EDISON INTERNATIONAL
Form 10-K
February 29, 2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

R ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2011

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File Number 1-9936

EDISON INTERNATIONAL
(Exact name of registrant as specified in its charter)

California (State or other jurisdiction of incorporation or organization)	95-4137452 (I.R.S. Employer Identification No.)
2244 Walnut Grove Avenue (P.O. Box 976) Rosemead, California (Address of principal executive offices)	91770 (Zip Code)

(626) 302-2222
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, no par value	NYSE

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes o No þ

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check One):

Large Accelerated Filer þ	Accelerated Filer o	Non-accelerated Filer o	Smaller Reporting Company o

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

The aggregate market value of registrant's voting stock held by non-affiliates was approximately $12.6 billion on or about June 30, 2011, based upon prices reported on the New York Stock Exchange. As of February 27, 2012, there were 325,811,206 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the following documents listed below have been incorporated by reference into the parts of this report so indicated.

(1) Designated portions of the Proxy Statement relating to registrant's 2012 Annual Meeting of Shareholders
Part III

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GLOSSARY

The following terms and abbreviations appearing in the text of this report have the meanings indicated below.

2011 Form 10-K	Edison International's Annual Report on Form 10-K for the year-ended December 31, 2011
2010 Tax Relief Act	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
AFUDC	allowance for funds used during construction
Ambit project	American Bituminous Power Partners, L.P.
AOI	Adjusted Operating Income (Loss)
APS	Arizona Public Service Company
ARO(s)	asset retirement obligation(s)
BACT	best available control technology
BART	best available retrofit technology
Bcf	billion cubic feet
Big 4	Kern River, Midway-Sunset, Sycamore and Watson natural gas power projects
Btu	British thermal units
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CAMR	Clean Air Mercury Rule
CARB	California Air Resources Board
CDWR	California Department of Water Resources
CEC	California Energy Commission
coal plants	Midwest Generation coal plants and Homer City plant
Commonwealth Edison	Commonwealth Edison Company
CPS	Combined Pollutant Standard
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CRRs	congestion revenue rights
DOE	U.S. Department of Energy
EME	Edison Mission Energy
EMG	Edison Mission Group Inc.
EMMT	Edison Mission Marketing & Trading, Inc.
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
FGIC	Financial Guarantee Insurance Company
FIP(s)	federal implementation plan(s)
Four Corners	coal fueled electric generating facility located in Farmington, New Mexico in which SCE holds a 48% ownership interest
GAAP	generally accepted accounting principles
GHG	greenhouse gas
Global Settlement	A settlement between Edison International and the IRS that resolved federal tax disputes related to Edison Capital's cross-border, leveraged leases through 2009, and all other outstanding federal tax disputes and affirmative claims for tax years 1986 through 2002 and related matters with state tax authorities.

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GRC	general rate case
GWh	gigawatt-hours
Homer City	EME Homer City Generation L.P., a Pennsylvania limited partnership that leases and operates three coal-fired electric generating units and related facilities located in Indiana County, Pennsylvania
Illinois EPA	Illinois Environmental Protection Agency
IRS	Internal Revenue Service
ISO	Independent System Operator
kWh(s)	kilowatt-hour(s)
LIBOR	London Interbank Offered Rate
MATS	Mercury and Air Toxics Standards
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations in this report
Midwest Generation	Midwest Generation, LLC, a Delaware limited liability company that owns and/or leases, and that operates, the Midwest Generation plants
Midwest Generation plants	Midwest Generation's power plants (fossil fuel) located in Illinois
MMBtu	million British thermal units
Mohave	two coal fueled electric generating facilities that no longer operate located in Clark County, Nevada in which SCE holds a 56% ownership interest
Moody's	Moody's Investors Service
MRTU	Market Redesign and Technology Upgrade
MW	megawatts
MWh	megawatt-hours
NAAQS	national ambient air quality standards
NAPP	Northern Appalachian
NERC	North American Electric Reliability Corporation
Ninth Circuit	U.S. Court of Appeals for the Ninth Circuit
NOV	notice of violation
NOx	nitrogen oxide
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NYISO	New York Independent System Operator
PADEP	Pennsylvania Department of Environmental Protection
Palo Verde	large pressurized water nuclear electric generating facility located near Phoenix, Arizona in which SCE holds a 15.8% ownership interest
PBOP(s)	postretirement benefits other than pension(s)
PBR	performance-based ratemaking
PG&E	Pacific Gas & Electric Company
PJM	PJM Interconnection, LLC
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
QF(s)	qualifying facility(ies)
ROE	return on equity
RPM	Reliability Pricing Model
RTO(s)	Regional Transmission Organization(s)
S&P	Standard & Poor's Ratings Services
San Onofre	large pressurized water nuclear electric generating facility located in south San Clemente, California in which SCE holds a 78.21% ownership interest

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SCE	Southern California Edison Company
SNCR	selective non-catalytic reduction
SDG&E	San Diego Gas & Electric
SEC	U.S. Securities and Exchange Commission
SIP(s)	state implementation plan(s)
SO_2	sulfur dioxide
US EPA	U.S. Environmental Protection Agency
VIE(s)	variable interest entity(ies)

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FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. 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 from those currently expected, or that otherwise could impact Edison International, include, but are not limited to:

- cost of capital and the ability of Edison International or its subsidiaries to borrow funds and access the capital markets on reasonable terms;
- environmental laws and regulations, at both state and federal levels, or changes in the application of those laws, that could require additional expenditures or otherwise affect the cost and manner of doing business, including compliance with CPS at Midwest Generation and the CSAPR and the MATS rule at Midwest Generation and Homer City;
- 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;
- possible customer bypass or departure due to technological advancements or cumulative rate impacts that make self-generation or use of alternative energy sources economically viable;
- risks associated with the operation of transmission and distribution assets and nuclear and other power generating facilities including: nuclear fuel storage issues, public safety issues, failure, availability, efficiency, output, cost of repairs and retrofits of equipment and availability and cost of spare parts;
- cost and availability of electricity, including 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;
- changes in interest rates and rates of inflation, including those rates which may be adjusted by public utility regulators;
- governmental, statutory, regulatory or administrative changes or initiatives affecting the electricity industry, including the market structure rules applicable to each market and price mitigation strategies adopted by Independent System Operators and Regional Transmission Organizations;
- 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;
- cost and availability of labor, equipment and materials;
- 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;
- ability to recover uninsured losses in connection with wildfire-related liability;
- effects of legal proceedings, changes in or interpretations of tax laws, rates or policies, and changes in accounting standards;
- potential for penalties or disallowances caused by non-compliance with applicable laws and regulations;
- cost and availability of coal, natural gas, fuel oil, and nuclear fuel, and related transportation to the extent not recovered through regulated rate cost escalation provisions or balancing accounts;

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- 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;
- ability to provide sufficient collateral in support of hedging activities and power and fuel purchased;
- risks inherent in the development of generation projects and transmission and distribution infrastructure replacement and expansion projects, including those related to project site identification, public opposition, environmental mitigation, construction, permitting, power curtailment costs (payments due under power contracts in the event there is insufficient transmission to enable the acceptance of power delivery), and governmental approvals;
- risks that competing transmission systems will be built by merchant transmission providers in SCE's service area; and
- weather conditions and natural disasters.

See "Risk Factors" in Part I, Item 1A of this report for additional information on risks and uncertainties that could cause results to differ from those currently expected or that otherwise could impact Edison International or its subsidiaries.

Additional information about risks and uncertainties, including more detail about the factors described in this report, is contained throughout this report. 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 U.S. Securities and Exchange Commission.

Except when otherwise stated, 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.

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PART I
ITEM 1. BUSINESS
INTRODUCTION

Edison International was incorporated on April 20, 1987, under the laws of the State of California for the purpose of becoming the parent holding company of Southern California Edison Company ("SCE"), a California public utility corporation and Edison Mission Group Inc. ("EMG"), a competitive power generation company. As a holding company, Edison International's progress and outlook are dependent on developments at its operating subsidiaries.

At December 31, 2011, Edison International and its subsidiaries had an aggregate of 19,930 full-time employees. The principal executive offices of Edison International are located at 2244 Walnut Grove Avenue, P.O. Box 976, Rosemead, California 91770, and the telephone number is (626) 302-2222.

Edison International makes available on its investor website, www.edisoninvestor.com, its Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, Proxy Statement and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act, as soon as reasonably practicable after Edison International electronically files such material with, or furnishes it to, the SEC. Such reports are also available on the SEC's internet website at www.sec.gov. The information contained on, or connected to, the Edison investor website is not incorporated by reference into this report.

Subsidiaries of Edison International

Edison International has two business segments for financial reporting purposes: an electric utility segment (SCE) and a competitive power generation segment (EMG).

SCE is an investor-owned public utility primarily engaged in the business of supplying electricity to an approximately 50,000 square-mile area of southern California. The SCE service territory contains a population of nearly 14 million people. In 2011, SCE's total operating revenue was derived as follows: 41.6% commercial customers, 40.2% residential customers, 5.7% industrial customers, 0.7% resale sales, 5.5% public authorities, and 6.3% agricultural and other customers. SCE had 18,069 full-time employees at December 31, 2011. SCE's operating revenue was approximately $10.6 billion in 2011.

Sources of energy to serve SCE's customers during 2011 were approximately: 36% purchased power; 21% CDWR; and 43% SCE-owned generation.

SCE separately files reports pursuant to Section 13(a) or 15(d) of the Securities Exchange Act. SCE also files a joint Proxy Statement with its parent, Edison International. Such reports and Proxy Statement are available at www.edisoninvestor.com or on the SEC's website at www.sec.gov. The information contained on, or connected to, the Edison investor website is not incorporated by reference into this report.

EMG is the holding company for its principal wholly owned subsidiary, EME. EME is also a holding company with subsidiaries and affiliates engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from independent power production facilities. Some of the facilities are operated on a merchant basis, with energy being sold into the marketplace, and others are operated under contracts calling for the delivery of energy to specific purchasers. EME also engages in hedging and energy trading activities in competitive power markets through its Edison Mission Marketing & Trading, Inc. ("EMMT") subsidiary. At December 31, 2011, EMG and its subsidiaries employed 1,795 people. EMG's consolidated operating revenue was approximately $2.2 billion in 2011.

EMG's subsidiaries or affiliates have typically been formed to own full or partial interests in one or more power generation facilities and ancillary facilities, with each plant or group of related plants being individually referred to by EMG as a project. EMG's operating projects primarily consist of coal-fired and natural gas-fired generating facilities, and renewable energy facilities, primarily wind projects. As of December 31, 2011, EMG's subsidiaries and affiliates owned or leased interests in 43 operating projects with an aggregate net physical capacity of 11,504 MW of which EME's pro rata share was 10,379 MW. At December 31, 2011, EME's subsidiaries and affiliates also had one wind project and one natural gas-fired peaker plant under construction, totaling 80 MW and 479 MW, respectively of net generating capacity.

EME separately files reports pursuant to Section 13(a) or 15(d) of the Securities Exchange Act. Such reports are available at www.edisoninvestor.com or on the SEC's internet website at www.sec.gov. The information contained on, or connected to, the Edison investor website is not incorporated by reference into this report.
Edison International maintains a property and casualty insurance program for itself and its subsidiaries, which includes

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business interruption (for EMG only), and excess liability insurance covering liabilities to third parties for bodily injury or property damage resulting from operations. These policies are subject to specific retentions, sublimits and deductibles, which are comparable to those carried by other utility and electric generating companies of similar size. SCE also has separate insurance programs for nuclear property and liability, workers compensation and solar rooftop construction. EMG maintains a separate wind liability insurance program for its wind projects. For further information on wildfire insurance, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies."

Regulation of Edison International and Subsidiaries

Edison International and its subsidiaries are subject to extensive regulation. As a public utility holding company, Edison International is subject to the Public Utility Holding Company Act. The Public Utility Holding Company Act primarily obligates Edison International and its utility subsidiaries to provide access to their books and records to the FERC and the CPUC for ratemaking purposes.

Edison International is not a public utility. The 1988 CPUC decision authorizing SCE to reorganize into a holding company structure, however, contains certain obligations on Edison International and its affiliates. These include a requirement that SCE's dividend policy shall continue to be established by SCE's Board of Directors as though SCE were a stand-alone utility company, and that the capital requirements of SCE, as deemed to be necessary to meet SCE's service obligations, shall receive first priority from the Boards of Directors of Edison International and SCE. The CPUC has also promulgated Affiliate Transaction Rules, which, among other requirements, prohibit holding companies from (1) being used as a conduit to provide non-public information to a utility's affiliate and (2) causing or abetting a utility's violation of the rules, including providing preferential treatment to affiliates.

SOUTHERN CALIFORNIA EDISON COMPANY

Regulation

CPUC

SCE's retail operations are subject to regulation by the CPUC. The CPUC has the authority to regulate, among other things, retail rates, energy purchases on behalf of retail customers, rate of return, rates of depreciation, issuance of securities, disposition of utility assets and facilities, oversight of nuclear decommissioning funding and costs, and aspects of the transmission system planning, site identification and construction.

FERC

SCE's wholesale operations (including sales of electricity into the wholesale markets) are subject to regulation by the FERC. The FERC has the authority to regulate wholesale rates as well as other matters, including unbundled transmission service pricing, accounting practices, and licensing of hydroelectric projects. The FERC also has jurisdiction over a portion of the retail rates and associated rate design.

NERC

The North American Electric Reliability Corporation ("NERC") establishes and enforces reliability standards and critical infrastructure protection standards to protect the bulk power system against potential disruptions from cyber and physical security breaches. The critical infrastructure protection standards focus on controlling access to critical physical and cyber security assets. Compliance with these standards is mandatory. The maximum penalty that may be levied for violating a NERC reliability or critical infrastructure protection standard is $1 million per violation, per day. SCE has a formal cyber security program that is staffed and has a dedicated budget. The program covers SCE's information technology systems as well as the electric grid where SCE has control of it. Program staff is engaged with industry groups as well as public-private initiatives to reduce risk and to strengthen the security and reliability of SCE's systems and infrastructure. The program is also engaged in the protection of SCE's customer information.

Transmission and Substation Facilities Regulation

The construction, planning and project site identification of SCE's transmission lines and substation facilities require the approval of many governmental agencies and compliance with various laws. These agencies include utility regulatory commissions such as the CPUC and other state regulatory agencies depending on the project location; the CAISO, and other environmental, land management and resource agencies such as the Bureau of Land Management, the U.S. Forest Service, and the California Department of Fish and Game; and regional water quality control boards. In addition, to the extent that

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SCE transmission line projects pass through lands owned or controlled by Native American tribes, consent and approval from the affected tribes and the Bureau of Indian Affairs are also necessary for the project to proceed.

CEC

The construction, planning, and project site identification of SCE's power plants of 50 MW or greater within California are subject to the jurisdiction of the CEC. The CEC is also responsible for forecasting future energy needs. These forecasts are used by the CPUC in determining the adequacy of SCE's electricity procurement plans.

Nuclear Power Plant Regulation

SCE is subject to the jurisdiction of the NRC with respect to the safety of its San Onofre and Palo Verde Nuclear Generating Stations. The NRC regulates commercial nuclear power plants through licensing, oversight and inspection, performance assessment, and enforcement of its requirements.

In light of the events at the Fukushima Daiichi nuclear plant in Japan resulting from the March 2011 earthquake and tsunami, the NRC has been performing and plans to continue to perform additional operational and safety reviews of nuclear facilities in the United States. The NRC's Near Term Task Force ("NTTF") conducted a systematic review of NRC processes and regulations to determine whether additional improvements to the existing nuclear regulatory system are warranted in light of the events in Japan. The NTTF concluded that a sequence of events like the Fukushima accident is unlikely to occur in the U.S., and that continued operation of U.S. reactors does not pose an imminent risk to public health and safety. The NTTF Report proposed changes to regulations applicable to protection against natural phenomena, including earthquakes and flooding and emergency preparedness, and the NTTF made a number of recommendations as to actions that the NRC might implement. In October 2011, the NRC identified seven of the near-term actions recommended by the NRC staff as having the greatest potential for safety improvement. The NRC staff was directed to strive to implement these actions by 2016. Implementation of these actions will require further interactions between the NRC staff and the nuclear industry. These actions may impact future operations and capital requirements at U.S. nuclear facilities at the time of their implementation, including the operations and capital requirements of SCE's nuclear facilities.

Operating License Renewal

In April 2011, the NRC extended the operating license for Palo Verde Operating Units 1, 2 and 3 for an additional 20 years, to 2045, 2046 and 2047, respectively. San Onofre's current operating licenses for Units 2 and 3 will expire in 2022. The NRC's review of a license renewal application typically takes three to five years. Prior to filing a license renewal application at the NRC, SCE would make an application to the CPUC to demonstrate the cost effectiveness of continuing operations at San Onofre and to seek authority to recover the cost of seeking a license renewal at the NRC and pursuing approvals from other state and federal agencies, such as the Department of the Navy and the California Coastal Commission. SCE will consider a decision to file an application for cost recovery at the CPUC in 2012. If SCE were to choose not to pursue license renewal or if SCE' efforts to obtain license renewal were not successful, SCE will need to determine what generation and transmission alternatives would need to be made available to replace the capacity, energy, and grid reliability benefits that SCE's customers now receive from San Onofre by the time San Onofre ceases generating electricity. Should SCE decide to pursue a license extension for San Onofre, SCE will likely need to simultaneously consider generation and transmission alternatives given the long lead times for the NRC to approve a license extension and to site, permit and construct new generation and transmission facilities. The costs of these alternatives could be substantial.

Overview of Ratemaking Process

CPUC

Revenue authorized by the CPUC through triennial GRC proceedings is intended to provide SCE a reasonable opportunity to recover its costs and earn a return on its net investment in generation and distribution assets (also referred to as “rate base”). The CPUC sets an annual revenue requirement for the base year which is made up of the operation and maintenance costs, depreciation, taxes and a return consistent with the capital structure (discussed below). The return is established by multiplying an authorized rate of return, determined in separate cost of capital proceedings, by SCE's generation and distribution rate base. In the GRC proceedings, the CPUC also generally approves the level of capital spending on a forecast basis. Following the base year, the revenue requirements for the remaining two years are set by a methodology established in the GRC proceeding, which generally, among other items, includes annual allowances for escalation in operation and maintenance costs, additional changes in capital-related investments and the recovery for expected nuclear refueling outages.

SCE's authorized revenue requirements were $4.83 billion, $5.04 billion and $5.25 billion for the years ended December 31, 2009, 2010 and 2011, respectively. SCE filed its 2012 GRC application with the CPUC on November 23, 2010, to be

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effective on January 1, 2012. For further discussion of the 2012 GRC, see "Edison International Overview—Management Overview of SCE—2012 CPUC General Rate Case" in the MD&A.

CPUC rates decouple authorized revenue from the volume of electricity sales, so that SCE earns revenue equal to amounts authorized. Differences between amounts collected and authorized levels are either collected from or refunded to customers, and, therefore, such differences do not impact operating revenue. Accordingly, SCE is neither benefited nor burdened by the volumetric risk related to retail electricity sales.

The CPUC regulates SCE's capital structure and authorized rate of return. SCE's current authorized capital structure is 48% common equity, 43% long-term debt and 9% preferred equity. SCE's current authorized cost of capital consists of: cost of long-term debt of 6.22%, cost of preferred equity of 6.01% and return on common equity of 11.5%. SCE is scheduled to file a new cost of capital application with the CPUC in April 2012 that will be effective beginning in 2013.

In addition, to the ratemaking process described above, the CPUC has also authorized ratemaking mechanisms outside of the GRC process for significant capital projects, as needed.

Balancing accounts (also referred to as cost-recovery mechanisms) are typically used to track and recover SCE's costs of fuel, purchased-power, and certain operation and maintenance expenses, including certain demand-side management program costs. SCE earns no return on these activities and although differences between forecasted and actual costs do not impact earnings, such differences do impact cash flows and can change rapidly.

SCE's balancing account for fuel and power procurement-related costs is established under the Energy Resource Recovery Account ("ERRA") Mechanism. SCE sets rates based on an annual forecast of the costs that it expects to incur during the following year. In addition, the CPUC has established a "trigger" mechanism for the ERRA balancing account that allows for a rate adjustment if the balancing account over-collection or under-collection exceeds 5% of SCE's prior year's revenue that is classified as generation for retail rates. For 2012, the trigger amount is approximately $237 million.

The majority of costs eligible for recovery through cost-recovery rates are approved upfront by the CPUC though a procurement plan with predefined standards, or through CPUC preapproval, and thus could negatively impact earnings and cash flows if SCE's costs were found to be unreasonable or out of compliance and disallowed.

FERC

Revenue authorized by the FERC is intended to provide SCE a reasonable opportunity to recover its costs and earn a return on its net investment in transmission assets. In August 2011, the FERC accepted SCE's request to implement a formula rate effective January 1, 2012 to determine SCE's FERC transmission revenue requirement, including its construction work in progress ("CWIP") revenue requirement that was previously recovered through a separate mechanism. For further discussion of SCE's FERC formula rates, see "Edison International Overview—Management Overview of SCE—FERC Formula Rates" in the MD&A.

Retail Rates

To develop retail rates, the authorized revenue requirements are allocated among all customer classes (residential, commercial, industrial and agricultural) on a functional basis (i.e., generation, distribution, transmission, etc.). Specific rate components are designed to recover the authorized revenue allocated to each customer class.

Currently, SCE has a five tier residential rate structure. Each tier represents a certain electricity usage level and within each increasing usage level, the electricity is priced at higher rates per kilowatt hour. The first tier is a baseline tier and has the lowest rate per kilowatt hour. "Baseline" refers to a specific amount of energy allocated for residential customers that is charged at a lower price than energy used in excess of that amount. Baseline quantities are determined by SCE for approval by the CPUC using average residential electricity consumption for nine geographical regions in southern and central California. Seasonal variations in usage are also accounted for in determining baseline allowances.

The intent of the baseline and the tiered structure is to provide a portion of reasonable energy needs (baseline usage) of residential customers at the lowest rate, and to encourage conservation of energy by increasing the rate charges as energy usage increases. Statutory restrictions on tier one and two rates have shifted the burden of residential rate increases to the higher tier/usage customers. As part of the second phase of SCE's 2012 GRC, SCE requested certain rate design modifications that are intended to provide a more equitable, cost-based rate design.

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

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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 were allocated by the CPUC among the customers of the investor-owned utilities (SCE, PG&E and SDG&E). SCE billed and collected from its customers the costs of power purchased and sold by the CDWR. SCE will continue to bill and collect CDWR bond-related charges and direct access exit fees until 2022. The CDWR-related charges and a portion of direct access exit fees that are remitted directly to the CDWR are not recognized as electric utility operating revenue; but did affect customer rates. All CDWR power contracts that were allocated to SCE expired by the end of 2011. See "SCE: Results of Operations—Supplemental Operating Revenue Information" in the MD&A for further discussion of the impact of CDWR charges on customer rates.

Purchased Power and Fuel Supply

SCE obtains the power needed to serve its customers from its generating facilities and from sales by qualifying facilities, independent power producers, renewable power producers, the CAISO, and other utilities.

Natural Gas Supply

SCE requires natural gas to meet contractual obligations for power tolling agreements (power contracts in which SCE has agreed to provide or pay for the natural gas burned to generate electricity). SCE also requires natural gas to fuel its Mountainview and peaker plants, which are generation units that are designed to operate in response to changes in demand for power. The physical natural gas purchased by SCE is subject to competitive bidding.

Nuclear Fuel Supply

For San Onofre Units 2 and 3, contractual arrangements are in place covering 100% of the projected nuclear fuel requirements through the years indicated below:

Uranium concentrates	2020
Conversion	2020
Enrichment	2020
Fabrication	2015

For Palo Verde, contractual arrangements are in place covering 100% of the projected nuclear fuel requirements through the years indicated below:

Uranium concentrates	2017
Conversion	2018
Enrichment	2020
Fabrication	2016

Coal Supply

On January 1, 2010, SCE and the other Four Corners participants entered into a Four Corners Coal Supply Agreement with the BHP Navajo Coal Company, under which coal will be supplied to Four Corners Units 4 and 5 until July 6, 2016. The co-owners of Four Corners (excluding SCE) are currently negotiating a potential new Coal Supply Agreement with BHP Navajo Coal Company for the period after July 6, 2016. In November 2010, SCE entered into an agreement to sell its interest in Four Corners subject to certain conditions and regulatory approvals. See "Item 8. Edison International Notes to Consolidated Financial Statements—Note 2. Property, Plant and Equipment," for more information on the sale of SCE's interest in Four Corners.

CAISO Wholesale Energy Market

In California and other states, wholesale energy markets exist through which competing electricity generators offer their electricity output to electricity retailers. Each state's wholesale electricity market is generally operated by its state ISO or a regional RTO. California's wholesale electricity market is operated by the CAISO. The CAISO schedules power in hourly increments with hourly prices through a real-time and day-ahead market that combines energy, ancillary services, unit commitment and congestion management. SCE participates in the day-ahead and real-time markets for the sale of its generation and purchases of its load requirements.

The CAISO uses a nodal locational pricing model, which sets wholesale electricity prices at system points ("nodes") that

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reflect local generation and delivery costs. Generally, SCE schedules its electricity generation to serve its load but when it has excess generation or the market price of power is more economic than its own generation, SCE may sell power from utility-owned generation assets and existing power procurement contracts into, or buy generation and/or ancillary services to meet its load requirements from, the day-ahead market. SCE will offer to buy its generation at nodes near the source of the generation, but will take delivery at nodes throughout SCE's service territory. Congestion may occur when available energy cannot be delivered due to transmission constraints, which results in transmission congestion charges and differences in prices at various nodes. The CAISO also offers congestion revenue rights or CRRs, a commodity that entitles the holder to receive (or pay) the value of transmission congestion between specific nodes, acting as an economic hedge against transmission congestion charges.

Competition

Because SCE is an electric utility company operating within a defined service territory pursuant to authority from the CPUC, SCE faces retail competition only to the extent that federal and California laws permit other entities to provide electricity and related services to customers within SCE's service territory. While California law provides only limited opportunities for customers to choose to purchase power directly from an energy service provider other than SCE, a California statute was adopted in 2009 that permits a limited, phased-in expansion of customer choice (direct access) for nonresidential customers. SCE also faces some competition from cities and municipal districts that create municipal utilities or community choice aggregators. Competition between SCE and other electricity providers is conducted mainly on the basis of price; customers seek the lowest cost power available. The effect of this competition on SCE generally is to reduce the number of customers purchasing power from SCE, but those departing customers typically continue to utilize and pay for SCE's transmission and distribution services.

