash for dividend reinvestment; and requests for access to online account information.

Inquiries may also be directed to:

Wells Fargo Bank, N.A.
Shareowner Services Department
161 North Concord Exchange Street
South St. Paul, MN 55075-1139

Fax:
(651) 450-4033

Wells Fargo Shareowner Services℠
www.wellsfargo.com/
shareownerservices

Web Address
www.edisoninvestor.com

Online account information:
www.shareowneronline.com

Dividend Reinvestment and Direct Stock Purchase Plan

A prospectus and enrollment forms for Edison International's common stock Dividend Reinvestment and Direct Stock Purchase Plan are available from Wells Fargo Shareowner Services upon request.

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Rosemead, California 91770
www.edison.com