Technological developments, such as on-site power generation (self generation), pose additional competitive challenges for traditional utilities. See "Item 1A. Risk Factors—Risks Relating to SCE—Regulatory Risks." In the area of transmission infrastructure, SCE may experience increased competition from merchant transmission providers. The FERC has made changes to its transmission planning requirements with the goal of opening transmission development to competition from independent developers. In July 2011, the FERC adopted new rules that remove incumbent public utility transmission owners' federally-based right of first refusal to construct certain new transmission facilities. The rules direct regional entities, such as ISOs, to create new processes that would allow other providers to develop new transmission projects. The new processes will not become effective until approved by the FERC, which is expected in late 2012. The majority of SCE's 2012 – 2014 transmission capital forecast relates to transmission projects that have been approved by the CAISO and barring a re-evaluation under the new rules, will not be subject to the new processes. SCE does not expect these projects to be re-evaluated. The impact of the new rules on future transmission projects will depend on the processes ultimately implemented by regional entities.

Properties

SCE supplies electricity to its customers through extensive transmission and distribution networks. Its transmission facilities, which are located primarily in California but also in Nevada and Arizona, deliver power from generating sources to the distribution network and consist of lines ranging from 33 kV to 500 kV and substations. SCE's distribution system, which takes power from substations to customers, includes over 59,000 circuit miles of overhead lines, 44,000 circuit miles of underground lines and over 700 distribution substations, all of which are located in California.

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SCE owns the generating facilities listed in the following table.

Generating Facility	Location (in CA, unless otherwise noted)	Fuel Type	Operator	SCE's Ownership Interest (%)		Net Physical Capacity (in MW)	SCE's Capacity pro rata share (in MW)
San Onofre Nuclear Generating Station	South of San Clemente	Nuclear	SCE	78.21	%	2,150	1,760
Hydroelectric Plants (36)	Various	Hydroelectric	SCE	100	%	1,176	1,176
Pebbly Beach Generating Station	Catalina Island	Diesel	SCE	100	%	9	9
Mountainview	Redlands	Natural Gas	SCE	100	%	1,050	1,050
Peaker Plants (4)	Various	Gas fueled Combustion Turbine	SCE	100	%	196	196
Palo Verde Nuclear Generating Station	Phoenix, AZ	Nuclear	APS	15.8	%	3,739	591
Four Corners Units 4 and 5	Farmington, NM	Coal-fired	APS	48	%[1]	1,540	739
Solar PV Plants (23)	Various	Photovoltaic	SCE	100	%	53	53
Total						9,913	5,574

1 In November 2010, SCE entered into an agreement to sell its interest in Four Corners to APS for approximately $294 million. The sale is contingent upon the satisfaction of several conditions and the obtaining of multiple regulatory approvals. Currently SCE estimates that the sale will close in the second half of 2012. See "Item 8. Edison International Notes to Consolidated Financial Statements—Note 2. Property, Plant and Equipment" for more information.

San Onofre, Four Corners, certain of SCE's substations, and portions of its transmission, distribution and communication systems are located on lands owned by the United States or others under licenses, permits, easements or leases, or on public streets or highways pursuant to franchises. Certain of the documents evidencing such rights obligate SCE, under specified circumstances and at its expense, to relocate such transmission, distribution, and communication facilities located on lands owned or controlled by federal, state, or local governments.

Twenty-eight of SCE's 36 hydroelectric plants and related reservoirs are located in whole or in part on U.S.-owned lands pursuant to 30- to 50-year FERC licenses that expire at various times between 2012 and 2046. Such licenses impose numerous restrictions and obligations on SCE, including the right of the United States to acquire projects upon payment of specified compensation. When existing licenses expire, the FERC has the authority to issue new licenses to third parties that have filed competing license applications, but only if their license application is superior to SCE's and then only upon payment of specified compensation to SCE. New licenses issued to SCE are expected to contain more restrictions and obligations than the expired licenses because laws enacted since the existing licenses were issued require the FERC to give environmental objectives greater consideration in the licensing process.

Substantially all of SCE's properties are subject to the lien of a trust indenture securing first and refunding mortgage bonds. See "Item 8. Edison International Notes to Consolidated Financial Statements—Note 5. Debt and Credit Agreements."

Seasonality

Due to warm weather during the summer months and SCE's rate design, operating revenue during the third quarter of each year is generally higher than the other quarters.

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EDISON MISSION GROUP INC.

Overview

EMG's competitive power generation business primarily consists of the generation and sale into the PJM market of energy and capacity from merchant coal-fired power plants and a portfolio of natural gas and wind projects. EMG's operating results were significantly lower in 2011 compared to 2010 due to lower realized energy and capacity prices and generation at the coal plants.

At December 31, 2011, EME had corporate cash and cash equivalents of $951 million and $498 million of available borrowing capacity under its $564 million revolving credit facility maturing in June 2012 and Midwest Generation had cash and cash equivalents of $213 million and $497 million of available borrowing capacity under its $500 million credit facility maturing in June 2012. Subsequent to the end of the fiscal year, EME terminated its revolving credit facility and there can be no assurance that Midwest Generation will be eligible to draw on its credit facility prior to maturity. Any replacements of these credit lines will likely be on less favorable terms and conditions, and there is no assurance that EME will, or will be able to, replace these credit lines or any portion of them. EME had $3.7 billion of unsecured notes outstanding at December 31, 2011, $500 million of which mature in 2013. Unless energy and capacity prices increase, EME expects that it will experience further reductions in cash flow and losses in 2012 and subsequent years. EME's liquidity will be strained by a continuation of recent adverse trends, combined with pending debt maturities, higher operating costs and the need to retrofit its coal-fired plants to comply with governmental regulations. To address such a scenario, EME would need to consider all options available to it, including potential sales of assets or restructurings or reorganization of the capital structure of EME and its subsidiaries.

Homer City failed to obtain sufficient interest from market participants to fund the capital improvements during the process undertaken in the fourth quarter of 2011. Homer City is currently engaged in discussions with the owner-lessors regarding the potential for such funding. EME expects that the outcome of any such discussions, if successful in providing funding for the Homer City plant, will likely result in EME's loss of substantially all beneficial economic interest in and material control of the Homer City plant. Failure to resolve the source of funding of necessary capital expenditures for the Homer City plant could result in Homer City's default under the lease agreements giving rise to remedies for the owner-lessors and secured lease obligation bondholders, which could include foreclosing on the leased assets, the general partner of Homer City, or both. For further discussion of these matters, see "Edison International Overview—Management Overview of EMG" in the MD&A.

Regulation

Federal Power Act

The FERC has exclusive jurisdiction over the rates, terms and conditions of wholesale sales of electricity and transmission services in interstate commerce (other than transmission that is "bundled" with retail sales), including ongoing, as well as initial, rate jurisdiction. The FERC also has jurisdiction over the sale or transfer of specified assets, including wholesale power sales contracts and generation facilities and, in some cases, jurisdiction over the issuance of securities or the assumption of specified liabilities. Dispositions of EMG's jurisdictional assets and certain types of financing arrangements may require FERC approval.

Each of EMG's domestic generating facilities is either a qualifying facility, as determined by the FERC, or the subsidiary owning the facility is an exempt wholesale generator. Most qualifying facilities, including EMG's qualifying facilities, are exempt from the ratemaking and several other provisions of the Federal Power Act. EMG's exempt wholesale generators are subject to the FERC's ratemaking jurisdiction under the Federal Power Act, but have been authorized by the FERC to sell power at market-based rates. In addition, EMG's power marketing subsidiaries, including EMMT, have been authorized by the FERC to make wholesale market sales of power at market-based rates and are subject to FERC ratemaking regulation under the Federal Power Act.

If one of the projects in which EMG has an interest were to lose its qualifying facility or exempt wholesale generator status, the project would no longer be entitled to the related exemptions from regulation and could become subject to rate regulation by the FERC and state authorities. Loss of status could also trigger defaults under covenants contained in the project's power sales agreements and financing agreements.

Transmission of Wholesale Power

EMG's projects that sell power to wholesale purchasers other than the local utility to which the project may be interconnected require the transmission of electricity over power lines owned by others. The prices and other terms and conditions of transmission contracts are regulated by the FERC when the entity providing the transmission service is subject to FERC jurisdiction.

Markets for Generation

The United States electric industry, including companies engaged in providing generation, transmission, distribution and retail sales and service of electric power, has undergone significant deregulation over the last three decades, which has led to increased competition, especially in the generation sector. In areas where ISOs and RTOs have been formed, market participants have open access to transmission service typically at a system-wide rate. ISOs and RTOs may also operate real-time and day-ahead energy and ancillary service markets, which are governed by FERC-approved tariffs and market rules. The development of such organized markets into which independent power producers are able to sell has reduced their dependence on bilateral contracts with electric utilities. In addition, capacity markets in various regional wholesale power markets compensate supply resources for the capability to supply electricity when needed, and demand resources, for electricity they avoid using.

Wholesale Markets

EMG's largest power plants are its coal power plants located in Illinois, which are collectively referred to as the Midwest Generation plants, and the Homer City plant located in Pennsylvania. Collectively, both the Midwest Generation plants and the Homer City plant are referred to as the coal plants in this annual report. The coal plants sell power primarily into PJM, an RTO which includes all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. Sales may also be made from PJM into the Midwest Independent Transmission System Operator ("MISO") RTO, which includes all or parts of Illinois, Wisconsin, Indiana, Michigan, Ohio and other states in the region, and into the NYISO, which controls the transmission grid and energy and capacity markets for New York State.

PJM operates a wholesale spot energy market and determines the market-clearing price for each hour based on bids submitted by participating generators indicating the minimum prices at which a bidder is willing to dispatch energy at various incremental generation levels. PJM requires all load-serving entities and generators, such as Midwest Generation and Homer City, to maintain prescribed levels of capacity, including a reserve margin, to ensure system reliability. PJM's capacity markets have a single market-clearing price for each capacity zone. In May of each year, PJM conducts an annual capacity auction ("RPM") to commit generation, energy efficiency and demand side resources three years forward, and to provide a long-term pricing signal for the construction of capacity resources.

Fuel Supply

The Midwest Generation plants purchase coal from several suppliers located in the Southern PRB of Wyoming. The total volume of coal consumed annually is largely dependent on the amount of generation and has historically ranged between 17 million to 19 million tons. Coal consumption in the current low natural gas price environment may be lower than the historical range. Coal is transported under transportation agreements with Union Pacific Railroad and various short-line carriers. In late 2011, Midwest Generation signed new agreements, effective January 1, 2012, to provide fuel transportation on a long-term basis. For additional information, see "EMG: Results of Operations—Market Risk Exposures—Commodity Price Risk—Coal and Transportation Risk" in the MD&A. As of December 31, 2011, Midwest Generation leased approximately 3,400 railcars to transport the coal from the mines to the generating stations, under leases with remaining terms that range from less than one year to eight years, with options to extend the leases or purchase some railcars at the end of the lease terms.

Homer City's Units 1 and 2 have historically consumed approximately 2.8 million to 3.3 million tons of mid-range sulfur coal per year. Two types of coal are purchased, ready-to-burn and raw coal. Ready-to-burn coal is of the quality that can be burned directly in Units 1 and 2, whereas the raw coal purchased for consumption by Units 1 and 2 must be cleaned in the Homer City coal cleaning facility, which has the capacity to clean up to 5 million tons of coal per year. Unit 3 has historically consumed approximately 1.5 million to 2 million tons of coal per year and can consume either raw or ready-to-burn coal. Coal consumption in the current low natural gas price environment may be lower than the historical range. A wet scrubber FGD system for Unit 3 enables this unit to burn less expensive, higher sulfur coal, while still meeting environmental standards for emission control. In general, the coal purchased for all three units is acquired locally. For additional information, see "Edison International Overview—Management Overview of EMG" and "EMG: Results of Operations—Market Risk Exposures—Commodity Price Risk—Coal and Transportation Risk" in the MD&A.

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Competition

EMG is subject to competition from energy marketers, public utilities, government-owned power agencies, industrial companies, financial institutions, and other independent power producers. These companies may have competitive advantages as a result of scale, the location of their generation facilities, or other factors. Some of EMG's competitors have a lower cost of capital than EMG and, in the case of utilities, may be able to recover fixed costs through rate base mechanisms, allowing them to build, buy and upgrade generation without relying exclusively on market clearing prices to recover their investments.

State and local environmental regulations, particularly those that impose stringent state-specific emission limits in Illinois, could put EMG's coal plants at a disadvantage compared with competing power plants operating in nearby states and subject to less stringent state emission limits or to federal emission limits alone. The CPS puts the Midwest Generation plants at a disadvantage compared with competing plants not subject to similar regulations, and federal air quality regulations such as CSAPR and the MATS rule will put EMG's coal plants, particularly Homer City, at a disadvantage compared to plants utilizing other fuels. Potential future climate change regulations could also put EME's coal plants at a disadvantage compared to power plants utilizing other fuels as well as utilities that can also be able to recover climate change compliance costs through rate base mechanisms. The ability of EMG's coal plants to compete may be affected by future environmental regulations, by governmental and regulatory activities designed to support the construction and operation of power generation facilities fueled by renewable energy sources, and by developments such as shale gas technology that lower the price of other fuels.

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Properties

Power Plants in Operation

As of December 31, 2011, EMG's operations consisted of ownership or leasehold interests in the following operating projects

Power Plants	Location	Primary Electric Purchaser[2]	Fuel Type	EMG's Ownership Interest		Net Physical Capacity (in MW)	EMG's Capacity Pro Rata Share (in MW)
MERCHANT POWER PLANTS							
Midwest Generation plants[1]	Illinois	PJM	coal	100	%	5,172	5,172
Midwest Generation plants[1]	Illinois	PJM	oil	100	%	305	305
Homer City plant[1]	Pennsylvania	PJM	coal	100	%	1,884	1,884
Merchant Wind							
Goat Wind	Texas	ERCOT	wind	99.9	%[3]	150	150
Lookout	Pennsylvania	PJM	wind	100	%	38	38
Big Sky	Illinois	PJM	wind	100	%	240	240
CONTRACTED POWER PLANTS – Domestic							
Natural Gas							
Big 4 Projects							
Kern River[1]	California	SCE	natural gas	50	%	300	150
Midway-Sunset[1]	California	PG&E	natural gas	50	%	225	113
Sycamore[1]	California	SCE	natural gas	50	%	300	150
Watson	California	SCE	natural gas	49	%	385	189
Westside Projects (4)[1]	California	PG&E	natural gas	50	%	152	76
Sunrise[1]	California	CDWR	natural gas	50	%	572	286
Renewable Energy							
Buffalo Bear	Oklahoma	WFEC	wind	100	%	19	19
Cedro Hill	Texas	CSA	wind	100	%	150	150
Community Wind North	Minnesota	NSPC	wind	99	%	30	30
Crosswinds	Iowa	CBPC	wind	99	%[3]	21	21
Elkhorn Ridge	Nebraska	NPPD	wind	67	%	80	53
Forward	Pennsylvania	CECG	wind	100	%	29	29
Hardin	Iowa	IPLC	wind	99	%[3]	15	15
High Lonesome	New Mexico	APSC	wind	100	%	100	100
Jeffers	Minnesota	NSPC	wind	99.9	%[3]	50	50
Laredo Ridge	Nebraska	NPPD	wind	100	%	80	80
Minnesota Wind projects[4]	Minnesota	NSPC/IPLC	wind	75-99%	[3]	73	67
Mountain Wind I	Wyoming	PC	wind	100	%	61	61
Mountain Wind II	Wyoming	PC	wind	100	%	80	80
Odin	Minnesota	MRES	wind	99.9	%[3]	20	20

Pinnacle[5]	West Virginia	MDGS/USM	wind	100	%	55	55
San Juan Mesa	New Mexico	SPS	wind	75	%	120	90
Sleeping Bear	Oklahoma	PSCO	wind	100	%	95	95
Spanish Fork	Utah	PC	wind	100	%	19	19
Storm Lake[1]	Iowa	MEC	wind	100	%	108	108
Taloga	Oklahoma	OGEC	wind	100	%	130	130
Wildorado	Texas	SPS	wind	99.9	%[3]	161	161
Huntington Waste-to-Energy	New York	LIPA	biomass	38	%	25	9
Coal							
American Bituminous[1]	West Virginia	MPC	waste coal	50	%	80	40
CONTRACTED POWER PLANTS – International							
Doga	Republic of Turkey	TEDAS	natural gas	80	%	180	144
Total						11,504	10,379

1 Plant is operated under contract by an EME operations and maintenance subsidiary or the plant is operated or managed directly by an EME subsidiary.

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[2] Electric purchaser abbreviations are as follows:

APSC	Arizona Public Service Company	NPPD	Nebraska Public Power District
CBPC	Corn Belt Power Cooperative	NSPC	Northern States Power Company
CDWR	California Department of Water Resources	OGEC	Oklahoma Gas and Electric Company
CECG	Constellation Energy Commodities Group, Inc.	PC	PacifiCorp
CSA	City of San Antonio	PG&E	Pacific Gas & Electric Company
ERCOT	Electric Reliability Council of Texas	PJM	PJM Interconnection, LLC
IPLC	Interstate Power and Light Company	PSCO	Public Service Company of Oklahoma
LIPA	Long Island Power Authority	SCE	Southern California Edison Company
MDGS	Maryland Department of General Services	SPS	Southwestern Public Service
MEC	Mid-American Energy Company	TEDAS	Türkiye Elektrik Dagitim Anonim Sirketi
MPC	Monongahela Power Company	USM	University System of Maryland
MRES	Missouri River Energy Services	WFEC	Western Farmers Electric Cooperative

[3] Represents EME's current ownership interest. If the project achieves a specified rate of return, EME's interest will decrease.

[4] Composed of six individual wind projects.

[5] Two-thirds of project achieved commercial operation in December 2011. The remaining one-third of project achieved commercial operation in January 2012.

Significant Customers

For information on EMG's significant customers, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 6. Derivative Instruments and Hedging Activities."

Asset Management and Trading Activities

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

- Asset Management–EMMT engages in the sale of energy and capacity and the purchase and sale of fuels, including natural gas and fuel oil, through intercompany contracts with EMG's subsidiaries that own or lease EMG's facilities. EMG uses derivative instruments to reduce its exposure to market risks that arise from price fluctuations of electricity, capacity, fuel, emission allowances, and transmission rights. The objective of these activities is to sell the output of EMG's facilities on a forward basis or to hedge the risk of future changes in prices or price differences between different locations. Hedging activities include on-peak and off-peak periods and may include load service requirements contracts with local utilities. Transactions related to hedging activities are designated separately from EMMT's trading activities. Not all contracts entered into by EMMT for hedging purposes qualify as hedges for accounting purposes.
- Trading–EMMT seeks to generate trading profits from volatility in the price of electricity, capacity, fuels, and transmission congestion by buying and selling contracts in wholesale markets under limitations approved by EMG's risk management committee.

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Energy and Infrastructure Investments

EMG's energy and infrastructure investments include leveraged leases and affordable housing projects in the United States. As of December 31, 2011, Edison Capital was the lessor with an investment balance (including current lease receivable) of $117 million in the following leveraged leases:

Transaction	Asset	Location	Basic Lease Term Ends	Investment Balance (In millions)	
Vidalia: selling power to Entergy Louisiana, City of Vidalia	192 MW hydro power plant	Vidalia, Louisiana	2020	$69	
Beaver Valley: selling power to Ohio Edison Company, Centerior Energy Corporation	836 MW nuclear power plant	Shippingport, Pennsylvania	2017	$46	
American Airlines	3 Boeing 767 ER aircraft	Domestic and international routes	2016	$8	[1]

[1] American Airlines filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code in November 2011. As a result, Edison Capital recorded a pre-tax $26 million charge related it its net investments in aircraft leases.

Seasonality

Due to fluctuations in electric demand resulting from warm weather during the summer months and cold weather during the winter months, electric revenues from the coal plants normally 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, income from the coal plants is seasonal and has significant variability from quarter to quarter. Seasonal fluctuations may also be affected by changes in market prices. For further discussion regarding market prices, see "EMG: Market Risk Exposures—Commodity Price Risk—Energy Price Risk" in the MD&A.

EMG's third quarter equity in income from its unconsolidated energy projects is normally higher than equity in income related to other quarters of the year due to seasonal fluctuations and higher energy contract prices during the summer months.

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ENVIRONMENTAL REGULATION OF EDISON INTERNATIONAL AND SUBSIDIARIES

Legislative and regulatory activities by federal, state, and local authorities in the United States relating to energy and the environment impose numerous restrictions on the operation of existing facilities and affect the timing, cost, location, design, construction and operation of new facilities by Edison International's subsidiaries, as well as the cost of mitigating the environmental impacts of past operations. Many of these laws, regulations and other activities affect both SCE and EMG's facilities, although not always to the same extent. The environmental regulations and other developments discussed below have the largest impact on fossil-fuel fired power plants, and therefore the discussion in this section focuses on regulations applicable to the states of California, New Mexico, Illinois and Pennsylvania, where such facilities are located.

Edison International continues to monitor legislative and regulatory developments and to evaluate possible strategies for compliance with environmental regulations. Additional information about environmental matters affecting Edison International, including projected environmental capital expenditures, is included in the MD&A under the heading "SCE: Liquidity—Capital Investment Plan," "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies" and "—Note 10. Environmental Developments, and "Edison International (Consolidated): Liquidity and Capital Resources—Critical Accounting Estimates and Policies—Impairment of Long-Lived Assets" in the MD&A.

Air Quality

The CAA, which regulates air pollutants from mobile and stationary sources, has a significant impact on the operation of fossil fuel plants, especially coal-fired plants. The CAA requires the US EPA to establish concentration levels in the ambient air for six criteria pollutants to protect public health and welfare. These concentration levels are known as National Ambient Air Quality Standards, or NAAQS. The six criteria pollutants are carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter, and SO_2.

Federal environmental regulations of these criteria pollutants require states to adopt state implementation plans, known as SIPs, for certain pollutants, which detail how the state will attain the standards that are mandated by the relevant law or regulation. The SIPs must be equal to or more stringent than the federal requirements and must be submitted to the US EPA for approval. Each state identifies the areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (non-attainment areas), and must develop a SIP both to bring non-attainment areas into compliance with the NAAQS and to maintain good air quality in attainment areas. If the attainment status of areas changes, states may be required to develop new SIPs that address the changes. Many of EMG's facilities are located in areas that have not attained NAAQS for ozone (affected by NO_x emissions from power plants) and fine particulate matter (affected by SO2 and NOx emissions from power plants) and much of Southern California is in a non-attainment area for several criteria pollutants.

As described further below, on December 11, 2006, Midwest Generation entered into an agreement with the Illinois EPA, which was subsequently embodied in an Illinois rule called the Combined Pollutant Standard or "CPS," to reduce mercury, NO_x and SO_2 emissions at the Midwest Generation plants. The CPS requires Midwest Generation to achieve air emission reductions for NO_x and SO_2, and those reductions should contribute to or effect compliance with various existing US EPA ambient air quality standards. It is possible that if lower ozone, particulate matter, NO_x or SO_2 NAAQS are finalized by US EPA in the future, Illinois may implement regulations that are more stringent than those required by the CPS.

Nitrogen Oxide and Sulfur Dioxide

Clean Air Interstate and Cross-State Air Pollution Rules

The CAIR, issued by the US EPA on March 10, 2005, mandated significant reductions in NO_x and SO_2 emission allowance caps under the CAA in 28 eastern states and the District of Columbia. In 2008, the U.S. Court of Appeals for the D.C. Circuit initially vacated the CAIR, but later remanded the CAIR to the US EPA for the issuance of a revised rule. The CAIR remains in effect until a replacement regulation becomes effective.

On July 6, 2011, the US EPA adopted the Cross-State Air Pollution Rule ("CSAPR"). CSAPR establishes emissions reductions for annual SO_2 emissions and annual and ozone season NO_x emissions in two phases: a first phase originally scheduled to be effective January 1, 2012 and, in most states subject to the program (including Illinois and Pennsylvania), a second phase effective January 1, 2014 that requires additional reductions in annual SO_2 emissions.

In December 2011, the United States Court of Appeals for the District of Columbia granted a stay of CSAPR pending completion of its review of the rule's validity. Oral argument is scheduled for April 13, 2012, and a court decision is expected during the third quarter of 2012. The court directed the US EPA to continue administering the CAIR until its review is completed.

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CSAPR, like the CAIR, is an allowance-based regulation that provides for emissions trading. If the stay is lifted and CSAPR becomes effective, the amount of actual SO_2 or NO_x emissions from plant operations will need to be matched by a sufficient amount of SO_2 or NO_x allowances that are either allocated or purchased in the open market. In connection with CSAPR, the US EPA has, for each phase, established SO_2 and NO_x allowance allocations for each state and each generating unit subject to the regulation, and at the close of the annual or seasonal compliance period, units will need to surrender allowances for each ton of SO_2 and NO_x emitted or face penalties.

With the staying of CSAPR, CAIR SO_2 allowances have been provided and a sufficient supply is available for purchase to permit Homer City to continue operations consistent with 2011 levels. If the stay is lifted, the SO_2 allowances allocated to Homer City in CSAPR Phase I (25,797 tons in 2012 and 2013) would be significantly lower than the amount that would be required based on Homer City's historical emissions. It is unclear at this time whether Homer City would be able to acquire allowances in sufficient quantity to cover its normal operations during Phase I of CSAPR and whether it would be able to pass through the cost of such allowances in the marketplace. Accordingly, despite the stay, Homer City continues to evaluate alternative options, including reduced dispatch and fuel modifications, for complying with Phase I of CSAPR. The cost of allowances, together with possible operational impacts or reductions of output that may be required to comply with Phase I of CSAPR, could have a material effect on Homer City.

Homer City has begun work on designing SO_2 and particulate emissions control equipment for Units 1 and 2. Based on preliminary estimates, Homer City expects the cost of such equipment to be approximately $700 million to $750 million. However, construction of these improvements is dependent upon funding from the owner-lessors or other third parties. For additional information, see "Edison International Overview—Management Overview of EMG—Homer City Lease."

Revised NAAQS for Sulfur Dioxide

In June 2010, the US EPA finalized the primary NAAQS for SO_2 by establishing a new one-hour standard at a level of 75 parts per billion. In June 2011, Pennsylvania and Illinois submitted their initial recommended attainment/nonattainment designations in connection with the standard. Pennsylvania recommended designating Indiana County, where the Homer City plant is located, as nonattainment for the SO_2 NAAQS. Illinois recommended designating parts of Tazewell County (where the Powerton plant is located) and Will and Cook Counties as nonattainment with this standard. The recommended designation for parts of Will and Cook Counties included the area where the Will County plant is located, but not the areas where Midwest Generation's other plants in those counties are located.

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 Midwest Generation plants. The agreement has been embodied in the CPS. All of Midwest Generation's Illinois coal-fired electric generating units are subject to the CPS. The CPS also specifies the control technologies that are to be installed on some units by specified dates. Midwest Generation must either install the required technology by the specified deadline or shut down the unit. 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. Midwest Generation substantially completed installation of SNCR equipment in 2011 for compliance with the emission limitations. Capital expenditures relating to these controls were $105 million.

SO_2 Emissions–Midwest Generation must comply with an overall SO_2 annual emission rate beginning with 0.44 lbs/million Btu in 2013 and decreasing annually until it reaches 0.11 lbs/million Btu in 2019 and thereafter.

Testing of dry scrubbing using Trona on select Midwest Generation units has demonstrated significant reductions in SO_2 emissions. Use of dry sorbent injection technology in conjunction with low sulfur coal is expected to require substantially less capital and time to construct than the use of spray dryer absorber technology, but would likely result in higher ongoing operating costs and may consequently result in lower dispatch rates and competitiveness of Midwest Generation's plants, depending on competitors' costs. For further discussion, see "Edison International Overview—Management Overview of EMG—Midwest Generation and Compliance Plans and Cost" in the MD&A.

Pennsylvania

The Homer City plant was subject to the federal CAIR during 2011 and complied with both the NO_x and SO_2 requirements by using existing equipment and purchasing SO_2 allowances. Pennsylvania adopted a state version of the CAIR, which the US EPA approved in December 2009. Homer City expects to comply with the Pennsylvania CAIR, which is substantially

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similar to the federal CAIR as it existed prior to the implementation of CSAPR, in the same manner in which it complies with the federal standards.

Mercury/Hazardous Air Pollutants

Mercury and Air Toxics Standards Rule

In December 2011, the US EPA announced the Mercury and Toxics Air Standards ("MATS") rule, limiting emissions of hazardous air pollutants from coal- and oil-fired electrical generating units. The rule was published in the Federal Register on February 16, 2012, and becomes effective on April 16, 2012. EMG does not expect that these standards will require Midwest Generation to make material changes to the approach to compliance with state and federal environmental regulations that it contemplates for CPS compliance. EMG also does not expect that these standards will require Homer City to make additional capital expenditures beyond those that would be required for compliance with CSAPR Phase II.

Illinois

The CPS requires that, beginning in calendar year 2015, and continuing thereafter on a rolling 12-month basis, Midwest Generation must either achieve an emission standard of .008 lbs mercury/GWh gross electrical output or a minimum 90% reduction in mercury for each unit (except Unit 3 at the Will County Station, which will be included in calendar year 2016). Midwest Generation will be required to install cold side electrostatic precipitator or baghouse equipment on Unit 7 at the Waukegan Station by December 31, 2013, and on Unit 3 at the Will County Station by December 31, 2015.

Pennsylvania

Pennsylvania currently has no state level mercury regulations.

Ozone

National Ambient Air Quality Standards

In January 2010, the US EPA proposed a revision to the primary and secondary NAAQS for 8-hour ozone that it had finalized in 2008. The 8-hour ozone standard established in 2008 was 0.075 parts per million. In January 2010, the US EPA proposed establishing a primary 8-hour ozone NAAQS between 0.060 and 0.070 parts per million and a distinct secondary standard to protect sensitive vegetation and ecosystems. In September 2011, President Obama announced that the proposed revision was being withdrawn. The ozone NAAQS established in 2008 remains in place, but the implementation process must be completed before the 0.075 parts-per-million standard can be enforced. The US EPA has indicated that it intends to issue initial area designations of attainment, nonattainment, and unclassifiable areas across the nation in 2012. States will then be required to develop and submit SIPs outlining how compliance with the 2008 NAAQS will be achieved. New primary and secondary ozone standards are expected in 2014.

In January 2012, the US EPA indicated that it intended to designate the counties in Illinois where Midwest Generation's coal-fired power plants are located as nonattainment with the 2008 NAAQS. In December 2011, the US EPA indicated that it intended to designate Indiana County, where the Homer City plant is located, as in attainment with the 2008 NAAQS.

Regional Haze

The regional haze rules under the CAA are designed to prevent impairment of visibility in certain federally designated areas. The goal of the rules 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 ("BART") or implement other control strategies to meet regional haze control requirements.

In relation to Four Corners, the US EPA issued its proposed FIP in October 2010. The proposed FIP would require the installation of SCR pollution control equipment within designated time periods. In November 2010, SCE and APS entered into an agreement for the sale of SCE's interest in Four Corners Units 4 and 5 to APS, subject to regulatory approvals and other conditions. Due to the investment constraints of SB 1368, the California law on GHG emission performance standards discussed below in "—Greenhouse Gas Regulation—Regional Initiatives and State Legislation," SCE does not expect to be a Four Corners participant after the 2016 expiration of the current participant agreements and does not expect to participate in any investment in Four Corners SCRs. See "Item 8. Edison International Notes to Consolidated Financial Statements—Note 2. Property, Plant and Equipment" for more information on the sale of SCE's interest in Four Corners.

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Illinois and Pennsylvania

Both Pennsylvania and Illinois have submitted their proposed SIP revisions to the US EPA to address regional haze. Illinois proposed that the emission reductions that the Midwest Generation plants will be required to make pursuant to the CPS, discussed above in "—Nitrogen Oxide and Sulfur Dioxide—Illinois," satisfy the BART requirement. Pennsylvania proposed that the existing particulate matter emission limits on the Homer City plant, as well as the plant's participation in the CAIR, would satisfy the BART requirement in that state. Because the CAIR was scheduled to expire on December 31, 2011, the US EPA proposed, on December 30, 2011, a limited disapproval of Pennsylvania's SIP, as well as a Federal Implementation Plan that would allow the Homer City plant's participation in CSAPR to satisfy the BART requirement. It is unclear how the stay of CSAPR will affect the Pennsylvania SIP. EME believes that the control measures being undertaken to comply with other environmental regulations will likely satisfy the requirements of these SIPs.

New Source Review Requirements

The NSR regulations impose certain requirements on facilities, such as electric generating stations, if modifications are made to air emissions sources at the facility. Since 1999, the US EPA has pursued a coordinated compliance and enforcement strategy to address NSR compliance issues at the nation's coal-fired power plants. The US EPA has filed enforcement actions against Homer City and Midwest Generation alleging NSR violations. For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies."

New Mexico

In April 2009, APS, as operating agent of Four Corners, received a US EPA request pursuant to Section 114 of the CAA for information about Four Corners, including information about Four Corners' capital projects from 1990 to the present. SCE understands that in other cases the US EPA has utilized responses to similar Section 114 letters to examine whether power plants have triggered NSR requirements under the CAA. In October 2011, four environmental organizations filed a lawsuit against the Four Corners owners alleging NSR violations. See "Item 8. Edison International Notes to Consolidated Financial Statements—Note 2. Property, Plant and Equipment," for information on the sale of SCE's interest in Four Corners.

Water Quality

Clean Water Act

Regulations under the federal Clean Water Act govern critical operating parameters at generating facilities, such as the temperature of effluent discharges and the location, design and construction of cooling water intake structures at generating facilities. In March 2011, the US EPA proposed standards under the federal Clean Water Act that would affect cooling water intake structures at generating facilities. The standards are intended to protect aquatic organisms by reducing capture in screens attached to cooling water intake structures (impingement) and in the water volume brought into the facilities (entrainment). The regulations are expected to be finalized by July 2012. The required measures to comply with the proposed standards regarding entrainment are subject to the discretion of the permitting authority, and Edison International is unable at this time to assess potential costs of compliance, which could be significant for the Midwest Generation plants and San Onofre, but are not expected to be material for the Homer City plant, which already has cooling towers.

California—Prohibition on the Use of Ocean-Based Once-Through Cooling

California has a US EPA-approved program to issue individual or group permits for the regulation of Clean Water Act discharges. California also regulates certain discharges not regulated by the US EPA. Effective October 1, 2010, the California State Water Resources Control Board issued a final policy, which establishes closed-cycle wet cooling as required technology for retrofitting existing once-through cooled plants like SCE's San Onofre and many of the existing fossil-fueled power plants along the California coast. The final policy required an independent engineering study to be completed prior to the fourth quarter of 2013 regarding the feasibility of compliance by California's two coastal nuclear power plants. The policy may result in significant capital expenditures at San Onofre and may affect its operations.

Illinois

Midwest Generation is a party to an administrative proceeding before the Illinois Pollution Control Board to determine whether more stringent thermal and effluent water quality standards for the Chicago Area Waterway

System and Lower Des Plaines River, which supply cooling water to Midwest Generation's Will County and Joliet Stations, will be implemented. The rule, if implemented, is expected to affect the manner in which those stations use water for station cooling. 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.

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Coal Combustion Wastes
US EPA regulations currently classify coal ash and other coal combustion residuals as solid wastes that are exempt from hazardous waste requirements. This classification enables beneficial uses of coal combustion residuals, such as for cement production and fill materials. Midwest Generation currently provides a portion of its coal combustion residuals for beneficial uses. In June 2010, the US EPA published proposed regulations relating to coal combustion residuals that could result in their reclassification. For further discussion see "Item 8. Edison International Notes to Consolidated Financial Statements— Note 10. Environmental Developments."

Greenhouse Gas Regulation
There have been a number of federal and state legislative and regulatory initiatives to reduce GHG emissions. Any climate change regulation or other legal obligation that would require substantial reductions in GHG emissions or that would impose additional costs or charges for the emission of GHGs could significantly increase the cost of generating electricity from fossil fuels, and especially from coal-fired plants, as well as the cost of purchased power, which could adversely affect Edison International.

Federal Legislative/Regulatory Developments
In June 2010, the US EPA issued the Prevention of Significant Deterioration ("PSD") and Title V Greenhouse Gas Tailoring Rule, known as the "GHG tailoring rule." This regulation generally subjects newly constructed sources of GHG emissions and newly modified existing major sources to the PSD air permitting program beginning in January 2011 (and later, to the Title V permitting program under the CAA); however the GHG tailoring rule significantly increases the emissions thresholds that apply before facilities are subjected to these programs. The emissions thresholds for CO2 equivalents in the final rule vary from 75,000 tons per year to 100,000 tons per year depending on the date and whether the sources are new or modified.

Regulation of GHG emissions pursuant to the PSD program could affect efforts to modify EMG's or SCE's facilities in the future, and could subject new capital projects to additional permitting or emissions control requirements that could delay such projects. In December 2010, the US EPA announced that it had entered into a settlement with various states and environmental groups to resolve a long-standing dispute over regulation of GHGs from electrical generating units pursuant to the New Source Performance Standards in the CAA and would propose performance standards for emissions from new and modified power plants and emissions guidelines for existing power plants. The specific requirements will not be known until the regulations are finalized. Since January 2010, the US EPA's Final Mandatory GHG Reporting Rule has required all sources within specified categories, including electric generation facilities, to monitor emissions and to submit annual reports to the US EPA by March 31 of each year. EMG's 2011 GHG emissions were approximately 43 million metric tons. SCE's 2011 GHG emissions were approximately 5.8 million metric tons.

Regional Initiatives and State Legislation
Regional initiatives and state legislation may also require reductions of GHG emissions and it is not yet clear whether or to what extent any federal legislation would preempt them. If state and/or regional initiatives remain in effect after federal legislation is enacted, utilities and generators could be required to satisfy them in addition to the federal standards.

Edison International subsidiary operations in California are subject to two laws governing GHG emissions. The first law, the California Global Warming Solutions Act of 2006 (also referred to as AB 32), establishes a comprehensive program to reduce GHG emissions. AB 32 requires the California Air Resources Board ("CARB") to develop regulations, effective in 2012, that would reduce California's GHG emissions to 1990 levels in yearly increments by 2020. In December 2011, the CARB regulation was officially published establishing a California cap-and-trade program. The first compliance period under the regulations is for 2013 GHG emissions. CARB regulations implementing a cap-and-trade program and the cap-and-trade program itself, continue to be the subject of litigation. In December 2011, a federal district court enjoined the Low Carbon Fuel Standard, another AB 32 program regulating the carbon content of transportation fuels, on constitutional commerce clause grounds. Additional litigation challenging the cap-and-trade program on similar grounds is expected, though no suit has been filed to date.

The second law, SB 1368, required the CPUC and the CEC to adopt GHG emission performance standards restricting the ability of California investor-owned and publicly owned utilities, respectively, to enter into long-term arrangements for the purchase of electricity. The standards that have been adopted prohibit these entities, including SCE, from entering into long-term financial commitments with generators that emit more than 1,100 pounds of CO_2 per MWh, the performance of a combined-cycle gas turbine generator. SB 1368 may prohibit SCE from making emission control expenditures at Four Corners. See "Item 8. Edison International Notes to Consolidated Financial Statements—Note 2. Property, Plant and Equipment" for information on the sale of SCE's interest in Four Corners.

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California law has also required SCE to increase its electricity generated from renewable resources by at least 1% of its annual retail electricity sales per year so that 20% of its annual electricity sales are provided from such resources (the "RPS Program") by no later than December 31, 2010 or such later date as flexible compliance requirements permit. In accordance with the procurement rules and regulations, SCE demonstrated full compliance with the RPS Program in its March 2011 and August 2011 filings.

In April 2011, California enacted a law requiring California retail sellers of electricity to procure 33% of their customers' electricity requirements from renewable resources, as defined in the statute. The impact of the new 33% law will depend on how the CPUC and CEC implement the law, which remains uncertain. On December 1, 2011, the CPUC approved a decision setting procurement quantity requirements for CPUC-regulated retail sellers that incrementally increase to 33% over several periods between January 2011 and December 31, 2020. The quantity would remain at 33% of retail sales for each year thereafter. Currently SCE estimates its delivery of eligible renewable resources to customers to be 21% of its total energy portfolio for 2011.

Litigation Developments

Litigation alleging that GHG is a public and private nuisance may affect Edison International and its subsidiaries, whether or not they are named as defendants. The law is unsettled on whether this litigation presents questions capable of judicial resolution or political questions that should be resolved by the legislative or executive branches. For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 10. Environmental Developments."

ITEM 1A. RISK FACTORS

RISKS RELATING TO EDISON INTERNATIONAL

Edison International's subsidiaries are subject to extensive regulation and the risk of adverse regulatory decisions and changes in applicable regulations or legislation.

SCE operates in a highly regulated environment. SCE's business is subject to extensive federal, state and local energy, environmental and other laws and regulations. The CPUC regulates SCE's retail operations, and the FERC regulates SCE's wholesale operations. The NRC regulates SCE's nuclear power plants. The construction, planning, and project site identification of SCE's power plants and transmission lines in California are also subject to the jurisdiction of the California Energy Commission (for plants 50 MW or greater), and the CPUC. SCE must periodically apply for licenses and permits from these various regulatory authorities and abide by their respective orders. Should SCE be unsuccessful in obtaining necessary licenses or permits or should these regulatory authorities initiate any investigations or enforcement actions or impose penalties or disallowances on SCE, SCE's business could be adversely affected. The process of obtaining licenses and permits from regulatory authorities may be delayed or defeated by concerted community opposition and such delay or defeat would have an adverse effect on SCE's business.

EMG's projects are subject to federal laws and regulations that govern, among other things, transactions by and with purchasers of power, including utility companies, the development and construction of generation facilities, the ownership and operations of generation facilities, and access to transmission. Generation facilities are also subject to federal, state and local laws and regulations that govern, among other things, the geographical location, zoning, land use and operation of a project. EMG in the course of its business must obtain and periodically renew licenses, permits and approvals for its facilities. The FERC may impose various forms of market mitigation measures, including price caps and operating restrictions, where it determines that potential market power might exist and that the public interest requires mitigation. Independent System Operators and Regional Transmission Operators may impose bidding and scheduling rules, both to curb the potential exercise of market power and to facilitate market functions. EMG is required to surrender emission allowances equal to emissions of specific substances in connection with the operation of its facilities. This may require the purchase of allowances, which are subject to price volatility and which could be unavailable.

This extensive governmental regulation creates significant risks and uncertainties for Edison International's business. Existing regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to SCE, EMG or their facilities or operations in a manner that may have a detrimental effect on Edison International's business or result in significant additional costs. In addition, regulation adopted via the public initiative process may apply to SCE or EMG, or its facilities or operations in a manner that may have a detrimental effect on Edison International's business or result in significant additional costs.

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Edison International's subsidiaries are subject to extensive environmental regulations that may involve significant and increasing costs and adversely affect them.

Edison International's subsidiaries are subject to extensive and frequently changing environmental regulations and permitting requirements that involve significant and increasing costs and substantial uncertainty. SCE and EMG devote significant resources to environmental monitoring, emissions control equipment, mitigation projects, and emission allowances to comply with existing and anticipated environmental regulatory requirements. However, the current trend is toward more stringent standards, stricter regulation, and more expansive application of environmental regulations. The adoption of laws and regulations to implement greenhouse gas controls could adversely affect operations, particularly of the coal-fired plants. Other environmental laws, particularly with respect to air emissions, disposal of ash, wastewater discharge, and cooling water systems, are also generally becoming more stringent. The continued operation of SCE and EMG facilities, particularly the coal-fired facilities, is expected to require substantial capital expenditures for environmental controls or cessation of operations. Cessation of operations of such coal-fired plants at EMG would have a material adverse effect on EMG. SCE and EMG may also be exposed to risks arising from past, current or future contamination at its former or existing facilities or with respect to offsite waste disposal sites that have been used in its operations. Current and future state laws and regulations in California also could increase the required amount of power that must be procured from renewable resources. For further discussion of the environmental regulations applicable to Edison International and its subsidiaries, see "Item 1. Business—Environmental Regulation of Edison International and Subsidiaries" and "Item 8. SCE Notes to Consolidated Financial Statements—Note 10. Environmental Developments."

Edison International's liquidity depends on SCE's ability to pay dividends to Edison International and its subsidiaries' payment of tax-allocation payments that may become due to Edison International.

Edison International is a holding company and, as such, it has no operations of its own. Edison International's ability to meet its financial obligations and to pay dividends on its common stock at the current rate is primarily dependent on the earnings and cash flows of SCE and its ability to make upstream distributions. Prior to paying dividends to Edison International, SCE has financial and regulatory obligations that must be satisfied, including, among others, debt service and preferred stock dividends. SCE and EMG may also owe tax-allocation payments to Edison International under applicable tax-allocation or payment agreements. Financial market and economic conditions may have an adverse effect on Edison International's subsidiaries. See "Risks Relating to SCE" and "Risks Relating to EMG" below for further discussion.

The businesses of Edison International's subsidiaries may be adversely affected by technological developments.

Technological advancements such as energy storage or self generation via solar panels may adversely affect the economics of SCE's business as a regulated utility. Other technological advancements in the area of power production that create or increase the supply of less expensive power, such as shale natural gas extraction technology, may adversely affect EMG's business as an independent merchant power producer. See "Risks Relating to SCE" and "Risks Relating to EMG" below for further discussion.

The generation, transmission and distribution of electricity are dangerous and involve inherent risks of injury to employees and the general public.

Electricity is dangerous for employees and the general public should they come in contact with power lines or electrical equipment. Injuries caused by such contact can subject SCE and EMG to liability that, despite the existence of insurance coverage, can be significant. In the wake of recent natural disasters such as windstorms, which can cause wildfires, pole failures and associated property damage and outages, the CPUC has increased its focus on public safety issues with an emphasis on heightened compliance with construction and operating standards and the potential for penalties being imposed on utilities. Such penalties and liabilities could be significant but are very difficult to predict. The range of possible penalties and liabilities includes amounts that could adversely affect SCE's and EMG's liquidity and results of operations.

RISKS RELATING TO SCE

Regulatory Risks

SCE's financial results depend upon its ability to recover its costs in a timely manner from its customers through regulated rates.

SCE's ongoing financial results depend on its ability to recover from its customers in a timely manner its costs, including the costs of electricity purchased for its customers, through the rates it charges its customers as approved by the CPUC and FERC. SCE's financial results also depend on its ability to earn a reasonable return on capital, including long-term debt and equity. SCE's capital investment plan, increasing procurement of renewable power, increasing environmental regulations, moderating demand, and the cumulative impact of other public policy requirements, collectively place continuing upward pressure on customer rates. Increases in self generation also reduce the pool of customers from whom fixed costs are recovered, while costs potentially increase due to system modifications that may be necessary to cope with the systemic effects of self-generation. Customers that self-generate their own power do not currently pay most transmission and distribution charges and are only subject to certain non-bypassable charges. The net result is to increase utility rates further for those customers who do not self-generate, which encourages more self generation and further rate increases. If SCE is unable to obtain a sufficient rate increase or to recover material amounts of its costs in rates in a timely manner or recover an adequate return on capital, its financial condition and results of operations could be materially adversely affected. For further information on SCE's rate requests, see "Edison International Overview—Management Overview of SCE—2012 General Rate Case" and "—FERC Formula Rates" in the MD&A.

SCE's energy procurement activities are subject to regulatory and market risks that could adversely affect its financial condition and liquidity.

SCE obtains energy, capacity, environmental credits and ancillary services needed to serve its customers from its own generating plants, as well as through contracts with energy producers and sellers. California law and CPUC decisions allow SCE to recover through the rates it is allowed to charge its customers reasonable procurement costs incurred in compliance with an approved procurement plan. Nonetheless, SCE's cash flows remain subject to volatility primarily resulting from changes to commodity prices. In addition, SCE is subject to the risks of unfavorable or untimely CPUC decisions about the compliance with SCE's procurement plan and the reasonableness of certain procurement-related costs.

SCE may not be able to hedge its risk for commodities on economic terms or fully recover the costs of hedges through the rates it is allowed to charge its customers, which could adversely affect SCE's liquidity and results of operations. See "SCE: Liquidity and Capital Resources—Market Risk Exposures" in the MD&A.

Operating Risks

SCE's financial condition and results of operations could be materially adversely affected if it is unable to successfully manage the risks inherent in operating and improving its facilities.

SCE's infrastructure is aging and could pose a risk to system reliability. In order to mitigate this risk, SCE is engaged in one of the largest infrastructure investment programs in its history, which involves multiple large-scale projects in multiple locations. This substantial increase in activity from SCE's historical levels elevates the operational risks and the need for superior execution in its activities. SCE's financial condition and results of operations could be materially affected if it is unable to successfully manage these risks as well as the risks inherent in operating and improving its facilities, the operation of which can be hazardous. SCE's inherent operating risks include such matters as the risks of human performance, workforce capabilities, public opposition to infrastructure projects, delays, environmental mitigation costs, difficulty in estimating costs, system limitations and degradation, and interruptions in necessary supplies. For example, SCE has recently experienced significant additional costs and disruptions in the progress of its Tehachapi Renewable Transmission Project. See "SCE: Liquidity and Capital Resources—Capital Investment Plan" in the MD&A.

SCE's systems and network infrastructure may be vulnerable to cyber attacks, intrusions or other catastrophic events that could result in their failure or reduced functionality.

Regulators, such as the NERC, and U.S. Government Departments, including the Departments of Defense, Homeland Security and Energy, have noted that the U.S. national electric grid and other energy infrastructures have potential vulnerabilities to cyber attacks and disruptions and that such cyber threats are becoming increasingly sophisticated and dynamic. SCE's operations require the continuous operation of critical information technology systems and network infrastructure. Although SCE actively monitors developments in this area and is involved in various industry groups and government initiatives, no security measures can completely shield such systems and infrastructure from vulnerabilities to cyber attacks, intrusions or other catastrophic events that could result in their failure or reduced functionality. If SCE's information technology systems security measures were to be breached or a critical system failure were to occur without timely recovery, SCE could be unable to fulfill critical business functions and/or sensitive confidential personal and other data could be compromised, which could adversely affect SCE's financial condition and results of operations. See "Item 1. Business—Southern California Edison Company—Regulation—NERC" for further discussion.

There are inherent risks associated with operating nuclear power generating facilities.

Continued NRC scrutiny of San Onofre may result in additional corrective actions that will increase operations and maintenance costs or require additional capital expenditures.

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San Onofre is subject to extensive oversight and scrutiny of the NRC. This scrutiny may result in SCE being required to take additional corrective actions and incur increased operations and maintenance expenses or new capital expenditures. If SCE is unable to take effective corrective actions required by the NRC, the NRC has the authority to impose fines or shut down a unit, or both, depending upon the NRC's assessment of the severity of the situation, until compliance is achieved. See "Item 1. Business—Southern California Edison Company—Regulation—Nuclear Power Plant Regulation" for further discussion.

Existing insurance and ratemaking arrangements may not protect SCE fully against losses from a nuclear incident.

Federal law limits public liability claims from a nuclear incident to the amount of available financial protection which is currently approximately $12.6 billion. SCE and other owners of the San Onofre and Palo Verde Nuclear Generating Stations have purchased the maximum private primary insurance available of $375 million per site. If nuclear incident liability claims were to exceed $375 million, the remaining amount would be made up from contributions of approximately $12.2 billion made by all of the nuclear facility owners in the U.S., up to an aggregate total of $12.6 billion. There is no assurance that the CPUC would allow SCE to recover the required contribution made in the case of one or more nuclear incident claims that exceeded $375 million. If this public liability limit of $12.6 billion is insufficient, federal law contemplates that additional funds may be appropriated by Congress. There can be no assurance of SCE's ability to recover uninsured costs in the event the additional federal appropriations are insufficient. See "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies—Nuclear Insurance."

Spent fuel storage capacity could be insufficient to permit long-term operation of SCE's nuclear plants.

The U.S. Department of Energy has defaulted on its obligation to begin accepting spent nuclear fuel from commercial nuclear industry participants by January 31, 1998. If SCE or the operator of Palo Verde were unable to arrange and maintain sufficient capacity for interim spent-fuel storage now or in the future, it could hinder the operation of the plants and impair the value of SCE's ownership interests until storage could be obtained, each of which may have a material adverse effect on SCE.

SCE's insurance coverage for wildfires arising from its ordinary operations may not be sufficient and Edison International may not be able to obtain sufficient insurance on SCE's behalf for such occurrences.

Edison International has been experiencing increased costs and difficulties in obtaining insurance coverage for wildfires that could arise from SCE's ordinary operations. In addition, the insurance Edison International has obtained on SCE's behalf for wildfire liabilities may not be sufficient. Uninsured losses and increases in the cost of insurance may not be recoverable in customer rates. A loss which is not fully insured or cannot be recovered in customer rates could materially and adversely affect Edison International's and SCE's financial condition and results of operations. Furthermore, insurance for wildfire liabilities may not continue to be available at all or at rates or on terms similar to those presently available to Edison International. See "Item 8. Edison International Notes to Consolidated Financial Statements—Note 10. Environmental Developments."

Financing Risks

As a capital intensive company, SCE relies on access to the capital markets. If SCE were unable to access the capital markets or the cost of financing were to substantially increase, its liquidity and operations would be adversely affected.

SCE regularly accesses the capital markets to finance its activities and is expected to do so by its regulators as part of its obligation to serve as a regulated utility. SCE's needs for capital for its ongoing infrastructure investment program are substantial. SCE's ability to arrange financing as well as its ability to refinance debt and make scheduled payments of principal and interest are dependent on numerous factors, including SCE's levels of indebtedness, maintenance of acceptable credit ratings, its financial performance, liquidity and cash flow, and other market conditions. SCE's failure to obtain additional capital from time to time would have a material adverse effect on SCE's liquidity and operations. See "SCE: Liquidity and Capital Resources—Capital Investment Plan" and "—Historical Segment Cash Flows" in the MD&A.

RISKS RELATING TO EMG

Liquidity Risks

EME and its subsidiaries have significant cash requirements, limited sources of capital and expect to incur substantial losses in 2012 and subsequent years.

At December 31, 2011, EME had corporate cash and cash equivalents of $951 million and $498 million of available

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borrowing capacity under its $564 million revolving credit facility maturing in June 2012 and Midwest Generation had cash and cash equivalents of $213 million and $497 million of available borrowing capacity under its $500 million credit facility maturing in June 2012. Subsequent to the end of the fiscal year, EME terminated its revolving credit facility and there can be no assurance that Midwest Generation will be eligible to draw on its credit facility prior to maturity. Any replacements of these credit lines will likely be on less favorable terms and conditions, and there is no assurance that EME will, or will be able to, replace these credit lines or any portion of them.

As of December 31, 2011, EME's consolidated debt was approximately $4.9 billion, of which $1.2 billion was nonrecourse project debt of EME's subsidiaries and the balance was senior unsecured debt of EME. In addition, EME's subsidiaries had $2.6 billion of long-term, power plant lease obligations that are due over a period ranging up to 23 years. Compliance with current and forthcoming environmental requirements will add to EME's near-term liquidity needs.

Unless energy and capacity prices increase, EME expects that it will experience further losses and reductions in cash flow in 2012 and subsequent years. EME's liquidity will be strained by a continuation of recent adverse trends combined with pending debt maturities, higher operating costs and the need to retrofit its coal-fired plants to comply with governmental regulations. EME's and Midwest Generation's deteriorating financial results and below-investment grade credit status may limit their ability to extend or replace credit facilities, including those maturing in 2012, should they choose to do so, and the terms and conditions of any refinancing could be substantially less favorable than those in previous credit facilities, depending on market conditions. In the case of a further downgrade, EME expects that these negative effects would become more pronounced. If cash flow and other means for assuring liquidity are unavailable or insufficient, EME may be unable to complete environmental improvements at its coal plants (which in turn could lead to unit shutdowns) or to pay its senior debt as it matures. If EME's credit facilities are not replaced, EME's ability to hedge its merchant coal exposure or carry out its trading activities may also be limited. The terms of EME's and its subsidiaries' debt instruments may restrict EME's ability to sell assets or incur secured indebtedness, and EME's subsidiaries' debt instruments may limit EME's ability to seek additional capital, or restructure or refinance debt to satisfy liquidity needs. For further discussion, see "EMG: Liquidity and Capital Resources" in the MD&A.

EME receives tax-allocation payments from Edison International only if, and only to the extent that, EME is included in the consolidated tax returns of Edison International and Edison International is able to utilize tax losses and credits generated by EME. EME may be required to make tax-allocation payments to Edison International.

EME's right to receive tax-allocation payments and the amount of and timing of those payments are dependent on the inclusion of EME in the consolidated income tax returns of Edison International and other factors, including the amount of consolidated taxable income and net operating losses of Edison International, and other tax items of EME, its subsidiaries, and other subsidiaries of Edison International. Edison International has not been able to fully utilize EME's consolidated tax losses and credits as a result of accelerated tax deductions taken by the consolidated group under the Small Business Jobs Act of 2010 and the 2010 Tax Relief Act and SCE's priority over EME in the utilization of available tax benefits. Realization of EME's tax losses and tax credits is not expected to begin again until at least 2013, subject to future changes in tax laws and Edison International's taxable income, and it may take several years before such benefits can be fully utilized. As of December 31, 2011, EME had recorded deferred tax assets of $520 million related to loss carryforwards and unused credits. EME expects to make tax-allocation payments to Edison International during 2012 of approximately $185 million as a result of the reallocation of tax obligations from an expected Edison International consolidated net operating loss in 2011.

These arrangements are subject to the terms of the tax-allocation and payment agreements among Edison International, EME and other Edison International subsidiaries. The agreements under which EME makes and receives tax-allocation payments may be terminated by the immediate parent company at any time, by notice given before the first day of the first year with respect to which the termination is to be effective. However, termination does not relieve any party of any obligations with respect to any tax year beginning prior to the notice. See "EMG: Liquidity and Capital Resources—Intercompany Tax-Allocation Agreement" in the MD&A.

Regulatory and Environmental Risks

The controls imposed on EMG's coal plants as a result of environmental regulations, including the Combined Pollutant Standard may require material expenditures or unit shutdowns.

Capital expenditures relating to required environmental controls for EMG's coal plants (including the CPS, to which all of Midwest Generation's coal-fired generating units are subject) are expected to be significant. In February 2012, EME decided to shut down the Fisk Station by the end of 2012 and the Crawford Station by the end of 2014 and concluded it was less likely to install environmental controls at the Waukegan Station and Joliet Unit 6. EME may ultimately decide to shut down the Waukegan Station and Joliet Unit 6, and possibly other units, rather than make improvements. Unit shutdowns could have an adverse effect on EMG's business, results of operation and financial condition. For more information about EMG's plans for environmental compliance, see "Item 1. Business—Environmental Regulation of Edison International and Subsidiaries—Air Quality—Nitrogen Oxide and Sulfur Dioxide," "Edison International (Consolidated): Liquidity and Capital Resources—Critical Accounting Estimates and Policies" in the MD&A, and "Item 8. Edison International Notes to Consolidated Financial Statements—Note 10. Environmental Developments."

Market Risks

EMG has substantial interests in merchant energy power plants which are subject to market risks related to wholesale energy prices because they operate without long-term power purchase agreements. Wholesale energy prices have substantially declined in recent years.

EMG's merchant energy power plants do not have long-term power purchase agreements. Because the output of these power plants is not committed to be sold under long-term contracts, these projects are subject to market forces which determine the amount and price of energy, capacity and ancillary services sold from the power plants. Unlike most other commodities, electric power can only be stored on a very limited basis and generally must be produced when it is to be used. As a result, the wholesale power markets are subject to significant and unpredictable price fluctuations over relatively short periods of time. Due to the volume of sales into PJM from the coal plants, EMG has concentrated exposure to market conditions and fluctuations in PJM. Prices for power and capacity have declined significantly due largely to lower natural gas prices and have been affected in recent years by increased use of demand response technology, changes in final demand for power during the economic slowdown, and technological developments that have increased access to natural gas shale reserves, resulting in substantial declines in market prices for natural gas which supplies power plants that compete with EMG's coal plants.

Market prices of energy, capacity and ancillary services sold from these power plants are influenced by multiple factors beyond EMG's control, and thus there is considerable uncertainty whether or when current depressed prices will recover. EMG's hedging activities may not cover the entire exposure of its assets or positions to market price volatility, and the level of coverage will vary over time. The effectiveness of EMG's hedging activities may depend on the amount of credit available to post collateral, either in support of performance guarantees or as cash margin, and liquidity requirements may be greater than EMG anticipates or will be able to meet. EMG cannot provide assurance that its hedging strategies will successfully mitigate market risks. For more detail on these matters, see "EMG: Market Risk Exposures—Commodity Price Risk" in the MD&A.

EMG's financial results can be affected by changes in prices, transportation cost, and supply interruptions related to fuel, sorbents, and other commodities used for power generation and emission controls.

In addition to volatile power prices, EMG's business is subject to changes in the cost of fuel, sorbents, and other commodities used for power generation and emission controls, and in the cost of transportation. These costs can be volatile and are influenced by many factors outside of EMG's control. The price at which EMG can sell its energy may not rise or fall at the same rate as a corresponding rise or fall in commodity costs. Operations at the coal plants are dependent upon the availability and affordability of coal which is available only from a limited number of suppliers and which, in the case of Midwest Generation, is transported by rail under a multi-year long-term transportation contract. All of these factors may have an adverse effect on EMG's financial condition and results of operations. See "EMG: Market Risk Exposures—Commodity Price Risk" in the MD&A.

Competition could adversely affect EMG's business

EMG has numerous competitors in all aspects of its business some of whom may have greater liquidity, greater access to credit and other financial resources, lower cost structures, greater ability to withstand losses, larger staffs or more experience than EMG. Multiple participants in the wholesale markets, including many regulated utilities, have a lower cost of capital than most merchant generators and often are able to recover fixed costs through rate base mechanisms, allowing them to build, buy and upgrade generation assets without relying exclusively on market clearing prices to recover their investments. These factors could affect EMG's ability to compete effectively in the markets in which those entities operate. Newer plants owned by EMG's competitors are often more efficient than EMG's facilities and may also have lower costs of operation. Over time, some of EMG's merchant facilities may become obsolete in their markets, or be unable to compete with such plants.

Operating Risks

EMG's capital projects may not be successful.
EMG's capital projects are subject to risks including, without limitation, risks related to financing, construction, permitting,

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and governmental approvals. EME may be required to spend significant amounts before it can determine whether a project is feasible or economically attractive. The timing of such projects may be delayed beyond the date that equipment is ready for installation, in which case EMG may be required to incur material equipment and/or material costs with no deployment plan at delivery. Due to competing capital needs, EMG's further development of its renewable business will depend upon the availability of third-party equity capital.

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

The operation of power generation facilities is a potentially dangerous activity that involves many operating risks, including transmission disruptions and constraints, equipment failures or shortages, and system limitations, degradation and interruption. EMG's operations are also subject to risks of human performance and workforce capabilities. There can be no assurance that EMG's insurance will be sufficient or effective under all circumstances or protect against all hazards to which EMG may be subject, or that insurance coverage will continue to be available on terms similar to those presently available, or at all. EMG has a number of older facilities that are subject to higher risks of failure or outage, and EMG has in the past experienced serial defects in certain models of wind turbines deployed at its wind projects.

Uncertainties in EMG's future operations could affect its ability to attract and retain skilled people.

Uncertainties concerning EMG's future operations could affect its ability to attract and retain qualified personnel with experience in the energy industry. If EMG is unable to successfully attract and retain an appropriately qualified workforce, its results of operations will be negatively affected.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

As a holding company, Edison International does not directly own any significant properties other than the stock of its subsidiaries. The principal properties of SCE are described above under "Item 1. Business—Southern California Edison Company—Properties." Properties of EMG are described above under "—Edison Mission Group Inc.—Properties."

ITEM 3. LEGAL PROCEEDINGS

Midwest Generation New Source Review and Other Litigation

Information about the Midwest Generation New Source Review and Other Litigation appears in "Item 8. Edison International Notes to the Consolidated Financial Statements—Note 9. Commitments and Contingencies—Contingencies."

Homer City New Source Review and Other Litigation

Information about the Homer City New Source Review and Other Litigation appears in "Item 8. Edison International Notes to the Consolidated Financial Statements—Note 9. Commitments and Contingencies—Contingencies."

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Pursuant to Form 10-K's General Instruction G(3), the following information is included as an additional item in Part I:

EXECUTIVE OFFICERS OF THE REGISTRANT

Executive Officer	Age at December 31, 2011	Company Position
Theodore F. Craver, Jr.	60	Chairman of the Board, President and Chief Executive Officer, Edison International
Robert L. Adler	64	Executive Vice President and General Counsel, Edison International
Polly L. Gault	58	Executive Vice President, Public Affairs, Edison International
W. James Scilacci	56	Executive Vice President, Chief Financial Officer and Treasurer, Edison International
Janet T. Clayton	57	Senior Vice President, Corporate Communications, Edison International
Daryl D. David	57	Senior Vice President, Human Resources, Edison International
Bertrand A. Valdman	49	Senior Vice President, Strategic Planning
Mark C. Clarke	55	Vice President and Controller, Edison International
Ronald L. Litzinger	52	President, SCE
Pedro J. Pizarro	46	President, EMG and EME

As set forth in Article IV of Edison International's and the relevant subsidiary's Bylaws, the elected officers of Edison International and its subsidiaries are chosen annually by, and serve at the pleasure of, Edison International and the relevant subsidiary's Board of Directors and hold their respective offices until their resignation, removal, other disqualification from service, or until their respective successors are elected. All of the officers of Edison International and its subsidiaries have been actively engaged in the business of Edison International and its subsidiaries for more than five years, except for Messrs. Adler, David, and Valdman, and Ms. Clayton, and have served in their present positions for the periods stated below. Additionally, those officers who have had other or additional principal positions in the past five years had the following business experience during that period:

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Executive Officers	Company Position	Effective Dates
Theodore F. Craver, Jr.	Chairman of the Board, President and Chief Executive Officer, Edison International	August 2008 to present
	President, Edison International	April 2008 to July 2008
	Chairman of the Board, President and Chief Executive Officer, EMG	November 2005 to March 2008
	Chairman of the Board, President and Chief Executive Officer, EME	January 2005 to March 2008
Robert L. Adler	Executive Vice President and General Counsel, Edison International	August 2008 to present
	Executive Vice President, Edison International	July 2008 to August 2008
	Partner, Munger, Tolles & Olson LLP[1]	January 1978 to June 2008
Polly L. Gault	Executive Vice President, Public Affairs, Edison International	March 2007 to present
	Executive Vice President, Public Affairs, SCE	March 2007 to September 2008
	Senior Vice President, Public Affairs, Edison International and SCE	March 2006 to February 2007
W. James Scilacci	Executive Vice President, Chief Financial Officer and Treasurer, Edison International	August 2008 to present
	Senior Vice President and Chief Financial Officer, EME	March 2005 to July 2008
	Senior Vice President and Chief Financial Officer, EMG	November 2005 to July 2008
Janet T. Clayton	Senior Vice President, Corporate Communication, Edison International	April 2011 to present
	President, Think Cure[2]	Jan 2008 to April 2011
	Assistant Managing Editor, Los Angeles Times[3]	June 2004 to September 2007
Daryl D. David	Senior Vice President, Human Resources, Edison International	June 2009 to present
	Executive Vice President & Chief Human Resources Officer, Washington Mutual, Inc.[4]	May 2000 to October 2008
Bertrand A. Valdman	Senior Vice President, Strategic Planning, Edison International	March 2011 to present
	Executive Vice President, Chief Operating Officer Puget Sound Energy[5]	May 2007 to March 2011
	Senior Vice President, Chief Financial Officer Puget Sound Energy[5]	December 2003 to May 2007
Mark C. Clarke	Vice President and Controller, Edison International	August 2009 to present
	Vice President and Controller, EME	January 2003 to July 2009
Ronald J. Litzinger	President, SCE	January 2011 to present
	Chairman of the Board, President and Chief Executive Officer, EMG and EME	April 2008 to December 2010
	Senior Vice President, Transmission and Distribution, SCE	May 2005 to March 2008
Pedro J. Pizarro	President, EMG and EME	January 2011 to present
	Executive Vice President, Power Operations, SCE	April 2008 to December 2010
	Senior Vice President, Power Procurement, SCE	May 2005 to March 2008

1 Munger, Tolles & Olson LLP is a California-based law firm. Mr. Adler also served as a Co-Managing Partner.

2 Think Cure is a community-based nonprofit organization that raises funds to accelerate collaborate research to cure cancer and is not a parent, affiliate or subsidiary of Edison International.

3 The Los Angeles Times is a daily newspaper published in Los Angeles, California and is not a parent, affiliate or subsidiary at Edison International.

4 Washington Mutual was a bank holding company and the former owner of Washington Mutual Bank and is not a parent, subsidiary or affiliate of Edison International.

5 Puget Sound Energy is a regulated energy utility in Washington State and is not a parent, affiliate or subsidiary of Edison International.

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PART II

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

Edison International Common Stock is traded on the New York Stock Exchange under the symbol "EIX."

Market information responding to Item 5 is included in "Item 8. Edison International Notes to Consolidated Financial Statements—Note 19. Quarterly Financial Data." There are restrictions on the ability of Edison International's subsidiaries to transfer funds to Edison International that materially limit the ability of Edison International to pay cash dividends. Such restrictions are discussed in the MD&A under the heading "Edison International Parent and Other" and in "Item 8. Edison International Notes to Consolidated Financial Statements—Note 5. Debit and Credit Agreements." The number of common stockholders of record of Edison International was 45,430 on February 24, 2011. Additional information concerning the market for Edison International's Common Stock is set forth on the cover page of this report. The description of Edison International's equity compensation plans required by Item 201(d) of Regulation S-K is incorporated by reference to "Part III—Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" of this report.

Issuer Purchases of Securities

The following table contains information about all purchases of Edison International Common Stock made by or on behalf of Edison International in the fourth quarter of 2011.

Period	(a) Total Number of Shares (or Units) Purchased[1]	(b) Average Price Paid per Share (or Unit)[1]	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
October 1, 2011 to October 31, 2011	499,480	$38.84	—	—
November 1, 2011 to November 30, 2011	812,326	$39.46	—	—
December 1, 2011 to December 31, 2011	446,349	$40.71	—	—
Total	1,758,155	$39.60	—	—

1 The shares were purchased by agents acting on Edison International's behalf for delivery to plan participants to fulfill requirements in connection with Edison International's: (i) 401(k) Savings Plan; (ii) Dividend Reinvestment and Direct Stock Purchase Plan; and (iii) long-term incentive compensation plans. The shares were purchased in open-market transactions pursuant to plan terms or participant elections. The shares were never registered in Edison International's name and none of the shares purchased were retired as a result of the transactions.

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Comparison of Five-Year Cumulative Total Return

	At December 31,					
	2006	2007	2008	2009	2010	2011
Edison International	$100	$120	$74	$84	$96	$107
S & P 500 Index	100	105	66	84	97	99
Philadelphia Utility Index	100	119	87	95	101	120

Note: Assumes $100 invested on December 31, 2006 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.

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ITEM 6. SELECTED FINANCIAL DATA

Selected Financial Data: 2007 – 2011

(in millions, except per-share amounts)	2011	2010	2009	2008	2007
Edison International and Subsidiaries					
Operating revenue	$12,760	$12,409	$12,361	$14,112	$12,868
Operating expenses	$12,440	$10,283	$10,963	$11,549	$10,359
Income from continuing operations	$24	$1,303	$952	$1,348	$1,307
Net income	$21	$1,307	$945	$1,348	$1,305
Net income (loss) attributable to common shareholders	$(37)	$1,256	$849	$1,215	$1,098
Weighted-average shares of common stock outstanding (in millions)	326	326	326	326	326
Basic earnings (loss) per share:					
Continuing operations	$(0.10)	$3.83	$2.61	$3.69	$3.34
Discontinued operations	$(0.01)	$0.01	$(0.02)	$—	$(0.01)
Total	$(0.11)	$3.84	$2.59	$3.69	$3.33
Diluted earnings per share	$(0.11)	$3.82	$2.58	$3.68	$3.31
Dividends declared per share	$1.285	$1.265	$1.245	$1.225	$1.175
Total assets	$48,039	$45,530	$41,444	$44,615	$37,523
Long-term debt	$13,689	$12,371	$10,437	$10,950	$9,016
Preferred and preference stock of utility	$1,029	$907	$907	$907	$915
Common shareholders' equity	$10,055	$10,583	$9,841	$9,517	$8,444

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.

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

EDISON INTERNATIONAL OVERVIEW

Highlights of Operating Results

(in millions)	2011	2010	Change	2009
Net Income (Loss) attributable to Edison International				
SCE	$1,085	$1,040	$45	$1,226
EMG	(1,089)	224	(1,313)	(395)
Edison International Parent and Other	(33)	(8)	(25)	18
Edison International Consolidated	(37)	1,256	(1,293)	849
Less: Non-Core Items				
Asset impairments and other charges:				
EMG – Homer City Plant	(623)	—	(623)	—
EMG – Fisk, Crawford and Waukegan Stations	(386)	—	(386)	—
EMG – Wind related charges and other	(41)	—	(41)	—
EMG – Write-down of net investment in aircraft leases	(16)	—	(16)	—
EMG – Write-down of capitalized costs	—	(24)	24	—
EMG – Gain on sale of March Point	5	—	5	—
Global Settlement:				
SCE	—	95	(95)	306
EMG[1]	—	52	(52)	(610)
Edison International Parent and Other	—	28	(28)	50
SCE – tax impact of health care legislation	—	(39)	39	—
SCE – regulatory items	—	—	—	46
Edison International Parent and Other – deferred taxes	(21)	—	(21)	—
EMG discontinued operations	(3)	4	(7)	(7)
Total non-core items	(1,085)	116	(1,201)	(215)
Core Earnings (Losses)				
SCE	1,085	984	101	874
EMG	(25)	192	(217)	222
Edison International Parent and Other	(12)	(36)	24	(32)
Edison International Consolidated	$1,048	$1,140	$(92)	$1,064

[1] Includes termination of Edison Capital's cross-border leases in 2009 and state tax impact of the Global Settlement with the IRS.

Edison International's earnings are prepared in accordance with generally accepted accounting principles used in the United States. Management uses core earnings by principal operating subsidiary internally for financial planning and for analysis of performance. Core earnings (losses) by principal operating subsidiary are also used when communicating with analysts and investors regarding our earnings results to facilitate comparisons of the Company's performance from period to period. Core earnings (losses) are a non-GAAP financial measure and may not be comparable to those of other companies. Core earnings (losses) are defined as earnings attributable to Edison International shareholders less income or loss from discontinued operations and income or loss from significant discrete items that management does not consider representative of ongoing earnings, such as: exit activities, including lease terminations, sale of certain assets, early debt extinguishment costs and other activities that are no longer continuing; asset impairments and certain tax, regulatory or legal settlements or proceedings.

SCE's 2011 core earnings increased $101 million primarily due to rate base growth.

EMG's 2011 core earnings declined $217 million due to lower realized energy and capacity prices along with lower

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generation from merchant coal plants, higher plant maintenance costs from outages, higher interest expense related to renewable projects, and lower trading income.

Edison International Parent and Other 2011 core results changed primarily due to higher tax benefits in 2011 compared to 2010.

Consolidated non-core items for Edison International included:

- An after-tax earnings charge of $1.09 billion ($1.76 billion pre-tax) recorded in the fourth quarter of 2011 resulting primarily from the impairment the Homer City, Fisk, Crawford and Waukegan power plants, wind related charges, write-down of a net investment in aircraft leases with American Airlines, and the impact on Edison International consolidated deferred income taxes resulting from an increase in the state apportionment rates due to such impairment charges as discussed further below and in "Item 8. Edison International Notes to Consolidated Financial Statements—Note 16. Asset Impairments, Lease Terminations and Other."
- An after tax earnings benefit of $175 million recorded in 2010 relating to the California impact of the federal Global Settlement resulting from acceptance by the California Franchise Tax Board of tax positions finalized with the IRS in 2009 and receipt of the final interest determination from the Franchise Tax Board. For further discussion of the Global Settlement, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 7. Income Taxes."
- An after-tax earnings charge of $39 million recorded in 2010 to reverse previously recognized federal tax benefits eliminated by federal health care legislation enacted in 2010. The health care law eliminated the federal tax deduction for retiree health care costs to the extent those costs are eligible for federal Medicare Part D subsidies.
- An after-tax earnings charge of $24 million ($40 million pre-tax) recorded in 2010 resulting from the write-off of capitalized engineering and other costs related to a change in air emission control technology selection at EMG's Powerton Station.

See "SCE: Results of Operations" for discussion of SCE results of operations, including a comparison of 2010 results to 2009. Also, see "EMG: Results of Operations" for discussion of EMG results of operations, including a comparison of 2010 results to 2009.

Management Overview of SCE

SCE's core mission is to deliver safe, reliable and affordable electric service to its customers. Accomplishing this mission requires balancing competing priorities, including public policies regarding air and water quality, energy efficiency and renewable energy and the need to replace aging infrastructure. The accumulation of several major policy mandates is expected to add significantly to the cost of electric service, which could cause a growing number of customers to seek to self-generate their power. Choices by customers to self-generate results in fewer kilowatt hour sales to absorb the increasing costs of the electrical system, further increasing rates for SCE's other customers. Working with policy makers to balance competing priorities, a key focus of SCE is to manage the costs that drive increases in electricity rates while delivering safe and reliable electric service to its customers.

2012 CPUC General Rate Case

SCE filed its 2012 GRC application in November 2010. In October 2011, SCE submitted updated testimony to reflect changes in escalation rates, known changes due to governmental actions and changes in the timing of recovery for nuclear refueling outages at San Onofre, which taken together changed its requested 2012 base rate revenue requirement to $6.3 billion. SCE's updated request, after considering the effects of sales growth and including the impacts of reducing SCE's solar program as approved by the CPUC, would result in incremental customer base rate increases of $809 million, $117 million and $513 million in 2012, 2013 and 2014, respectively.

The Division of Ratepayer Advocates ("DRA") recommended that SCE's requested 2012 base rate revenue requirement be decreased by approximately $850 million, comprised of approximately $630 million in operation and maintenance expense reductions and approximately $220 million in capital-related revenue requirement reductions. The Utility Reform Network ("TURN") and other intervenors recommended an additional $610 million revenue requirement reduction, beyond the DRA adjustments, primarily capital-related in nature, as well as disallowances of recorded capital investments for specific projects. Intervenors have also recommended changes to SCE's proposed post-test year ratemaking methodology to be used for 2013 and 2014 as well as limiting the recovery amount of SCE's pension costs. A final decision on the GRC is expected in the first half of 2012. The CPUC has authorized the establishment of a GRC memorandum account, which will make the 2012 revenue requirement ultimately adopted by the CPUC effective as of January 1, 2012. Recognition of the revenue for the period January 1, 2012 through the date of a final decision, as well as any delays in certain expenditures, may impact the timing of earnings in 2012.

FERC Formula Rates

The FERC has accepted, subject to refund and settlement procedures, SCE's request to implement formula rates as a means to determine SCE's FERC transmission revenue requirement effective January 1, 2012. The formula rates include revenue requirements related to construction work in progress ("CWIP") that was previously recovered through a separate mechanism. SCE estimates its total 2012 FERC weighted average ROE will be 11.1%, including the previously authorized 50 basis point incentive for CAISO participation and individual authorized project incentives. The actual weighted average ROE and rate base is dependent upon the amount and timing of capital expenditures among FERC incentive and non-incentive projects. SCE's request proposed the adoption of a specific formula to calculate a forecasted annual revenue requirement that is used to establish rates and is trued-up annually to allow SCE to recover its actual revenue requirement, including its actual cost of service, actual rate base and the authorized return on investment. SCE's request also allows SCE to make single-issue rate filings requesting changes to certain elements of the formula, including the base ROE, depreciation rates and the retail rate structure. SCE and the other parties to the proceeding are currently in settlement negotiations.

Capital Program

During 2011, SCE continued execution of its capital investment program. Total capital expenditures (including accruals) were $3.9 billion in 2011 compared to $3.8 billion in 2010. The level of future spending is significantly dependent on a final outcome of SCE's 2012 GRC decision and the timing, scope and approvals of major transmission projects. SCE's capital program for 2012 – 2014 is focused primarily in the following areas:

- Maintaining reliability and expanding the capability of SCE's transmission and distribution system.
- Upgrading and constructing new transmission lines and substations for system reliability and increased access to renewable energy, including the Tehachapi, Devers-Colorado River, Eldorado-Ivanpah, and Red Bluff projects.
- Completing installation of digital meters in households and small businesses, referred to as EdisonSmartConnect™. Through 2011, SCE installed 3.8 million meters and plans to install the remaining 1.2 million meters during 2012.
- Generation capital projects for nuclear and hydro-electric plants.

SCE forecasts capital expenditures in the range of $11.8 billion to $13.2 billion for 2012 – 2014. Actual capital spending will be affected by: changes in regulatory, environmental and engineering design requirements; permitting and project delays; cost and availability of labor, equipment and materials; and other factors as discussed further under "SCE: Liquidity and Capital Resources—Capital Investment Plan." SCE has experienced significant cost pressures on its Tehachapi and Devers-Colorado River Transmission Projects, primarily related to environmental monitoring and mitigation costs, scope changes and schedule delays. Currently, SCE is completing the final engineering design for these projects and expects to file revised cost estimates with the CPUC later this year. Subject to further permitting and schedule delays, SCE has revised its direct capital expenditure estimates for the Tehachapi Project to $2.5 billion from $2.1 billion and revised its estimates for the Devers-Colorado River Project to $860 million from $649 million. The Tehachapi Project may be further impacted by issues related to aviation marking and lighting and community opposition to portions of the line, as further discussed in "SCE: Liquidity and Capital Resources—Capital Investment Plan." Capital program cost increases have been partially offset by expenditures for other transmission reliability projects, which were deferred due to delays from once-through cooling requirements for coastal generating plants. SCE plans to utilize cash generated from its operations, tax benefits and issuance of additional debt and preferred equity to fund its capital needs.

Management Overview of EMG

EMG's competitive power generation business primarily consists of the generation and sale into the PJM market of energy and capacity from merchant coal-fired power plants and a portfolio of natural gas and wind projects. EMG's operating results were significantly lower in 2011 compared to 2010 due to lower realized energy and capacity prices and generation at the coal plants. Power prices fell in the fourth quarter of 2011 and have continued to fall in 2012, driven by an abundance of low-priced natural gas, weather conditions and a slow economic recovery. Moreover, the abundance of low-priced natural gas has resulted in increased competition from natural gas-fired generating units in the markets in which Midwest Generation operates, and generation from Midwest Generation's plants has been correspondingly affected. Also at the end of 2011, a favorable long-term rail contract that supplied Midwest Generation's fleet expired and was replaced by a higher priced contract. EMG expects that Midwest Generation's average fuel cost ($/MWh) will increase by approximately one-third in 2012. Furthermore, Homer City is engaged in discussions with the owner-lessors regarding funding of retrofit expenditures for the Homer City plant that, if successful in providing funding, will likely result in EME's loss of substantially all beneficial economic interest in and material control of the Homer City plant. Finally, as discussed below, EMG recorded significant impairment charges during the fourth quarter of 2011.

At December 31, 2011, EME had corporate cash and cash equivalents of $951 million and $498 million of available borrowing capacity under its $564 million revolving credit facility maturing in June 2012 and Midwest Generation had cash and cash equivalents of $213 million and $497 million of available borrowing capacity under its $500 million credit facility maturing in June 2012. Subsequent to the end of the fiscal year, EME terminated its revolving credit facility, and there can be no assurance that Midwest Generation will be eligible to draw on its credit facility prior to maturity. Any replacements of these credit lines will likely be on less favorable terms and conditions, and there is no assurance that EME will, or will be able to, replace these credit lines or any portion of them. EME had $3.7 billion of unsecured notes outstanding at December 31, 2011, $500 million of which mature in 2013.

Unless energy and capacity prices increase, EMG expects that it will incur further reductions in cash flow and losses in years subsequent to 2012 as well as in 2012, and a continuation of these adverse trends coupled with pending debt maturities and the need to retrofit its plants to comply with governmental regulations will strain EMG's liquidity. To address such scenario, EMG would need to consider all options available to it, including potential sales of assets or restructurings or reorganization of the capital structure of EMG and its subsidiaries. EMG's current business plans are focused on liquidity and operating effectively through the current commodity price cycle and on environmental compliance as described below.

Midwest Generation Environmental Compliance Plans and Costs

During 2011, Midwest Generation continued to advance necessary activities for NO_x and SO_2 controls to meet the requirements of the CPS. Midwest Generation does not anticipate a material change to its current approach in order to comply with the MATS rule. Midwest Generation expects to continue to develop and implement a compliance program that includes the operations of ACI systems, upgrades to particulate removal systems and the use of dry sorbent injection, combined with its use of low sulfur PRB coal, to meet emissions limits for criteria pollutants, such as NO_x and SO_2 as well as for hazardous air pollutants, such as mercury, acid gas and non-mercury metals.

A significant decline in power prices from September 30, 2011, combined with new environmental regulations and public policy pressure on coal generation have resulted in continuing uncertainties for merchant coal-fired power plants. Decisions regarding whether or not to proceed with retrofitting any particular remaining units to comply with CPS requirements for SO_2 emissions, including those that have received permits, are subject to a number of factors, such as market conditions, regulatory and legislative developments, liquidity and forecasted commodity prices and capital and operating costs applicable at the time decisions are required or made. Midwest Generation may also elect to shut down units, instead of installing controls, to be in compliance with the CPS. Decisions about any particular combination of retrofits and shutdowns Midwest Generation may ultimately employ also remain subject to conditions applicable at the time decisions are required or made. Final decisions on whether to install controls, to install particular kinds of controls, and to actually expend capital or continue with the expenditure of capital will be made as required, subject to the requirements of the CPS and other applicable regulations. In February 2012, Midwest Generation decided to shut down the Fisk Station by the end of 2012 and the Crawford Station by the end of 2014 and concluded it was less likely to retrofit the Waukegan Station rather than the larger Powerton, Joliet and Will County Stations. As a result, EMG recorded an impairment charge of $640 million at December 31, 2011 related to the Crawford, Fisk and Waukegan Stations. For further discussion, see "Edison International (Consolidated): Liquidity and Capital Resources—Critical Accounting Estimates and Policies—Impairment of Long-Lived Assets—Application to Midwest Generation Stations" and "Item 8. Edison International Notes to Consolidated Financial Statements—Note 16. Asset Impairments, Lease Terminations and Other." Units that are not retrofitted may continue to operate until required to shut down by applicable regulations or operate with reduced output.

In connection with its decision to close the Fisk and Crawford Stations, Midwest Generation entered into a Memorandum of Understanding with the City of Chicago, acting through the Commissioner of Health, which acknowledges that the cessation of coal-fired electric generation at the Fisk and Crawford Stations will achieve the objectives of the proposed Chicago Clean Power Ordinance without a need to pass the proposed Clean Power Ordinance or similar ordinances (recognizing that such agreement cannot bind the Chicago City Council or its members). Midwest Generation and the City of Chicago have also agreed to collaborate with key stakeholders to consider potential future uses, ownership and sources of external funding to transition the sites for such uses. The closure of the Fisk and Crawford Stations will be subject to review for reliability by PJM Interconnection LLC, the regional transmission organization that controls the area where these plants are located. In total, Midwest Generation estimates 150 to 180 employees will be affected. The timing and amount of severance benefits, if any, will be determined after completion of review of personnel based on seniority and other factors and, in the case of the Crawford Station, the amount may be affected by the timing of the plant closure. Other obligations related to the Fisk and Crawford Stations could be affected by the plant closing, including sales of capacity, for which Midwest Generation is unable to reasonably estimate the impact, or range of impacts, that could be incurred. Midwest Generation does not expect to incur future capital expenditures to close these plants.

Based on work to date, Midwest Generation estimates the cost of retrofitting the large stations (Powerton, Joliet Units 7 and 8 and Will County) using dry scrubbing with sodium-based sorbents to comply with CPS requirements for SO_2 emissions, and the associated upgrading of existing particulate removal systems, would be up to approximately $628 million. The cost of retrofitting Joliet Unit 6 is not included in the large unit amounts as it is less likely that Midwest Generation will make retrofits for this unit. The estimated cost of retrofitting Joliet Unit 6, if made, would be approximately $75 million, while the estimated cost of retrofitting the Waukegan Station, if made, would be approximately $160 million. For further discussion related to EMG's impairment policy on the unit of account, see "Edison International (Consolidated): Liquidity and Capital Resources—Critical Accounting Estimates and Policies—Impairment of Long-Lived Assets."

In February 2012, Midwest Generation received an extension of its permit to install a dry sorbent injection system at the Powerton Station.

Homer City Lease

Homer City engaged a financial advisor and conducted a bidding process to obtain capital funding from third parties during the second half of 2011 to partially finance the installation of the environmental improvements. During the fourth quarter of 2011, such efforts failed to obtain sufficient interest from market participants necessary to fund the capital needed to make such improvements under the current lease arrangement. Homer City does not currently have sufficient capital and does not expect to generate sufficient funds from operations to complete retrofits. EMG is under no legal obligation to, and has chosen not to, provide funding. Restrictions under the agreements entered into as part of Homer City's 2001 sale-leaseback transaction affect, and in some cases significantly limit or prohibit, Homer City's ability to incur indebtedness or make capital expenditures. Consequently, Homer City's ability to install environmental compliance equipment will be dependent on funding from the owner-lessors or third parties. Homer City is currently engaged in discussions with the owner-lessors regarding the potential for such funding. EMG expects that the outcome of any such discussions, if successful in providing funding for the Homer City plant, will likely result in EMG's loss of substantially all beneficial economic interest in and material control of the Homer City plant. Failure to resolve the source of funding of necessary capital expenditures for the Homer City plant could result in Homer City's default under the lease agreements giving rise to remedies for the owner-lessors and secured lease obligation bondholders, which could include foreclosing on the leased assets, the general partner of Homer City, or both.

There is no assurance that an agreement will be reached with the owner-lessors or the existing secured lease obligation bondholders on funding the capital improvements. Homer City believes it is unlikely to meet the covenant requirements of its sale-leaseback documents relating to the payment of equity rent at April 1, 2012 and will be unable to make the required equity rent payment. There is no assurance that subsequent rent payments will be made. Under the sale-leaseback documents, rent payments are comprised of two components, senior rent and equity rent. Senior rent is used exclusively for debt service to secured lease obligation bondholders, while equity rent is paid to the owner-lessors. In order to pay equity rent, among other requirements, Homer City must meet historical and projected senior rent service coverage ratios of 1.7 to 1 (subject to reduction to 1.3 to 1 under certain circumstances). A failure to pay equity rent does not entitle the owner-lessors to foreclose upon Homer City's leasehold interest, but it does result in the suspension of Homer City's ability to make permitted distributions. Moreover, Homer City would be permanently restricted in its ability to make permitted distributions if a failure to pay equity rent when due was not cured within nine months, or even if cured, occurred more than one additional time during the term of the lease. Homer City is not subject to any minimum historical and projected senior rent service coverage ratios except as conditions to distributions and equity rent payments. Also, failure by Homer City to pay equity rent when due in April 2012 could trigger termination of the $48 million senior rent reserve letter of credit. Homer City would then be required to fund the senior rent reserve, and failure to do so could entitle counterparties to seek available remedies under the sale-leaseback documents, including termination or foreclosure upon the leasehold interest. As a result of the expectation that EMG is likely to lose substantially all beneficial economic interest in and material control of the Homer City plant, EMG recorded an impairment charge of $1.03 billion for the fourth quarter of 2011. For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 16. Asset Impairments, Lease Terminations and Other."

Included in the consolidated financial statements are the assets and liabilities related to Homer City. In the event that EMG no longer controls Homer City, EMG will record a loss on disposition of assets and liabilities and likely classify Homer City as a discontinued operation. The loss on disposition will be determined based on the assets and liabilities at the date of disposition and an assessment whether any ongoing contingencies exist. For further discussion, see "Edison International (Consolidated): Liquidity and Capital Resources—Critical Accounting Estimates and Policies—Impairment of Long-Lived Assets—Application to Homer City Plant" and "Item 8. Edison International Notes to Consolidated Financial Statements—Note 16. Asset Impairments, Lease Terminations and Other."

As a result of the financial outlook of Homer City, as previously discussed, EMG's subsidiary, EMMT, has ceased to enter into hedging activities related to future power sales, but continues to enter into energy and capacity transactions on behalf of Homer City pursuant to an intercompany agreement. Those transactions are generally back-to-back transactions in which EMMT enters into a transaction with a third party as a principal and then enters into an equivalent transaction with Homer City. In the case of capacity, EMMT has sold Homer City capacity in the annual PJM base residual auctions through May 2015. If Homer City were to default on its obligations to supply capacity, then EMMT would be liable to PJM to supply that capacity, and failure to do so would expose EMMT to penalties under the PJM tariffs. If one or more of the Homer City units were to be unavailable as a capacity resource and EMMT did not fulfill this obligation through market transactions, then EMMT would be required to refund any capacity payments received and would be assessed by PJM a penalty equal to the greater of 20% of the capacity payments or $20 per MW-day.

EMG's Renewable Energy Activities

Recent developments related to EMG renewable financing and development activities include:

- On December 21, 2011, EMG's subsidiary, EME closed a $242 million portfolio financing of three contracted wind projects representing 204 megawatts of generation capacity previously funded entirely with equity. Funding available in the amount of $110 million from the term loan facility, net of transaction costs, was distributed to EME in 2011 and approximately $95 million, net of transaction costs, of available funds is expected to be distributed in the first quarter of 2012 when the Pinnacle project achieves certain completion milestones.
- As part of its plan to obtain third-party equity capital to finance the development of a portion of EMG's wind portfolio, on February 13, 2012, Edison Mission Wind sold its indirect equity interests in the Cedro Hill wind project (150 MW in Texas), the Mountain Wind Power I project (61 MW in Wyoming) and the Mountain Wind Power II project (80 MW in Wyoming) to a new venture, Capistrano Wind Partners. Outside investors provided $238 million of the funding. Capistrano Wind Partners also agreed to acquire the Broken Bow I wind project (80 MW in Nebraska) and the Crofton Bluffs wind project (40 MW in Nebraska) for consideration expected to include $141 million from the same outside investors upon the satisfaction of specified conditions, including commencement of commercial operation and completion of project debt financing. The proceeds from outside investors net of costs on the projects to be completed are expected to be distributed to EMG and available for general corporate purposes. For additional information, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 3. Variable Interest Entities—Categories of Variable Interest Entities—Projects or Entities that are Consolidated."

During the fourth quarter of 2011, EMG significantly reduced development of renewable energy projects to conserve cash and in light of more limited market opportunities. As a result, EMG reduced staffing and has undertaken efforts to reduce funding joint development projects, thereby reducing the development pipeline of potential wind projects to a projected installed capacity to approximately 1,300 megawatts. These changes triggered charges of $34 million. In addition, management has reviewed the Storm Lake project and four small wind projects in Minnesota, and based on an expected future increase in operating costs and declines in long-term power prices that the projects could potentially realize following the term of the power purchase agreements, EMG has recorded an impairment charge of $30 million. For additional information on renewable energy projects, see "EMG: Liquidity and Capital Resources—Capital Investment Plan," "Edison International (Consolidated): Critical Accounting Estimates and Policies—Impairment of Long-Lived Assets—Application to Selected Wind Projects," and "Item 8. Edison International Notes to Consolidated Financial Statements—Note 16. Asset Impairments, Lease Terminations and Other."

Environmental Developments

For a discussion of environmental developments, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 10. Environmental Developments."

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SOUTHERN CALIFORNIA EDISON COMPANY

RESULTS OF OPERATIONS

SCE's results of operations are derived mainly through two sources:

- Utility earning activities – representing revenue authorized by the CPUC and FERC which is intended to provide SCE a reasonable opportunity to recover its costs and earn a return on its net investment in generation, transmission and distribution assets. The annual revenue requirements are comprised of forecasted operation and maintenance costs, depreciation, taxes and a return consistent with the capital structure. Also, included in utility earnings activities are revenues or penalties related to incentive mechanisms, other operating revenue, and regulatory charges or disallowances, if any.
- Utility cost-recovery activities – representing CPUC- and FERC-authorized balancing accounts which allow for recovery of specific project or program costs incurred or provide for mechanisms to track and recover or refund differences in forecasted and actual amounts, subject to reasonableness review or compliance with upfront standards.

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The following table is a summary of SCE's results of operations for the periods indicated. The presentation below separately identifies utility earning activities and utility cost-recovery activities.

(in millions)	2011 Utility Earning Activities	2011 Utility Cost-Recovery Activities	2011 Total Consolidated	2010 Utility Earning Activities	2010 Utility Cost-Recovery Activities	2010 Total Consolidated	2009 Utility Earning Activities	2009 Utility Cost-Recovery Activities[1,2]	2009 Total Consolidated
Operating revenue	$5,902	$4,675	$ 10,577	$5,606	$4,377	$ 9,983	$5,303	$ 4,662	$ 9,965
Fuel and purchased power	—	3,356	3,356	—	3,293	3,293	—	3,472	3,472
Operations and maintenance	2,208	1,179	3,387	2,271	1,020	3,291	2,111	1,043	3,154
Depreciation decommissioning and amortization	1,294	132	1,426	1,213	60	1,273	1,124	54	1,178
Property taxes and other	277	8	285	260	3	263	244	—	244
Gain on sale of assets	—	—	—	—	(1)	(1)	—	(1)	(1)
Total operating expenses	3,779	4,675	8,454	3,744	4,375	8,119	3,479	4,568	8,047
Operating income	2,123	—	2,123	1,862	2	1,864	1,824	94	1,918
Net interest expense and other	(378)	—	(378)	(330)	(2)	(332)	(298)	—	(298)
Income before income taxes	1,745	—	1,745	1,532	—	1,532	1,526	94	1,620
Income tax expense	601	—	601	440	—	440	249	—	249
Net income	1,144	—	1,144	1,092	—	1,092	1,277	94	1,371
Net income attributable to noncontrolling interest	—	—	—	—	—	—	—	94	94
Dividends on preferred and preference stock	59	—	59	52	—	52	51	—	51
Net income available for common stock	$1,085	$—	$ 1,085	$1,040	$—	$ 1,040	$1,226	$ —	$ 1,226
Core Earnings[3]			$ 1,085			$ 984			$ 874
Non-Core Earnings:									
Global tax settlement			—			95			306
Tax impact of health care legislation			—			(39)			—
Regulatory items			—			—			46
Total SCE GAAP Earnings			$ 1,085			$ 1,040			$ 1,226

1 Effective January 1, 2010, SCE deconsolidated the Big 4 projects and therefore these projects are reflected in 2009 activities only (see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 3. Variable Interest Entities" for further discussion).

[2] Effective July 1, 2009, SCE transferred Mountainview Power Company, LLC to SCE. As a result of the transfer and for comparability purposes, Mountainview's 2009 activity was reclassified from cost-recovery activities to utility earning activities consistent with the revised recovery mechanism.

[3] See use of Non-GAAP financial measures in "Edison International Overview—Highlights of Operating Results."

Utility Earning Activities

2011 vs. 2010

Utility earning activities were primarily affected by the following:

- Higher operating revenue of $296 million primarily due to the following:
  - $135 million increase primarily due to a $215 million (4.35%) increase in 2011 authorized revenue approved in the 2009 CPUC GRC decision. The 2011 increase was partially offset by reductions of $80 million mainly resulting from revenue recognized in 2010 associated with the recovery of San Onofre Unit 3 scheduled outage costs with no comparable amount in 2011.

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- $95 million increase in FERC-related revenue primarily resulting from the inclusion of capital expenditures related to the Tehachapi Transmission Project in rate base.
- $25 million increase in capital-related revenue requirements related to the San Onofre steam generator replacement project and a $20 million increase for the EdisonSmartConnect™ project.
- $20 million increase related to recovery of legal costs incurred between 2004 and 2009 in support of SCE's efforts to obtain generator refunds related to claims arising out of the energy crisis in California in 2000 – 2001.
- Lower operation and maintenance expense of $63 million primarily due to costs incurred in 2010 related to the San Onofre Unit 3 scheduled outage.
- Higher depreciation, decommissioning and amortization expense of $81 million primarily related to increased transmission and distribution investments.
- Higher net interest expense and other of $48 million primarily due to higher outstanding balances on long-term debt. For details of other income and expenses, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 17. Other Income and Expenses."
- Higher income taxes primarily due to an increase in income as well as benefits recorded in 2010 related to the Global Settlement. See "—Income Taxes" below for more information.

2010 vs. 2009

Utility earning activities were primarily affected by the following:

- Higher operating revenue of $303 million primarily due to the following:
- $190 million increase primarily due to a 4.25% increase in 2010 authorized revenue approved in the 2009 CPUC GRC decision.
- $55 million increase in FERC-related revenue, primarily due to the implementation of SCE's 2010 and 2009 FERC rate cases effective March 1, 2010 and March 1, 2009, respectively.
- $25 million increase in capital-related revenue requirements related to the San Onofre steam generator replacement project and a $20 million increase for the EdisonSmartConnect™ project.
- Higher operation and maintenance expense of $160 million primarily due to the following:
- $75 million of higher expenses to support company growth programs, including new information technology system requirements and facility maintenance.
- $45 million of higher transmission and distribution expenses to support system reliability and infrastructure replacement, right of way costs; preventive maintenance work, technical training and line clearing.
- $15 million of higher generation expenses primarily from a $25 million increase from the San Onofre Unit 2 and 3 scheduled outages, including $10 million of additional work identified during the Unit 2 scheduled outage, and a $10 million increase primarily due to overhaul and outage costs at Four Corners. These increases were partially offset by a $20 million decrease resulting from 2009 scheduled outages at the Mountainview power plant.
- $15 million of higher expense related to general liability and property insurance due to higher premiums for wildfire coverage.
- Higher depreciation expense of $89 million primarily related to increased capital expenditures, including capitalized software costs.
- Higher net interest expense and other of $32 million primarily due to:
- Lower other income of $19 million primarily related to a decrease in AFUDC – equity earnings due to the transfer of the Mountainview power plant to utility rate base in the third quarter of 2009 partially offset by an increase in AFUDC – equity resulting from a higher capitalization rate and level of construction in progress associated with SCE's capital expenditure plan.
- Higher interest expense of $7 million primarily due to higher outstanding balances on long-term debt.

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See "—Income Taxes" below for discussion of higher income taxes during 2010 compared to the same period in 2009.

Utility Cost-Recovery Activities

2011 vs. 2010

Utility cost-recovery activities were primarily affected by the following:

- Higher purchased power expense of $59 million primarily driven by the cost to replace CDWR contracts that expired in 2011, which were not previously recorded as an SCE cost but impacted customer bills (see "—Supplemental Operating Revenue Information" below), and higher costs associated with renewable contracts. The increase was partially offset by increased purchased power in 2010 during the outages at San Onofre and Four Corners.
- Higher operation and maintenance expense of $159 million including $75 million of increased energy efficiency program costs and $40 million related to the EdisonSmartConnect™ project.
- Higher depreciation, decommissioning and amortization expense of $72 million including $35 million related to the EdisonSmartConnect™ project and $25 million related to the San Onofre steam generator replacement project.

2010 vs. 2009

Utility cost-recovery activities exclude the impact of the consolidation of the Big 4 projects in 2009 for comparability purposes. The following amounts were excluded for 2009: $370 million for purchased power expense to reflect the elimination of sales between the VIEs and SCE; $368 million for fuel expense; and $94 million for operation and maintenance expense. Utility cost-recovery activities were primarily affected by:

- Lower purchased power expense of $191 million primarily related to lower realized losses on economic hedging activities ($156 million in 2010 compared to $344 million in 2009) reflecting the impact of higher natural gas prices in 2010 and changes in SCE's hedge portfolio mix.
- Higher operation and maintenance expense of $71 million primarily due to an increase in spending for various public purpose programs.

Supplemental Operating Revenue Information

SCE's retail billed and unbilled revenue (excluding wholesale sales and balancing account over/undercollections) was $10.0 billion for both 2011 and 2010 and $9.5 billion for 2009. The 2011 revenue reflects:

- a rate decrease of $408 million resulting from a rate adjustment beginning on June 1, 2011, primarily reflecting the refund of over collected fuel and power procurement-related costs, offset by
- a sales volume increase of $393 million primarily due to SCE providing power that was previously provided by CDWR contracts which expired in 2011.

The 2010 revenue reflects:

- a rate increase of $777 million mainly due to the implementation of the CPUC 2009 GRC decision and approved FERC transmission rate changes, partially offset by
- a sales volume decrease of $255 million primarily due to milder weather experienced during 2010 compared to the same period in 2009 and continuing recessionary effects.

As a result of the CPUC-authorized decoupling mechanism, SCE earnings are not affected by changes in retail electricity sales (see "Item 1. Business—Overview of Ratemaking Process").

SCE remits to CDWR and does not recognize as revenue the amounts that SCE bills and collects from its customers for electric power purchased and sold by the CDWR to SCE's customers, as well as CDWR bond-related costs and a portion of direct access exit fees. The amounts collected and remitted to CDWR were $1.1 billion, $1.2 billion and $1.8 billion for years ended December 31, 2011, 2010 and 2009, respectively. All CDWR power contracts allocated to SCE by the CPUC had expired by the end of 2011. SCE's revenue and related purchased power expense is expected to increase in 2012 as these CDWR contracts are replaced by new power purchase agreements entered into by SCE.

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Effective January 1, 2010, the CDWR-related rates were decreased to reflect lower power procurement expenses and a refund of operating reserves that CDWR releases as its contracts terminate. Approximately $440 million is expected to be refunded to SCE customers through lower CDWR rates in 2012.

Income Taxes

The table below provides a reconciliation of income tax expense computed at the federal statutory income tax rate to the income tax provision.

	Years ended December 31,		
(in millions)	2011	2010	2009
Income from continuing operations before income taxes	$1,745	$1,532	$1,620
Net income attributable to noncontrolling interests in the Big 4 projects	—	—	(94)
Adjusted income from continuing operations before income taxes	$1,745	$1,532	$1,526
Provision for income tax at federal statutory rate of 35%	$611	$536	$534
Increase (decrease) in income tax from:			
Items presented with related state income tax, net			
Global settlement related[1]	—	(95)	(306)
Change in tax accounting method for asset removal costs[2]	—	(40)	—
State tax – net of federal benefit	80	59	67
Health care legislation[3]	—	39	—
Property-related	(76)	(47)	(64)
Other	(14)	(12)	18
Total income tax expense from continuing operations	$601	$440	$249
Effective tax rate	34.4%	28.7%	16.3%

1 Edison International and the IRS finalized the terms of a Global Settlement on May 5, 2009. The Global Settlement resolved all of SCE's federal income tax disputes and affirmative claims through tax year 2002. During 2009, SCE recorded after-tax earnings of approximately $306 million. During 2010, SCE recognized a $95 million earnings benefit from the acceptance by the California Franchise Tax Board of the tax positions finalized in 2009 and receipt of the final interest determination from the Franchise Tax Board.

2 During 2010, the IRS approved SCE's request to change its tax accounting method for asset removal costs primarily related to its infrastructure replacement program. As a result, SCE recognized a $40 million earnings benefit (of which $28 million relates to asset removal costs incurred prior to 2010) from deducting asset removal costs earlier in the construction cycle. These deductions were recorded on a flow-through basis, as required by the CPUC.

3 During 2010, SCE recorded a $39 million non-cash charge to reverse previously recognized federal tax benefits eliminated by the federal health care legislation enacted in March 2010. The health care law eliminated the federal tax deduction for retiree health care costs to the extent those costs are eligible for federal Medicare Part D subsidies.

The increase in income taxes for property-related items was primarily due to a cumulative deferred income tax adjustment of $30 million in 2011 related to nuclear fuel.

For a discussion of the status of Edison International's income tax audits, see "Edison International Notes to Consolidated Financial Statements—Note 7. Income Taxes."

LIQUIDITY AND CAPITAL RESOURCES

SCE's ability to operate its business, fund capital expenditures, and implement its business strategy are dependent upon its cash flow and access to the capital markets. SCE's overall cash flows fluctuate based on, among other things, its ability to recover its costs in a timely manner from its customers through regulated rates, changes in commodity prices and volumes, collateral requirements, interest and dividend payments to investors, and the outcome of tax and regulatory matters.

SCE expects to fund its 2012 obligations, capital expenditures and dividends through operating cash flows, tax benefits (including bonus depreciation) and capital market financings of debt and preferred equity, as needed. SCE also has availability under its credit facilities to meet operating and capital requirements.

In January and February 2012, SCE issued 250,000 shares and 100,000 shares, respectively, of 6.25% Series E preference

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stock (cumulative, $1,000 liquidation value). The Series E preference stock may not be redeemed prior to February 1, 2022. The proceeds from the sale of these shares were used to repay commercial paper borrowings issued to fund SCE's capital program.

Available Liquidity

SCE has two credit facilities: a $2.4 billion five-year credit facility that matures in February 2013 and a $500 million three-year credit facility that matures in March 2013.

(in millions)	Credit Facilities
Commitment	$2,894
Outstanding borrowings supported by credit facilities	(419)
Outstanding letters of credit	(81)
Amount available	$2,394

Debt Covenant

SCE has a debt covenant in its credit facilities that limits its debt to total capitalization ratio to less than or equal to 0.65 to 1. At December 31, 2011, SCE's debt to total capitalization ratio was 0.48 to 1.

Capital Investment Plan

SCE's forecasted capital expenditures for 2012 – 2014 include a capital forecast in the range of $11.8 billion to $13.2 billion based on the average variability experienced in 2011, 2010 and 2009 of 11% between annual forecast capital expenditures and actual spending. This capital forecast includes certain projects under CPUC jurisdiction that are subject to the outcome of the 2012 CPUC GRC. The completion of projects, the timing of expenditures, and the associated cost recovery may be affected by permitting requirements and delays, construction schedules, availability of labor, equipment and materials, financing, legal and regulatory approvals and developments, weather and other unforeseen conditions.

SCE's 2011 capital expenditures and the 2012 – 2014 capital expenditures forecast are set forth in the table below:

(in millions)	2011 Actual	2012	2013	2014	Total
Transmission	$929	$1,547	$1,452	$850	$3,849
Distribution	1,847	2,304	2,355	2,416	7,075
Generation	729	743	642	520	1,905
EdisonSmartConnect™	372	373	—	—	373
Total Estimated Capital Expenditures[1]	$3,877	$4,967	$4,449	$3,786	$13,202
Total Estimated Capital Expenditures for 2012 – 2014 (using 11% variability discussed above)		$4,421	$3,960	$3,369	$11,750

[1] Included in SCE's capital expenditures plan are projected environmental capital expenditures of $499 million, $534 million and $576 million in 2012, 2013 and 2014, respectively. The projected environmental capital expenditures are to comply with laws, regulations, and other nondiscretionary requirements.

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Transmission Projects

SCE has experienced cost increases on its Tehachapi and Devers-Colorado River Transmission Projects, primarily related to environmental monitoring and mitigation costs, scope changes and schedule delays. A summary of SCE's major transmission and substation projects during the next three years is presented below:

Project Name	Description	Project Lifecycle Phase	In Service Date	Direct Expenditures[1] (in millions)	% of Spend Complete	2012 – 2014 Forecast (in millions)
Tehachapi 1-11	Transmission lines and substation	In construction	2009 – 2015	$ 2,500	62 %	$ 904
Devers-Colorado River	Transmission line	In construction	2013	860	18 %	709
Eldorado-Ivanpah	Substation and upgraded transmission line	Engineering/Construction	2013	444	6 %	417
Red Bluff	Substation	In construction	2013	234	6 %	220

[1] Direct expenditures include direct labor, land and contract costs incurred for the respective projects and exclude overhead costs that are included in the capital expenditures forecasted for 2012 – 2014.

Currently, SCE is completing the final engineering design for the Tehachapi Transmission and the Devers-Colorado River Projects and has increased its 2012 – 2014 forecasted expenditures for these projects as a result of cost pressures discussed above. The Tehachapi Project costs and schedule may be further impacted by the CPUC's response to SCE's petition to modify the 2009 decision approving the project for the purpose of obtaining authorization to install aviation marking and lighting in accordance with FAA standards. In October 2011, the CPUC staff notified SCE that the constructed portions of the project should be marked and lighted as required, but instructed SCE to defer completion of remaining project components that may require aviation marking or lighting pending CPUC review of the petition to modify. Community opposition to portions of the project continues and requests for reconsideration of the CPUC's 2009 decision are pending. In January 2012, in response to a CPUC request, SCE provided information on potential new options for a portion of the project, including traversing a state park, changing the nature of some of the towers, and undergrounding lines. Adoption of any of these alternatives could create additional costs and delay the completion of the project. SCE is required to file revised cost estimates with the CPUC. As with all transmission investments, cost recovery will be subject to future rate proceedings.

Distribution Projects

Distribution expenditures include projects and programs to meet customer load growth requirements, reliability and infrastructure replacement needs, information and other technology and related facility requirements.

Generation Projects

Generation expenditures include:

- Nuclear-related capital expenditures necessary to maintain safe and reliable plant operation, meet NRC and other regulatory requirements, and optimize plant performance and cost-effectiveness.
- Hydro-related capital expenditures associated with infrastructure and equipment replacement and renewal of FERC operating licenses. Infrastructure expenditures include dam improvements, flowline and substation refurbishments, and powerline replacements. Equipment replacement expenditures include transformers, automation, switchgear, hydro turbine repowers, generator rewinds, and small generator replacements.
- SCE's Solar Photovoltaic Program to develop up to 125 MW of utility owned Solar Photovoltaic generating facilities generally ranging in size from 1 to 2 MW each, on commercial and industrial rooftops and other space in SCE's service territory. The CPUC has authorized recovery of reasonable costs and allowed for a return on investment.

EdisonSmartConnect™

SCE's EdisonSmartConnect™ project involves installing state-of-the-art "smart" meters in approximately 5 million households and small businesses through its service area. In March 2008, SCE was authorized by the CPUC to recover $1.63 billion in customer rates for the deployment phase of EdisonSmartConnect™. In 2009, SCE began full deployment of meters to all residential and small business customers under 200 kW. SCE anticipates completion of the deployment in 2012. In 2011, the CPUC began exploring the feasibility of allowing customers to voluntarily opt out of smart meter installation.

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SCE has provided information to the CPUC on the costs and technical issues involved. Should the CPUC order SCE to implement an opt out option, SCE would file an application seeking to recover the associated costs in rates.

Regulatory Proceedings

Energy Efficiency Shareholder Risk/Reward Incentive Mechanism

The CPUC previously adopted and extended through 2009 an Energy Efficiency Risk/Reward Incentive Mechanism ("Energy Efficiency Mechanism") allowing SCE to earn incentives based on SCE's performance toward meeting CPUC energy efficiency goals. In December 2011, the CPUC issued a decision approving an $18 million final payment for 2009 performance under the Energy Efficiency Mechanism. The CPUC is reviewing and may further modify or eliminate the Energy Efficiency Mechanism for performance periods subsequent to 2009.

San Onofre Outage and Repair Issues

Four replacement steam generators were installed at San Onofre Units 2 and 3 in 2010 and 2011. Inspections of the Unit 2 steam generators during a planned maintenance and refueling outage in February 2012 found some isolated areas of wear in some of the 19,454 heat transfer tubes. In light of this condition, SCE, in consultation with the steam generators' manufacturer, determined that a number of the tubes should be removed from service as a preventive measure. The steam generators are designed to include sufficient tubes to accommodate a need to remove some from service for a variety of reasons, including wear, and the tubes that SCE is in the process of preventively removing from service in Unit 2 are well within the extra margin. Additionally, on January 31, 2012, a water leak was detected in one of the tubes of a new steam generator in Unit 3, and the Unit was safely taken offline. Extensive testing of the Unit 3 steam generators is ongoing to fully understand the cause of the leak. In a memorandum dated February 16, 2012, the NRC determined that inasmuch as the leak was in a newly installed steam generator, it will conduct an event follow-up baseline inspection to review San Onofre's response to the leak and verify the appropriateness of its remedial actions. Each Unit will be restarted when repairs on that Unit are completed, and SCE is satisfied that it is safe to do so.

The steam generators were supplied by Mitsubishi Heavy Industries (“MHI”) and are warranted for an initial period of 20 years from acceptance. Subject to certain exceptions, the purchase agreement sets forth specified damages for certain repairs, generally limits MHI's aggregate contractual liability to the approximately $137 million purchase price of the generators and excludes consequential damages from recovery, such as the cost of replacement power. In 2005, the CPUC authorized expenditures of approximately $525 million ($665 million when adjusted for inflation) for SCE's 78.21% share of San Onofre to purchase and install new generators and remove their predecessors. Those expenditures remain subject to CPUC review upon submission of SCE's final costs for the overall project. SCE expects to file an application with the CPUC setting forth final project costs in the third or fourth quarter of 2012. Replacement power costs are recovered through the ERRA balancing account, subject to reasonableness review.

Dividend Restrictions

The CPUC regulates SCE's capital structure which limits the dividends it may pay Edison International. In SCE's most recent cost of capital proceeding, the CPUC set 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 48% authorized level on a 13-month weighted average basis. At December 31, 2011, SCE's 13-month weighted-average common equity component of total capitalization was 50.4% resulting in the capacity to pay $436 million in additional dividends.

During 2011, SCE made $461 million in dividend payments to its parent, Edison International. Future dividend amounts and timing of distributions are dependent upon several factors including the level of capital expenditures, operating cash flows and earnings.

Margin and Collateral Deposits

Certain derivative instruments, power procurement contracts and other contractual arrangements contain collateral requirements. Future collateral requirements may differ from the requirements at December 31, 2011, due to the addition of incremental power and energy procurement contracts with collateral requirements, if any, and the impact of changes in wholesale power and natural gas prices on SCE's contractual obligations.

Some of the power procurement contracts contain provisions that require SCE to maintain an investment grade credit rating from the major credit rating agencies. If SCE's credit rating were to fall below investment grade, SCE may be required to pay the liability or post additional collateral.

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The table below provides the amount of collateral posted by SCE to its counterparties as well as the potential collateral that would be required as of December 31, 2011.

(in millions)	
Collateral posted as of December 31, 2011[1]	$149
Incremental collateral requirements for power procurement contracts resulting from a potential downgrade of SCE's credit rating to below investment grade	89
Posted and potential collateral requirements[2]	$238

1 Collateral provided to counterparties and other brokers consisted of $51 million of cash which was offset against net derivative liabilities on the consolidated balance sheets, $17 million of cash reflected in "Other current assets" on the consolidated balance sheets and $81 million in letters of credit.

2 There would be no increase to SCE's total posted and potential collateral requirements based on SCE's forward positions as of December 31, 2011 due to adverse market price movements over the remaining lives of the existing power procurement contracts using a 95% confidence level.

Workers Compensation Self-Insurance Fund

SCE is self-insured for workers compensation claims. SCE assesses workers compensation claims that have been asserted and those that have been incurred but not reported to determine the probable amount of losses that should be recorded. The Department of Industrial Relations for the State of California requires companies that are self-insured for workers compensation to post collateral (in the form of cash and/or letters of credits) based on the estimated workers' compensation liability if a company's bond rating were to fall below "B." As of December 31, 2011, if SCE's bond rating were to fall below a "B" rating, SCE would be required to post $208 million for its workers compensation self-insurance plan.

Regulatory Balancing Accounts

SCE's cash flows are affected by regulatory balancing account over- or under-collections. Over- and under-collections represent differences between cash collected in current rates for specified forecasted costs and the costs actually incurred. With some exceptions, SCE seeks to adjust rates on an annual basis or at other designated times to recover or refund the balances recorded in its balancing account. Under- or over-collections in these balancing accounts impact cash flows and can change rapidly. Over- and under-collections accrue interest based on a three-month commercial paper rate published by the Federal Reserve.

As of December 31, 2011, balancing account net over-collections were $1.2 billion primarily related to public purpose-related program costs as well as fuel and power procurement-related costs. Over-collections for public purpose-related programs are expected to decrease as costs are incurred to fund programs established by the CPUC. The fuel and power procurement-related over-collections of $392 million are expected to be refunded through a rate adjustment in 2012.

Historical Segment Cash Flows

The table below sets forth condensed historical cash flow information for SCE:

(in millions)	2011	2010	2009
Net cash provided by operating activities	$3,261	$3,386	$4,069
Net cash provided (used) by financing activities	799	503	(1,999)
Net cash used by investing activities	(4,260)	(4,094)	(3,219)
Net decrease in cash and cash equivalents	$(200)	$(205)	$(1,149)

Net Cash Provided by Operating Activities

Net cash provided by operating activities decreased $125 million in 2011 compared to 2010. The decrease in cash flows provided by operating activities was primarily due to the following:

- $310 million decrease from refunding to customers overcollections of revenue which resulted from actual electricity sales exceeding forecasted electricity sales. SCE began refunding this balance through a rate adjustment effective June 1, 2011;
- $250 million decrease resulting from higher balancing account overcollections for fuel and power procurement-related

costs in 2010 when compared to 2011 (overcollections of approximately $300 million in 2010 compared to approximately $50 million in 2011). The 2010 overcollection was primarily due to lower realized gas and power prices compared to the amounts forecasted for setting customer rates. SCE began refunding the overcollection through a rate adjustment beginning on June 1, 2011. The balancing account was over-collected by $392 million at December 31, 2011, $345 million at December 31, 2010, $46 million at December 31, 2009 and under-collected by $406 million at December 31, 2008; and

- $365 million increase resulting from higher income before depreciation and income taxes primarily driven by higher customer revenue.

Net cash provided by operating activities decreased $683 million in 2010, compared to 2009. The cash flows provided by operating activities were primarily due to the following:

- $531 million decrease in cash reflecting lower net tax receipts in 2010 compared to 2009 primarily related to the impacts of the Global Settlement. In 2009, SCE received tax-allocation payments of $875 million from the Global Settlement, compared to tax-allocation payments received of $26 million in 2010. This decrease was partially offset by higher estimated tax payments in 2009 compared to 2010.
- $155 million net cash inflow from balancing accounts composed of:
- $310 million net cash inflow from the funding of public purpose and solar initiative programs and lower pension and PBOP contributions in 2010 compared to 2009; and
- $155 million net cash outflow due to the decrease in balancing account cash flows for fuel and power procurement-related costs (collections of approximately $300 million in 2010, compared to collections of approximately $450 million in 2009).
- Timing of cash receipts and disbursements related to working capital items, including a net cash outflow of $95 million related to the timing of fuel and power procurement-related activities primarily related to ISO charges and a $60 million decrease in margin and collateral deposits – net of collateral received.

Net Cash Provided (Used) by Financing Activities

Cash provided (used) by financing activities mainly consisted of net repayments of short-term debt and long-term debt issuances (payments).

Net cash provided by financing activities for 2011 was $799 million consisting of the following significant events:

- Issued $500 million of 3.875% first and refunding mortgage bonds due in 2021. The proceeds from these bonds were used to repay commercial paper borrowings and to fund SCE's capital program.
- Issued a net $419 million of commercial paper supported by SCE's line of credit to fund interim working capital requirements.
- Issued $250 million of 3.9% first and refunding mortgage bonds due in 2041. The proceeds from these bonds were used to fund SCE's capital program.
- Issued $150 million of floating rate first and refunding mortgage bonds due in 2014. The proceeds from these bonds were used to finance fuel inventories.
- Issued $125 million of 6.5% Series D preference stock. The proceeds from the issuance were used to fund SCE's capital program.
- Paid $461 million of dividends to Edison International.
- Purchased $86 million of SCE variable rate tax-exempt bonds.

Net cash provided by financing activities for 2010 was $503 million consisting of the following significant events:

- Issued $1 billion of first refunding mortgage bonds due in 2040 to fund SCE's capital program.
- Reissued $144 million of tax-exempt pollution control bonds due in 2035 to fund SCE's capital program.
- Repaid $250 million of senior unsecured notes.

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- Paid $300 million in dividends to Edison International.

Net cash used by financing activities for 2009 was $2.0 billion consisting of the following significant events:

- Issued $500 million of first refunding mortgage bonds due in 2039 and $250 million of first and refunding mortgage bonds due in 2014. The bond proceeds were used for general corporate purposes and to finance fuel inventories, respectively.
- Repaid a net $1.9 billion of short-term debt.
- Repaid $150 million of first and refunding mortgage bonds.
- Purchased $219 million of two issues of tax-exempt pollution control bonds and converted the issues to a variable rate structure. As discussed above, SCE reissued $144 million of these bonds in 2010. SCE continues to hold the remaining $75 million of these bonds which are outstanding and have not been retired or cancelled.
- Paid $300 million in dividends to Edison International.

Net Cash Used by Investing Activities

Cash flows from investing activities are primarily due to capital expenditures and funding of nuclear decommissioning trusts. Capital expenditures were $4.1 billion, $3.8 billion and $3.0 billion for 2011, 2010 and 2009, respectively, primarily related to transmission, distribution and generation investments. Net purchases of nuclear decommissioning trust investments and other were $167 million, $219 million and $199 million for 2011, 2010 and 2009, respectively.

Contractual Obligations and Contingencies

Contractual Obligations

SCE's contractual obligations as of December 31, 2011, for the years 2012 through 2016 and thereafter are estimated below.

(in millions)	Total	Less than 1 year	1 to 3 years	3 to 5 years	More than 5 years
Long-term debt maturities and interest[1]	$16,422	$434	$2,028	$1,411	$12,549
Power purchase agreements[2]:					
Renewable energy contracts	16,578	561	1,328	1,503	13,186
Qualifying facility contracts	3,677	439	875	794	1,569
Other power purchase agreements	6,298	624	1,640	1,181	2,853
Other operating lease obligations[3]	641	73	135	109	324
Purchase obligations[4]:					
Nuclear fuel supply contract payments	1,068	190	213	206	459
Other fuel supply contract payments	268	42	97	129	—
Other contractual obligations[5]	323	21	51	39	212
Employee benefit plans contributions[6]	1,528	325	635	568	—
Total[7,8]	$46,803	$2,709	$7,002	$5,940	$31,152

1 For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 5. Debt and Credit Agreements." Amount includes interest payments totaling $8.0 billion over applicable period of the debt.

2 Certain power purchase agreements entered into with independent power producers are treated as operating or capital leases. At December 31, 2011, minimum operating lease payments for power purchase agreements were $839 million in 2012, $966 million in 2013, $930 million in 2014, $916 million in 2015, $815 million in 2016, and $11.5 billion for the thereafter period. At December 31, 2011, minimum capital lease payments for power purchase agreements were $33 million in 2012, $33 million 2013, $72 million for 2014, $109 million for 2015, $109 million for 2016, and $1.8 billion for the thereafter period (amounts include executory costs and interest of $445 million and $773 million, respectively). For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies."

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3 At December 31, 2011, minimum other operating lease payments were primarily related to vehicles, office space and other equipment. For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies."

4 For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies."

5 At December 31, 2011, other commitments were primarily related to maintaining reliability and expanding SCE's transmission and distribution system.

6 Amount includes estimated contributions to the pension and PBOP plans. The estimated contributions for SCE are not available beyond 2016. These amounts represent estimates that are based on assumptions that are subject to change. In addition, funding of future contributions could be impacted by the final 2012 GRC decision. See "Item 8. Edison International Notes to Consolidated Financial Statements—Note 8. Compensation and Benefit Plans" for further information.

7 At December 31, 2011, SCE had a total net liability recorded for uncertain tax positions of $258 million, which is excluded from the table. SCE 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.

8 The contractual obligations table does not include derivative obligations and asset retirement obligations, which are discussed in "Item 8. Edison International Notes to Consolidated Financial Statements—Note 6. Derivative Instruments and Hedging Activities," and "Item 8. Edison International Notes to Consolidated Financial Statements—Note 2. Property, Plant and Equipment," respectively.

Contingencies

SCE has contingencies related to the CPSD Investigations, Four Corners New Source Review litigation, nuclear insurance, wildfire insurance and spent nuclear fuel, which are discussed in "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies."

Environmental Remediation

SCE 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. SCE 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, SCE records the lower end of this reasonably likely range of costs (classified as "Other long-term liabilities") at undiscounted amounts as timing of cash flows is uncertain.

As of December 31, 2011, SCE had identified 24 material sites for remediation and recorded an estimated minimum liability of $49 million. SCE expects to recover 90% of its remediation costs at certain sites. See "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies" for further discussion.

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. Derivative instruments are used, as appropriate, to manage market risks for customers and SCE. For a further discussion of SCE's market risk exposures, including commodity price risk, credit risk and interest rate risk, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 6. Derivative Instruments and Hedging Activities" and "—Note 4. Fair Value Measurements."

Interest Rate Risk

SCE is exposed to changes in interest rates primarily as a result of its financing and short-term investing activities used for liquidity purposes, to fund business operations and to fund capital investments. 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. Changes in interest rates may impact SCE's authorized rate of return for the period beyond 2012, see "Item 1. Business—Overview of Ratemaking Process—CPUC" for further discussion.

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At December 31, 2011, the fair market value of SCE's long-term debt (including current portion of long-term debt) was $10.1 billion, compared to a carrying value of $8.4 billion. A 10% increase in market interest rates would have resulted in a $399 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 $430 million increase in the fair market value of SCE's long-term debt.

Commodity Price Risk

SCE and its customers are exposed to the risk of a change in the market price of natural gas and electric power. SCE's hedging program reduces exposure to variability in market prices related to SCE's purchases and sales of electric power and natural gas. SCE expects recovery of its related hedging costs through the ERRA balancing account or CPUC-approved procurement plans, and as a result, exposure to commodity price is not expected to impact earnings, but may impact the timing of cash flows. SCE's hedging program reduces customer exposure to variability in market prices. As part of this program, SCE enters into energy options, swaps, forward arrangements, tolling arrangements, and congestion revenue rights ("CRRs"). The transactions are pre-approved by the CPUC or executed in compliance with CPUC-approved procurement plans. For further discussion on derivative instruments entered into to mitigate commodity price exposures, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 6. Derivative Instruments and Hedging Activities."

Fair Value of Derivative Instruments

With some exceptions, SCE records derivative instruments on its consolidated balance sheets at fair value. Changes in the fair value of derivative instruments are expected to be recovered from or refunded to customers through regulatory mechanisms and, therefore, SCE's fair value changes have no impact on earnings. SCE does not use hedge accounting for these transactions due to this regulatory accounting treatment. For further discussion on fair value measurements and the fair value hierarchy, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 4. Fair Value Measurements."

The fair value of outstanding derivative instruments used at SCE to mitigate its exposure to commodity price risk was a net liability of $936 million and $207 million at December 31, 2011 and 2010, respectively. The increase in the net liability was related to changes in unrealized losses on economic hedging activities primarily due to declining power and natural gas prices. The following table summarizes the increase or decrease to the fair values of outstanding derivative instruments as of December 31, 2011, if the electricity prices or gas prices were changed while leaving all other assumptions constant:

(in millions)	December 31, 2011
Increase in electricity prices by 10%	$266
Decrease in electricity prices by 10%	(581)
Increase in gas prices by 10%	(340)
Decrease in gas prices by 10%	(7)

Credit Risk

For information related to credit risks and how SCE manages credit risk, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 6. Derivative Instruments and Hedging Activities."

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 (derivative assets less derivative liabilities) reflected on the consolidated balance sheets. 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. SCE manages the credit risk on the portfolio for both rated and non-rated 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.

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As of December 31, 2011, the amount of balance sheet exposure as described above broken down by the credit ratings of SCE's counterparties, was as follows:

	December 31, 2011		
(in millions)	Exposure[2]	Collateral	Net Exposure
S&P Credit Rating[1]			
A or higher	$122	$—	$122
Not rated[3]	11	(3)	8
Total	$133	$(3)	$130

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 purchases and sales and non-derivative contractual commitments that are not recorded on the consolidated balance sheets, except for any related net accounts receivable.

3 The exposure in this category relates to long-term power purchase agreements. SCE's exposure is mitigated by regulatory treatment.

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EDISON MISSION GROUP
RESULTS OF OPERATIONS
Results of Continuing Operations

EMG primarily operates in one line of business, independent power production. The following table is a summary of competitive power generation results of operations for the periods indicated.

	For The Years ended December 31,		
(in millions)	2011	2010	2009
Competitive power generation operating revenues	$2,186	$2,429	$2,399
Fuel	799	809	796
Operation and maintenance	1,069	1,020	964
Depreciation and amortization	310	249	239
Asset impairments, lease terminations and other	1,772	48	891
Total operating expenses	3,950	2,126	2,890
Operating income (loss)	(1,764)	303	(491)
Interest and dividend income	32	30	30
Equity in income from unconsolidated affiliates – net	86	106	89
Other income	19	8	12
Interest expense	(324)	(264)	(306)
Other expenses	—	—	(9)
Income (loss) from continuing operations before income taxes	(1,951)	183	(675)
Income tax benefit	(864)	(36)	(284)
Income (loss) from continuing operations	(1,087)	219	(391)
Income (loss) from discontinued operations–net of tax	(3)	4	(7)
Net income (loss)	(1,090)	223	(398)
Less: Net loss attributable to noncontrolling interests	(1)	(1)	(3)
Net income (loss) available for common stock	$(1,089)	$224	$(395)
Core Earnings (Losses)[1]	$(25)	$192	$222
Non-Core Earnings (Losses):			
Global Settlement[2]	—	52	(610)
Asset impairments and other charges	(1,050)	(24)	—
Gain on sale of March Point	5	—	—
Write down of net investment in aircraft leases	(16)	—	—
Discontinued Operations	(3)	4	(7)
Total EMG GAAP Earnings (Losses)	$(1,089)	$224	$(395)

[1] See use of Non-GAAP financial measures in "Edison International Overview—Highlights of Operating Results."

[2] Includes termination of Edison Capital's cross-border leases and state tax impacts of Global Settlement with the IRS.

EMG had a core loss in 2011 compared to core earnings in 2010 primarily due to the following pre-tax items:

- $206 million and $122 million decreases in Midwest Generation and Homer City income, respectively, primarily due to lower average realized energy and capacity prices and generation.
- $60 million increase in interest expense due to new energy project financings ($33 million) and lower capitalized interest ($27 million).
- $36 million decrease in energy trading due to reduced revenues from trading power contracts and the allocation to Homer City of benefits from an arrangement that allows EMMT to deliver a portion of Homer City's power into the

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NYISO (such decrease resulting from that allocation is offset by revenues recognized at Homer City).

- $18 million increase in renewable energy income due to the increase in wind projects in operation coupled with higher generation due to more favorable wind conditions, partially offset by lower realized energy prices at the merchant wind projects.

Consolidated non-core items for 2011 and 2010 included:

- An after-tax earnings charge of $1.09 billion ($1.76 billion pre-tax) recorded in the fourth quarter of 2011 resulting primarily from the impairment the Homer City, Fisk, Crawford and Waukegan power plants, wind related charges, write-down of a net investment in aircraft leases with American Airlines, and the impact on Edison International consolidated deferred income taxes resulting from an increase in the state apportionment rates due to such impairment charges as discussed in "Edison International Overview—Management Overview of EMG" and "Item 8. Edison International Notes to Consolidated Financial Statements Note 16—Asset Impairments, Lease Terminations and Other."
- An earnings benefit of $52 million in 2010 related to the acceptance by the California Franchise Tax Board of the tax positions finalized with the Internal Revenue Service in 2009 for the tax years 1986 through 2002 as part of the federal settlement of tax disputes and a revision to interest on federal disputed tax items. For more information, see "—Income Taxes" below.
- An after-tax earnings charge of $24 million ($40 million pre-tax) recorded in the fourth quarter of 2010 resulting from the write-off of capitalized engineering and other costs related to a change in air emissions control technology selection at the Powerton Station.

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Adjusted Operating Income (Loss) ("AOI")—Overview

The following table shows the adjusted operating income (loss) (AOI) of EMG's projects:

	Years ended December 31,		
(in millions)	2011	2010	2009
Midwest Generation plants	$(542)	$264	$340
Homer City plant[1]	(1,040)	114	186
Renewable energy projects	39	51	53
Energy trading[1]	74	110	49
Big 4 projects	44	52	46
Sunrise	32	33	37
Doga	26	15	8
March Point	8	17	11
Westside projects	7	1	4
Leveraged lease income	5	5	14
Lease terminations and other	(22)	(3)	(887)
Other projects	10	10	3
Other operating income (expense)[2]	(36)	1	(2)
	(1,395)	670	(138)
Corporate administrative and general	(142)	(150)	(175)
Corporate depreciation and amortization	(24)	(19)	(15)
AOI[3]	$(1,561)	$501	$(328)

1 Effective April 1, 2011, EMMT allocated to Homer City the benefit of an arrangement that allows EMMT to deliver a portion of Homer City's power into the NYISO. To the extent this arrangement is not utilized, Homer City's power is delivered into PJM.

2 Primarily related to EMG's decision to reduce its development pipeline and ongoing development activities. For additional information, see "Edison International (Consolidated): Liquidity and Capital Resources—Critical Accounting Estimates and Policies—Impairment of Long Lived Assets—Application to Selected EMG Wind Projects" in the MD&A and "Item 8. Edison International Notes to Consolidated Financial Statements—Note 16. Asset Impairments, Lease Terminations and Other."

3 AOI is equal to operating income (loss) under GAAP, plus equity in income (loss) of unconsolidated affiliates, dividend income from projects, production tax credits, other income and expenses, and net loss attributable to noncontrolling interests. Production tax credits are recognized as wind energy is generated based on a per-kilowatt-hour rate prescribed in applicable federal and state statutes. AOI 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, other income and expenses, and net loss attributable to noncontrolling interests in AOI is meaningful for investors as these components are integral to the operating results of EMG.

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The following table reconciles AOI to operating income (loss) as reflected on EMG's consolidated statements of operations:

	Years ended December 31,		
(in millions)	2011	2010	2009
AOI	$(1,561)	$501	$(328)
Less:			
Equity in income of unconsolidated affiliates	86	106	89
Dividend income from projects	31	21	12
Production tax credits	66	62	56
Other income, net	19	8	3
Net loss attributable to noncontrolling interests	1	1	3
Operating Income (Loss)	$(1,764)	$303	$(491)

Adjusted Operating Income from Consolidated Operations

Midwest Generation Plants

The following table presents additional data for the Midwest Generation plants:

	Years ended December 31		
(in millions)	2011	2010	2009
Operating Revenues	$1,286	$1,479	$1,487
Operating Expenses			
Fuel[1]	512	519	547
Plant operations	456	448	396
Plant operating leases	75	75	75
Depreciation and amortization	117	114	109
Asset impairments and other charges	650	42	2
Administrative and general	22	22	21
Total operating expenses	1,832	1,220	1,150
Operating Income (Loss)	(546)	259	337
Other Income	4	5	3
AOI	$(542)	$264	$340
Statistics			
Generation (in GWh)			
Energy contracts	28,145	29,798	28,977
Load requirements services contracts	—	—	1,333
Total	28,145	29,798	30,310

1 Included in fuel costs were $3 million, $13 million and $63 million in 2011, 2010 and 2009, respectively, related to the net cost of emission allowances.

AOI from the Midwest Generation plants decreased $806 million in 2011 compared to 2010, and decreased $76 million in 2010 compared to 2009. The 2011 decrease in AOI, excluding the $640 million impairment charge previously discussed in "Edison International Overview—Highlights of Operating Results," was primarily attributable to lower energy and capacity revenues. The decline in energy revenues was due to lower average realized energy prices and lower generation due to the permanent shutdown of Will County Units 1 and 2 at the end of 2010 in accordance with the CPS. The decline in capacity revenues was due to lower capacity prices from the RPM auction. In addition, the change in AOI was impacted by a $40 million pre-tax charge in 2010 related to the write-off of capitalized engineering and other costs related to a change in air emissions control technology at the Powerton Station and a $24 million gain from the sale of bankruptcy claims against Lehman. The claims originated from power contracts that were terminated in 2008 due to the bankruptcy of Lehman.

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The 2010 decrease in AOI from 2009 was primarily attributable to unrealized losses in 2010 compared to unrealized gains in 2009 related to hedge contracts and an increase in plant maintenance costs, partially offset by higher capacity revenues and lower average realized fuel costs. Plant maintenance and overhaul related expenses were higher in 2010 due to the deferral of plant outages in 2009. Average realized fuel costs per megawatt-hour were lower in 2010 as compared to 2009 primarily due to lower emission allowance costs partially offset by higher costs for activated carbon, which is used to reduce mercury emissions. The write-off of capitalized costs at the Powerton Station and the gain from the sale of bankruptcy claims against Lehman also affected the comparison of results between these periods.

Included in operating revenues were unrealized gains (losses) of $3 million, $(6) million and $30 million in 2011, 2010 and 2009, respectively. Unrealized gains (losses) were primarily attributable to economic hedge contracts that are accounted for at fair value with offsetting changes recorded on the consolidated statements of operations. In addition, $10 million and $14 million was reversed from accumulated other comprehensive income and recognized in 2010 and 2009, respectively, related to power contracts with Lehman that were dedesignated as cash flow hedges, subsequently terminated and recorded as unrealized losses in 2008. Unrealized gains (losses) also included the ineffective portion of hedge contracts at the Midwest Generation plants attributable to changes in the difference between energy prices at the Northern Illinois Hub (the settlement point under forward contracts) and the energy prices at the Midwest Generation plants' busbars (the delivery point where power generated by the Midwest Generation plants is delivered into the transmission system) resulting from marginal losses.

Included in fuel costs were unrealized gains (losses) of $(4) million, $(7) million and $15 million in 2011, 2010 and 2009, respectively, due to oil futures contracts that were accounted for as economic hedges. These contracts were entered into in 2010 and 2009 to hedge variable fuel oil components of rail transportation costs.

Homer City

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

	Years ended December 31,		
(in millions)	2011	2010	2009
Operating Revenues[1]	$527	$636	$663
Operating Expenses			
Fuel[2]	269	279	251
Plant operations	137	116	103
Plant operating leases	102	103	102
Depreciation and amortization	21	18	16
Asset impairments and other charges	1,032	1	1
Administrative and general	6	5	4
Total operating expenses	1,567	522	477
Operating Income (Loss)	(1,040)	114	186
AOI	$(1,040)	$114	$186
Statistics			
Generation (in GWh)	9,428	11,028	11,446

1 Effective April 1, 2011, EMMT allocated to Homer City the benefit of an arrangement that allows EMMT to deliver a portion of Homer City's power into the NYISO. To the extent this arrangement is not utilized, Homer City's power is delivered into PJM.

2 Included in fuel costs were $9 million, $7 million and $16 million in 2011, 2010 and 2009, respectively, related to the net cost of emission allowances.

AOI from the Homer City plant decreased $1.2 billion in 2011 compared to 2010 and decreased $72 million in 2010 compared to 2009. The 2011 decrease in AOI, excluding the $1.03 billion impairment charge previously discussed in "Edison International Overview—Highlights of Operating Results," was primarily attributable to lower energy revenues, driven by lower generation and average realized energy prices, lower capacity revenues, and higher plant maintenance costs from outages at Units 1 and 2, partially offset by unrealized gains in 2011 compared to unrealized losses in 2010 related to hedge contracts and lower fuel costs. The decline in fuel costs was primarily due to lower generation, mostly offset by higher coal costs. Coal costs increased due to higher coal prices. The Homer City plant continued to have a high forced outage rate during 2011 partially as a result of the steam pipe rupture on Unit 1 and the related precautionary maintenance on Unit 2.

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The 2010 decrease in AOI from 2009 was primarily attributable to unrealized losses in 2010 compared to unrealized gains in 2009 related to hedge contracts, higher coal costs, lower generation, and higher plant operations costs related to scheduled plant outages, partially offset by an increase in capacity revenues. The Homer City plant experienced increased forced outages in 2010 compared to 2009 due to deratings to comply with opacity restrictions and unscheduled outages. Plant maintenance and overhaul related expenses were higher in 2010 due to the deferral of plant outages in 2009. Coal costs increased due to higher coal prices and changes in the mix of ready-to-burn coal and raw coal consumed.

Included in operating revenues were unrealized gains (losses) from hedge activities of $5 million, $(20) million and $15 million in 2011, 2010 and 2009, respectively. Unrealized gains (losses) were primarily attributable to the ineffective portion of hedge contracts at the Homer City plant attributable to changes in the difference between energy prices at the 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 plant is delivered into the transmission system). For additional discussion, see "Edison International Overview—Management Overview of EMG—Homer City Lease."

Renewable Energy Projects

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

	Years ended December 31,		
(in millions)	2011	2010	2009
Operating Revenues	$221	$137	$141
Production Tax Credits	66	62	56
	287	199	197
Operating Expenses			
Plant operations	78	55	55
Depreciation and amortization	141	89	92
Asset impairments and other charges	30	3	—
Administrative and general	4	3	3
Total operating expenses	253	150	150
Equity in income from unconsolidated affiliates	1	—	—
Other Income	3	2	3
Net Loss Attributable to Noncontrolling Interests	1	—	3
AOI[1]	$39	$51	$53
Statistics			
Generation (in GWh)[2]	5,564	3,646	3,081

1 AOI is equal to operating income (loss) under GAAP plus equity in income (loss) of unconsolidated affiliates, dividend income from projects, production tax credits, other income and expense, and net (income) loss attributable to noncontrolling interests. 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, AOI 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 AOI for wind projects is meaningful for investors as federal and state subsidies are an integral part of the economics of these projects.

2 Includes renewable energy projects that are unconsolidated at EMG. Generation excluding unconsolidated projects was 4,816 GWh in 2011, 3,037 GWh in 2010 and 2,514 GWh in 2009.

AOI from renewable energy projects, excluding the $30 million impairment charge previously discussed in "Edison International Overview—Highlights of Operating Results," increased $18 million in 2011, and decreased $2 million in 2010 compared to 2009. The 2011 increase was primarily attributable to projects that achieved commercial operation in late 2010 and 2011 and increased generation at other projects due to favorable wind conditions during 2011, partially offset by lower realized prices from the merchant wind projects. EMG's share of installed capacity of new wind projects that commenced operations during 2011, 2010 and 2009 was 295 MW, 150 MW and 223 MW, respectively.

AOI in 2010 and 2009 included payments from Suzlon Wind Energy Corporation (Suzlon) for availability losses of

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$2 million and $17 million, respectively. Payments under the availability guarantee are designed to compensate EMG for lost earnings, including production tax credits. Accordingly, the payments under the availability guarantee are paid on a pre-tax basis which affects period-to-period comparisons that include production tax credits which are after tax.

Energy Trading

AOI from energy trading activities decreased $36 million in 2011 compared to 2010, and increased $61 million in 2010 compared to 2009. The 2011 decrease was partially due to reduced revenues from power trading contracts in 2011 compared to 2010, partially offset by increased congestion revenues due to outages in the PJM markets. The decrease is also partially due to the allocation to Homer City of the benefit of an arrangement that allows EMMT to deliver a portion of Homer City's power into the NYISO. The 2010 increase in AOI energy trading activities was attributable to increased revenues in congestion and power trading. Congestion trading results increased in 2010 compared to 2009 due to unseasonably cold weather and transmission outages in the New York and PJM markets.

Adjusted Operating Income from Leveraged Lease Activities and Lease Terminations and Other

AOI from leveraged lease income declined from 2009 as a result of the termination of cross border leases which resulted in a $920 million loss. This loss was partially offset by a $33 million gain in 2009 from the sale of an interest in a leveraged lease (Midlands Cogeneration Ventures). For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 16. Asset Impairments, Lease Terminations and Other."

Adjusted Operating Income from Other Projects

The CPUC-approved comprehensive settlement related to power sales from cogeneration facilities became effective in November 2011, and resulted in additional non-recurring adjusted operating income in 2011 totaling $11 million.

Big 4 Projects. AOI from the Big 4 projects decreased $8 million in 2011 compared to 2010, and increased $6 million in 2010 compared to 2009. The 2011 decrease was primarily due to lower energy margins at Watson and lower contracted capacity under Midway-Sunset's new power purchase agreement, partially offset by additional revenues due to the settlement agreement discussed above. The 2010 increase was driven by changes in natural gas prices affecting steam revenues and plant maintenance.

Westside Projects. AOI from the Westside projects increased $6 million in 2011 compared to 2010, and decreased $3 million in 2010 compared to 2009. The 2011 increase was primarily attributable to the new power purchase agreements, which became effective upon the settlement discussed above, and provided higher capacity prices retroactive to 2010. The 2010 decrease was primarily due to higher fuel and maintenance costs partially offset by higher revenues.

Doga. The 2011 increase in AOI was due to higher distributions resulting primarily from the elimination of restricted cash as a result of the repayment of the remaining project debt. The 2010 increase was due to the timing of distributions. AOI is recognized when cash is distributed from the project as the Doga project is accounted for on the cost method.

March Point. The 2011 income was due to the receipt of payment from the sale of the project. The 2010 AOI was primarily due to equity distributions received from the project prior to the sale of EMG ownership interest to its partner.

Corporate Administrative and General Expenses

Corporate administrative and general expenses were lower during the past two years as EMG reduced development costs incurred pursuing renewable projects.

Interest Income (Expense)

	Years ended December 31,		
(in millions)	2011	2010	2009
Interest income	$1	$9	$17
Interest expense, net of capitalized interest			
EME debt	(257)	(229)	(267)
Non-recourse debt	(67)	(35)	(39)
	$(324)	$(264)	$(306)

Interest income decreased primarily due to lower interest rates and, to a lesser extent, lower average cash balances.

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EMG's interest expense increased $60 million in 2011 from 2010 and decreased $42 million in 2010 from 2009. The 2011 increase in interest expense was primarily due to higher debt balances from new project financings and lower capitalized interest. The 2010 decrease in interest expense was primarily due to higher capitalized interest and lower debt balances under EME's and Midwest Generation's credit facilities, partially offset by higher wind project financing. Capitalized interest was $27 million, $54 million and $19 million in 2011, 2010 and 2009, respectively. The 2011 decrease was due to completion of the renewable energy projects under construction in 2010 and 2011. The 2010 increase was the result of increased interest capitalization for renewable energy projects under construction.

Income Taxes

The table below provides a reconciliation of income tax expense computed at the federal statutory income tax rate:

	Years ended December 31,					
(in millions)	2011		2010		2009	
Income (loss) from continuing operations before income taxes	$(1,951	)	$183		$(675	)
Provision for income tax expense (benefit) at federal statutory rate of 35%	$(683	)	$64		$(236	)
Increase (decrease) in income tax from:						
Global settlement related	—		(52	)	37	
State tax – net of federal provision (benefit)	(104	)	3		(20	)
Tax credits, net	(68	)	(66	)	(63	)
Property-related	(6	)	15		(2	)
Other	(3	)	—		—	
Total income tax benefit from continuing operations	$(864	)	$(36	)	$(284	)
Effective tax rate	44	%	*		42	%

* Not meaningful.

EMG's effective tax rate for 2011 was impacted by production tax credits and estimated state income tax benefits allocated from Edison International. The effective tax rate for 2010 was impacted by production tax credits and the Global Settlement. Estimated state income tax benefits allocated from Edison International of $6 million, $7 million and $15 million were recognized for the years ended December 31, 2011, 2010 and 2009, respectively.

For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 7. Income Taxes."

Results of Discontinued Operations

The results of discontinued operations include foreign exchange gains and interest expense on contract indemnities denominated in euros, adjustments to unrecognized tax benefits, and expiration in 2010 of another contract indemnity. The contract indemnities relate to the sale of EMG's international projects in December 2004.

Related Party Transactions

EMG owns interests in partnerships that sell electricity generated by their project facilities to SCE and others under the terms of power purchase agreements. Sales by these partnerships to SCE under these agreements amounted to $277 million, $367 million and $366 million in 2011, 2010 and 2009, respectively.

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LIQUIDITY AND CAPITAL RESOURCES

Available Liquidity

The following table summarizes available liquidity at December 31, 2011:

(in millions)	Cash and Cash Equivalents	Available Under Credit Facilities[1]	Total Available Liquidity
EME as a holding company	$738	$498	$1,236
EME subsidiaries without contractual dividend restrictions	213	—	213
EME corporate cash and cash equivalents	951	498	1,449
EME subsidiaries with contractual dividend restrictions			
Midwest Generation[2]	213	497	710
Homer City	84	—	84
Other EME subsidiaries	52	—	52
Other EMG subsidiaries	61	—	61
Total	$1,361	$995	$2,356

1 Existing credit facilities mature in 2012. For further discussion, see "Edison International Overview—Management Overview of EMG" in the MD&A and "Item 1A. Risk Factors—Risks Relating to EMG—Liquidity Risks." The EME credit facility was terminated subsequent to year end.

2 Cash and cash equivalents are available to meet Midwest Generation's operating and capital expenditure requirements.

EME, as a holding company, does not directly operate any revenue-producing generation facilities, EME relies on cash distributions and tax payments from its projects and tax benefits received under a tax-allocation agreement with Edison International to meet its obligations, including debt service obligations on long-term debt. The timing and amount of distributions from EME's subsidiaries may be restricted. For further details, including the current restrictions on distributions from the Homer City facility, see "—Debt Covenants and Dividend Restrictions—Dividend Restrictions in Major Financings."

The following table summarizes the status of the EME and Midwest Generation credit facilities, which mature in June 2012, at December 31, 2011:

(in millions)	EME	Midwest Generation
Commitments	$564	$500
Outstanding borrowings	—	—
Outstanding letters of credit	(66)	(3)
Amount available	$498	$497

Senior notes in the principal amount of $500 million, which bear interest at 7.50% per annum, are due in June 2013. EME may from time to time, seek to retire or purchase its outstanding debt through cash purchases and/or exchange offers, open market purchases, privately negotiated transactions or otherwise, depending on prevailing market conditions, EME's liquidity requirements, contractual restrictions and other factors.

For information regarding EMG's plan to obtain third-party capital to finance the development of a portion of EMG's wind portfolio, see "Edison International Overview—Management Overview of EMG—EMG's Renewable Energy Activities" in the MD&A and "Item 8. Edison International Notes to Consolidated Financial Statements—Note 3. Variable Interest Entities—Categories of VIEs—Capistrano Wind Equity Capital-2012."

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Capital Investment Plan

Forecasted capital expenditures through 2014 by EMG's subsidiaries for existing projects and corporate activities are as follows:

(in millions)	2012	2013	2014
Midwest Generation Plants			
Environmental[1]	$35	$102	311
Plant Capital	21	46	16
Walnut Creek Project	229	40	—
Renewable Energy Projects			
Capital and construction	114	1	2
Other capital	22	19	15
Total	$421	$208	344

1 For additional information, see "Edison International Overview—Management Overview of EMG—Midwest Generation Environmental Compliance Plans and Costs."

Midwest Generation Capital Expenditures

Midwest Generation plants' projected environmental expenditures would retrofit Powerton Units 5 and 6, Joliet Units 7 and 8 and Will County Units 3 and 4, using dry scrubbing with sodium-based sorbents and upgrading particulate removal systems to comply with CPS requirements for SO_2 emissions and the US EPA's regulation on HAP emissions. Decisions regarding whether or not to proceed with retrofitting any particular remaining units to comply with CPS requirements for SO_2 emissions, including those that have received permits, remain subject to a number of factors, such as market conditions, regulatory and legislative developments, and forecasted commodity prices and capital and operating costs applicable at the time decisions are required or made. Final decisions on whether to install controls, to install particular kinds of controls, and to actually expend capital or continue with the expenditure of capital will be made as required, subject to the requirements of the CPS and other applicable regulations. Furthermore, the timing of commencing capital projects may vary from the amounts set forth in the above table. For additional discussion, see "Edison International Overview—Management Overview of EMG—Midwest Generation Environmental Compliance Plans and Costs."

Plant capital expenditures for Midwest Generation includes capital projects for boiler and turbine controls, major boiler components and electrical systems.

Homer City Capital Expenditures

The capital investment plan set forth above does not include environmental capital expenditures to retrofit the Homer City plant because Homer City does not have the funds for retrofits and has not yet been able to raise capital needed for such retrofits. The funding of Homer City's environmental expenditures will be dependent on external funding. See "Edison International Overview—Management Overview of EMG—Homer City Lease." Plant capital expenditures for Homer City are projected to be $39 million, $23 million, and $14 million in 2012, 2013, and 2014, respectively.

Walnut Creek Capital Expenditures

In July 2011, EME secured $495 million in construction and term financing for the Walnut Creek project.

Renewable Energy Projects

Construction of the 80 MW Broken Bow I wind project commenced during the third quarter of 2011 and EME expects the 40 MW Crofton Bluffs wind project to commence construction in the second quarter of 2012. Commercial operations of the Broken Bow I and the Crofton Bluffs projects are expected in the fourth quarter of 2012.

On December 21, 2011, EMG closed a $242 million financing for a portfolio of three contracted wind projects representing 204 megawatts of generation capacity previously funded entirely with equity.

For information regarding third-party equity capital raised in February 2012 to finance the development of a portion of EMG's wind portfolio, see "Edison International Overview—Management Overview of EMG—EMG's Renewable Energy Activities" in the MD&A and "Item 8. Edison International and Subsidiaries Notes to Consolidated Financial Statements—Note 3. Variable Interest Entities—Categories of VIEs—Capistrano Wind Equity Capital-2012."

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During the fourth quarter of 2011, EMG significantly reduced its development activities to conserve cash and in light of more limited market opportunities. As a result, EMG reduced staffing and has undertaken efforts to reduce funding joint development projects, thereby reducing the development pipeline of potential wind projects to approximately 1,300 MW. Future development of the wind portfolio is dependent on the availability of third-party capital. To the extent that third-party capital is available, the success of development efforts will depend upon, among other things, obtaining permits and agreements necessary to support an investment.

Historical Segment Cash Flows

The table below sets forth condensed historical cash flow information for EMG.

	Years ended December 31,		
(in millions)	2011	2010	2009
Operating cash flow from continuing operations	$662	$306	$(985)
Operating cash flow from discontinued operations	(3)	4	(7)
Net cash provided (used) by operating activities	659	310	(992)
Net cash provided (used) by financing activities	277	336	(656)
Net cash provided (used) by investing activities	(674)	(732)	861
Net increase (decrease) in cash and cash equivalents	$262	$(86)	$(787)

Net Cash Provided (Used) by Operating Activities

Cash provided by operating activities from continuing operations increased $356 million in 2011 compared to 2010 primarily due to a $253 million deposit paid by Edison Capital to the IRS in 2010 related to Global Settlement and an increase in U.S. Treasury grants received by EME, partially offset by a decrease in operating income at EME due to declining energy prices, increasing operating costs, and higher interest payments due to new energy project financings.

Cash provided by operating activities from continuing operations increased $1.3 billion in 2010 compared to 2009 primarily due to the impacts of the Global Settlement. In April 2010, Edison Capital funded a $253 million deposit to the IRS related to the Global Settlement. In 2009, Edison Capital made a net tax-allocation payment to Edison International of $1.1 billion related to the termination of Edison Capital's interest in cross-border leases (see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 7. Income Taxes" for further discussion). The 2010 increase was also due to higher realized revenue from derivative contracts and payments on U.S. Treasury grants.

Net Cash Provided (Used) by Financing Activities

Cash provided by financing activities from continuing operations decreased $59 million in 2011 compared to 2010 primarily due to higher repayment of credit facilities by EME in 2011, partially offset by Edison Capital redeeming $89 million of its medium-term loans in 2010.

Cash provided by financing activities from continuing operations increased $1 billion in 2010 compared to 2009. In 2010, financing activities included project-level financing of renewable energy projects and repayment of credit facilities in 2009.

Net Cash Used by Investing Activities

Cash used by investing activities from continuing operations decreased $58 million in 2011 compared to 2010 primarily due to the timing of construction of EME's wind projects.

Cash used by investing activities from continuing operations decreased $1.6 billion in 2010 compared to 2009. The 2010 decrease was primarily due to $1.385 billion of net proceeds from termination of the cross-border leases at Edison Capital in 2009. The change was also due to the construction of wind projects.

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Credit Ratings

Credit ratings for EME, Midwest Generation and EMMT as of December 31, 2011 were as follows:

	Moody's Rating	S&P Rating	Fitch Rating
EME[1]	Caa1	B-	CCC
Midwest Generation[2]	Ba3	B+	BB-
EMMT	Not Rated	B-	Not Rated

[1] Senior unsecured rating.

[2] First priority senior secured rating.

All the above ratings are on negative outlook. 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 a requirement to make equity contributions or provide additional financial support to its subsidiaries, including EMMT. However, coal contracts at Midwest Generation include provisions that provide the right to request additional collateral to support payment obligations for delivered coal and may vary based on Midwest Generation's credit ratings. Furthermore, EMMT also has hedge contracts that do not require margin, 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.

Margin, Collateral Deposits and Other Credit Support for Energy Contracts

To reduce its exposure to market risk, EMG hedges a portion of its electricity price exposure through EMMT. 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, EME has historically also provided collateral in the form of cash and letters of credit for the benefit of counterparties. For further details, see "Edison International Notes to Consolidated Financial Statements—Note 6. Derivative Instruments and Hedging Activities."

Future cash collateral requirements may be higher than the margin and collateral requirements at December 31, 2011, if wholesale energy prices change or if EMMT enters into additional transactions. EMG estimates that margin and collateral requirements for energy and congestion contracts outstanding as of December 31, 2011 could increase by approximately $34 million over the remaining life of the contracts using a 95% confidence level.

Intercompany Tax-Allocation Agreement

EMG and its subsidiaries, 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 right 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. EMG received net tax-allocation payments of $241 million in 2011 and made net tax-allocation payments of $371 million and $1.1 billion in 2010 and 2009, respectively. EMG expects to make tax-allocation payments to Edison International during 2012 of approximately $185 million as a result of the reallocation of tax obligations from an expected Edison International consolidated net operating loss in 2011.

Debt Covenants and Dividend Restrictions

Dividend Restrictions in Major Financings

Each of EMG's direct or indirect subsidiaries is organized as a legal entity separate and apart from EMG and its other subsidiaries. Except for certain of EMG's wind projects in portfolio financings, assets of EMG's subsidiaries are not available to satisfy EMG's obligations or the obligations of any of its other subsidiaries. However, unrestricted cash or other assets that

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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 EMG's principal subsidiaries required by financing arrangements at December 31, 2011 or for the 12 months ended December 31, 2011:

Subsidiary	Financial Ratio	Covenant	Actual
Midwest Generation (Midwest Generation plants)	Debt to Capitalization Ratio	Less than or equal to 0.60 to 1	0.15 to 1
Homer City (Homer City plant)	Senior Rent Service Coverage Ratio	Greater than 1.7 to 1	1.18 to 1

As indicated above, the actual senior rent service coverage ratio of Homer City was below the covenant threshold for the 12 months ended December 31, 2011, and Homer City also did not meet the threshold for the prospective two 12-month periods, which currently precludes Homer City from making distributions, including repayment of certain intercompany loans and from paying the equity portion of the rent payment. For additional information, see "Edison International Overview—Management Overview of EMG—Homer City Lease."

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.

Homer City Sale-Leaseback Restrictions on Distributions

Homer City completed a sale-leaseback of the Homer City plant in December 2001. In order to make a distribution, 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 equity and debt portions of rent then due and payable must have been paid and the senior rent service coverage ratio for the prior 12-month period (taken as a whole and projected for each of the prospective two 12-month periods) must be greater than 1.7 to 1 in order to make the equity portion of the rent payment and other restricted payments. Homer City would be permanently restricted in its ability to make distributions if a failure to pay equity rent when due was not cured within nine months, or even if cured, occurred more than one additional time during the term of the lease. EME has not guaranteed Homer City's obligations under the leases. Homer City believes it is unlikely to meet the covenant requirements of its sale-leaseback agreements relating to the payment of equity rent at April 1, 2012, and will be unable to make the required equity rent payment. There is no assurance that subsequent rent payments will be made. For additional information, see "Edison International Overview—Management Overview of EMG—Homer City Lease."

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

EME is restricted under applicable agreements from selling or disposing of assets, which includes distributions, if the aggregate net book value of all such sales and dispositions 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 the sale or disposition in question. At December 31, 2011, the maximum permissible sale or disposition of EME assets was $778 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 as cash or cash equivalents or are used to repay debt.

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Contractual Obligations, Commercial Commitments and Contingencies

Contractual Obligations

EMG has contractual obligations and other commercial commitments that represent prospective cash requirements. The following table summarizes EMG's significant consolidated contractual obligations as of December 31, 2011.

		Payments Due by Period			
(in millions)	Total	Less than 1 year	1 to 3 years	3 to 5 years	More than 5 years
Long-term debt[1]	$7,042	$363	$1,594	$1,123	$3,962
Power plant and other operating lease obligations[2]	2,851	337	637	320	1,557
Purchase obligations[3]:					
Midwest Generation fuel supply contracts	518	223	295	—	—
Midwest Generation coal transportation agreements[4]	3,023	386	659	630	1,348
Homer City fuel supply contracts	267	214	53	—	—
Gas transportation agreements	46	7	14	15	10
Capital expenditures	305	286	19	—	—
Other contractual obligations	177	93	65	17	2
Employee benefit plan contribution[5]	120	21	48	51	—
Total Contractual Obligations[6,7]	$14,349	$1,930	$3,384	$2,156	$6,879

1 For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 5. Debt and Credit Agreements." Amount also includes interest payments totaling $2.1 billion over the applicable period of the debt.

2 At December 31, 2011, minimum operating lease payments were primarily related to long-term leases for the Powerton and Joliet Stations and the Homer City plant. For further discussion, see "—Off-Balance Sheet Transactions—Sale-Leaseback Transactions" and "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies."

3 For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies."

4 Years subsequent to 2012 represent contracts for minimum volumes without regard to payment of alternative liquidated damages or plant closures.

5 Amount includes estimated contribution for pension plans and postretirement benefits other than pensions. The estimated contributions beyond 2016 are not available. For more information, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 8. Compensation and Benefit Plans—Pension Plans and Postretirement Benefits Other than Pensions."

6 At December 31, 2011, EMG had a total net liability recorded for uncertain tax positions of $240 million, which is excluded from the table. EMG cannot make reliable estimates of the cash flows by period due to uncertainty surrounding the timing of resolving these open tax issues with the Internal Revenue Service. For more information, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 7. Income Taxes."

7 The contractual obligations table does not include derivative obligations and AROs, which are discussed in "Item 8. Edison International Notes to Consolidated Financial Statements—Note 6. Derivative Instruments and Hedging Activities," and "—Note 2. Property, Plant and Equipment," respectively.

Commercial Commitments

Standby Letters of Credit

As of December 31, 2011, standby letters of credit under EMG and its subsidiaries' credit facilities aggregated $177 million and were scheduled to expire as follows: $146 million in 2012 and $3 million in 2013, $10 million in 2017, and $18 million in 2018. Certain letters of credit are subject to automatic annual renewal provisions.

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Contingencies

EMG has contingencies related to the Midwest Generation NSR and other litigation, Homer City NSR and other litigation, and environmental remediation which are discussed in "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies."

Off-Balance Sheet Transactions

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

Investments Accounted for under the Equity Method

EMG has a number of investments in power projects that are accounted for under the equity method. For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 3. Variable Interest Entities."

Subsidiaries of EMG have invested in affordable housing projects utilizing partnership or limited liability companies in which EMG is a passive investor. With a few exceptions, an unrelated general partner or managing member exercises operating control of these projects and partnerships. The debt of those partnerships and limited liability companies is secured by real property. At December 31, 2011, entities that EMG has accounted for under the equity method had indebtedness of approximately $1.2 billion, of which approximately $318 million is proportionate to EMG's ownership interest in these projects. Substantially all of this debt is nonrecourse to EMG.

Sale-Leaseback Transactions

EMG 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 plant in Pennsylvania. For further discussion, see "Edison International Overview—Management Overview of EMG—Homer City Lease" and "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies—Power Plant and Other Lease Commitments."

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 (in millions)	Equity Investor	Original Equity Investment in Owner-Lessor (in millions)	Amount of Lessor Debt at December 31, 2011 (in millions)		Maturity Date of Lessor Debt
Powerton/Joliet	$1,367	PSEG/Citigroup, Inc.	$238	$460	Series B	2016
Homer City	$1,591	GECC/Metropolitan Life	$798	$183	Series A	2019
		Insurance Company		$477	Series B	2026

PSEG – PSEG Resources, Inc.

GECC – General Electric Capital Corporation

The operating lease payments to be made by each of EMG'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 EMG's consolidated balance sheet.

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 price fluctuations of electricity, capacity, fuel, emission allowances, and transmission rights. Additionally, EMG's financial results can be affected by fluctuations in interest rates. EMG manages these risks in part by using derivative instruments in accordance with established policies and procedures.

Derivative Instruments

EMG uses derivative instruments to reduce its exposure to market risks that arise from price fluctuations of electricity, capacity, fuel, emission allowances, and transmission rights. For derivative instruments recorded at fair value, changes in fair value are recognized in earnings at the end of each accounting period unless the instrument qualifies for hedge accounting.

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For derivatives that 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.

Unrealized Gains and Losses

EMG classifies unrealized gains and losses from derivative instruments (other than the effective portion of derivatives that qualify for hedge accounting) as part of operating revenues or fuel costs. The following table summarizes unrealized gains (losses) from non-trading activities:

	Years ended December 31,		
(in millions)	2011	2010	2009
Midwest Generation plants			
Non-qualifying hedges	$(2)	$(11)	$40
Ineffective portion of cash flow hedges	1	(2)	5
Homer City plant			
Non-qualifying hedges	(1)	(1)	1
Ineffective portion of cash flow hedges	6	(19)	14
Total unrealized gains (losses)	$4	$(33)	$60

At December 31, 2011, cumulative unrealized gains of $7 million were recognized from non-qualifying hedge contracts or the ineffective portion of cash flow hedges related to 2012.

Fair Value Disclosures

In determining the fair value of EMG's derivative positions, EMG uses third-party market pricing where available. For further explanation of the fair value hierarchy and a discussion of EMG's derivative instruments, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 4. Fair Value Measurements" and "—Note 6. Derivative Instruments and Hedging Activities," respectively.

The net fair value of commodity derivatives used for non-trading purposes at December 31, 2011 was $42 million. A 10% change in the market price of the underlying commodity at December 31, 2011 would increase or decrease the net fair value of non-trading commodity derivatives by approximately $26 million.

The net fair value of derivatives used for trading purposes at December 31, 2011 was $107 million. A 10% change in the market price of the underlying commodity at December 31, 2011 would increase or decrease the net fair value of trading contracts by approximately $19 million. The impact of changes to the various inputs used to determine the fair value of Level 3 derivatives would not be anticipated to be material to EME's results of operations as such changes would be offset by similar changes in derivatives classified within Level 3 as well as other levels. Level 3 assets and liabilities are 56% and 11%, respectively, of derivative assets and liabilities measured at fair value before the impact of offsetting collateral and netting as of December 31, 2011.

Commodity Price Risk

Introduction

EMG's merchant operations are exposed to commodity price risk, which reflects the potential impact of a change in the market value of a particular commodity. Commodity price risks are actively monitored, with oversight provided by a risk management committee, to ensure compliance with EMG's risk management policies. Despite this, there can be no assurance that all risks have been accurately identified, measured and/or mitigated.

Energy Price Risk

Energy and capacity from the coal plants are sold under terms, including price, duration 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. Power is sold into PJM at spot prices based upon locational marginal pricing. Energy from 428 MW of merchant renewable energy projects is sold in the energy markets, primarily at spot prices in PJM and ERCOT.

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The following table depicts the average historical market prices for energy per megawatt-hour at the locations indicated:

	24-Hour Average Historical Market Prices[1]		
	2011	2010	2009
Midwest Generation plants			
Northern Illinois Hub	$33.21	$33.12	$28.68
Homer City plant			
PJM West Hub	$43.57	$46.56	$38.75
Homer City Busbar	39.58	39.18	34.27

1 Energy prices were calculated at the Northern Illinois Hub and Homer City Busbar delivery points and the PJM West Hub using historical hourly day-ahead prices as published by PJM or provided on the PJM web-site.

The following table sets forth the forward market prices for energy per megawatt-hour as quoted for sales into the Northern Illinois Hub and PJM West Hub at December 31, 2011:

	24-Hour Forward Energy Prices[1]	
	Northern Illinois Hub	PJM West Hub
2012 calendar "strip"[2]	$29.75	$38.85
2013 calendar "strip"[2]	$31.41	$41.26

1 Energy prices were determined by obtaining broker quotes and information from other public sources relating to the Northern Illinois Hub and PJM West Hub delivery points.

2 Market price for energy purchases for the entire calendar year.

Power prices at the Northern Illinois Hub fell in the fourth quarter of 2011 and continued to fall in 2012 due to an abundance of low-priced natural gas and the sales volume from the Midwest Generation plants has been correspondingly affected. Forward market prices at the Northern Illinois Hub and 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 coal plants into these markets may vary materially from the forward market prices set forth in the preceding table.

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EMMT engages in hedging activities for the coal plants to hedge the risk of future change in the price of electricity. The following table summarizes the hedge positions (including load requirements services contracts and forward contracts accounted for on the accrual basis) as of December 31, 2011 for electricity expected to be generated in 2012 and 2013:

	2012		2013	
	MWh (in thousands)	Average price/ MWh[1]	MWh (in thousands)	Average price/ MWh[1]
Midwest Generation plants[2]	7,185	$38.76	1,020	$40.43
Homer City plant[3,4]				
PJM West Hub	432	52.34	—	—
Total	7,617		1,020	

1 The above hedge positions 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 are not directly comparable to the 24-hour Northern Illinois Hub or PJM West Hub prices set forth above.

2 Includes hedging transactions primarily at the Northern Illinois Hub and to a lesser extent the AEP/Dayton Hub, both in PJM, and the Indiana Hub in MISO.

3 Includes hedging transactions primarily at the PJM West Hub and to a lesser extent at other trading locations. 2012 includes hedging activities entered into by EMMT for the Homer City plant that are not designated under the intercompany agreements with Homer City due to limitations under the sale- leaseback transaction documents.

4 The average price/MWh includes 172 MW of capacity for periods ranging from January 1, 2012 to May 31, 2012 at Homer City sold in conjunction with load requirements services contracts.

In January 2012, EMMT entered into 14.7 billion cubic feet of natural gas futures contracts (equivalent to approximately 1,610 GWh of energy only contracts using a ratio of 9.12 MMBtu to 1 MWh) for the Midwest Generation plants to economically hedge energy price risks through December 2012 at an average price of $24.88/MWh.

Capacity Price Risk

Under the RPM, capacity commitments are made in advance to provide a long-term pricing signal for construction of capacity resources.

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The following table summarizes the status of capacity sales for Midwest Generation and Homer City at December 31, 2011:

				RPM Capacity Sold in Base Residual Auction		Other Capacity Sales, Net of Purchases[3]		
	Installed Capacity MW	Unsold Capacity[1] MW	Capacity Sold[2] MW	MW	Price per MW-day	MW	Average Price per MW-day	Aggregate Average Price per MW-day
January 1, 2012 to May 31, 2012								
Midwest Generation	5,477	(555)	4,922	4,582	$110.00	340	$98.92	$109.23
Homer City	1,884	(163)	1,721	1,771	110.00	(50)	30.00	112.32
June 1, 2012 to May 31, 2013								
Midwest Generation	5,477	(773)	4,704	4,704	16.46	—	—	16.46
Homer City	1,884	(232)	1,652	1,736	133.37	(84)	16.46	139.31
June 1, 2013 to May 31, 2014								
Midwest Generation	5,477	(827)	4,650	4,650	27.73	—	—	27.73
Homer City	1,884	(104)	1,780	1,780	226.15	—	—	221.03 [4]
June 1, 2014 to May 31, 2015								
Midwest Generation	5,477	(852)	4,625	4,625	125.99	—	—	125.99
Homer City	1,884	(190)	1,694	1,694	136.50	—	—	136.50

1 Capacity not sold arises from: (i) capacity retained to meet forced outages under the RPM auction guidelines, and (ii) capacity that PJM does not purchase at the clearing price resulting from the RPM auction.

2 Excludes 172 MW of capacity for periods ranging from January 1, 2012 to May 31, 2012 at Homer City sold in conjunction with load requirements services contracts.

3 Other capacity sales and purchases, net includes contracts executed in advance of the RPM base residual auction to hedge the price risk related to such auction, participation in RPM incremental auctions and other capacity transactions entered into to manage capacity risks.

4 Includes the impact of a 100 MW capacity swap transaction executed prior to the base residual auction at $135 per MW-day.

The RPM auction capacity prices for the delivery period of June 1, 2012 to May 31, 2013 and June 1, 2013 to May 31, 2014 varied between different areas of PJM. In the western portion of PJM, affecting Midwest Generation, the prices of $16.46 per MW-day and $27.73 per MW-day were substantially lower than other areas' capacity prices. The impact of lower capacity prices for these periods compared to previous years will have an adverse effect on Midwest Generation's revenues unless such lower capacity prices are offset by an unavailability of competing resources and increased energy prices.

Revenues from the sale of capacity from Midwest Generation and 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.

For additional information regarding capacity sold by Homer City, see "Edison International Overview—Management Overview of EMG—Homer City Lease."

Basis Risk

Sales made from the coal plants in the real-time or day-ahead market receive the actual real-time 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 forward spot prices at the individual plant busbars, EMG 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 plant and for settlement points at the Northern Illinois Hub and the AEP/Dayton and Indiana Hubs in the case of the Midwest Generation plants. EMG's hedging activities use these settlement points (and, to a lesser extent, other

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similar trading hubs) to enter into hedging contracts. 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 2011, day-ahead prices at the Homer City busbar were lower than those at the PJM West Hub by an average of 9%, compared to 16% during 2010 and 12% during 2009, due to transmission congestion in PJM. During 2011, day-ahead prices at the individual busbars of the Midwest Generation plants were lower than the AEP/Dayton Hub, Cinergy Hub and Northern Illinois Hub by an average of 14%, 4% and less than 1%, respectively, compared to 13%, 6% and less than 1%, respectively, during 2010, due to transmission congestion in PJM.

In order to mitigate basis risk, EMG may purchase financial transmission rights and basis swaps in PJM for Homer City and Midwest Generation. A financial transmission right is a financial instrument that entitles the holder to receive the difference between actual day-ahead prices for two delivery points in exchange for a fixed amount.

Coal and Transportation Price Risk

The Midwest Generation plants and Homer City plant purchase coal primarily 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. The following table summarizes the amount of coal under contract at December 31, 2011 for the following three years:

	Amount of Coal Under Contract in Millions of Equivalent Tons[1]		
	2012	2013	2014
Midwest Generation plants	16	9.8	9.8
Homer City plant	3.3	0.8	—

1 The amount of coal under contract in equivalent tons is calculated based on contracted tons and applying an 8,800 Btu equivalent for the Midwest Generation plants and 13,000 Btu equivalent for the Homer City plant.

EMG is subject to price risk for purchases of coal that are not under contract. Market prices of NAPP coal, which are related to the price of coal purchased for the Homer City plant, increased during the past two years. The market price of NAPP coal based on 13,000 Btu per pound heat content and <3.0 pounds of SO_2 per MMBtu sulfur content was $73.30 per ton at December 30, 2011, compared to a price of $70 per ton and $52.50 per ton at December 31, 2010 and 2009, respectively, as reported by the EIA. In 2011, the price of NAPP coal ranged from $70 per ton to $78.20 per ton, as reported by the EIA. The 2011 increase in NAPP coal prices was primarily driven by the export market demand and global coal pricing.

Market prices of PRB coal based on 8,800 Btu per pound heat content and 0.8 pounds of SO_2 per MMBtu sulfur content fluctuated between $12.35 per ton and $15.10 per ton during 2011, as reported by EIA. The December 30, 2011 price of $12.75 per ton compared to a price of $13.60 per ton and $9.25 per ton at December 31, 2010 and 2009, respectively, as reported by the EIA. The 2011 fluctuations in PRB coal prices were in line with normal market price volatility with the higher PRB prices reflecting the impact of the CSAPR before it was stayed.

Midwest Generation contracts with rail carriers to transport coal to its facilities. In anticipation of the expiration on December 31, 2011 of its existing rail transportation contracts, during the fourth quarter of 2011, Midwest Generation entered into new multi-year transportation contracts with Union Pacific Railroad and two short-haul carriers for a specified minimum and maximum amount of tons effective January 1, 2012. The estimated minimum annual costs of transportation of coal under these contracts, based on tonnage commitments, are $386 million during 2012, $326 million in 2013, and $333 million in 2014. However, all of the contracts have provisions that address the financial exposure of Midwest Generation related to a plant closure under certain circumstances as specified in the agreements. The contracts provide for quarterly and annual cost adjustments based on a number of factors that may increase the minimum payments.

EMG believes Midwest Generation is fully contracted in 2012 based on its anticipated coal requirements for Midwest Generation. Based on Homer City's anticipated coal requirements in excess of the amount under contract, Homer City expects that a 10% change in the price of coal at December 31, 2011 would increase or decrease 2012 pre-tax income by approximately $4 million.

Emission Allowances Price Risk

If CSAPR becomes effective as issued, the amount of SO_2 that a plant emits in its operation will need to be matched by a sufficient amount of SO_2 allowances designated under this program (CSAPR SO_2 allowances) that are either allocated to the

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plant under the CSAPR program or purchased in the open market. SO_2 allowances under the federal Acid Rain Program cannot be used to satisfy the requirements under CSAPR. For additional information on CSAPR, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 10. Environmental Developments—Cross-State Air Pollution Rule."

Credit Risk

For further information related to credit risk and how EMG manages credit risk, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 6. Derivative Instruments and Hedging Activities."

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. EMG'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, 2011, the balance sheet exposure as described above, by the credit ratings of EMG's counterparties, was as follows:

	December 31, 2011		
(in millions)	Exposure[2]	Collateral	Net Exposure
Credit Rating[1]			
A or higher	$99	$(2)	$97
A-	3	—	3
BBB+	4	—	4
BBB	—	—	—
BBB-	13	—	13
Below investment grade	51	(50)	1
Total	$170	$(52)	$118

1 EMG 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 composed of $82 million of net accounts receivable and payables and $88 million representing the fair value of derivative contracts. The exposure is based on master netting agreements with the related counterparties. Credit ratings may not be reflective of the actual related credit risks. In addition to the amounts set forth in the above table, EMG's subsidiaries have posted a $41 million cash margin in the aggregate with PJM, NYISO, MISO, clearing brokers and other counterparties to support hedging and trading activities. The margin posted to support these activities also exposes EMG to credit risk of the related entities.

The coal plants sell electric power generally into the PJM market by participating in PJM's capacity and energy markets or transacting in capacity and energy on a bilateral basis. Sales into PJM accounted for approximately 69% of EMG's consolidated operating revenues in 2011. At December 31, 2011, EMG's account receivable due from PJM was $62 million.

EMG's wind turbine supply agreements contain significant suppliers' obligations related to the manufacturing and delivery of turbines, and payments, for delays in delivery and for failure to meet performance obligations and warranty agreements. EMG'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 EMG's turbine suppliers may have a material impact on EMG's wind projects and development efforts.

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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. A 10% change in market interest rates at December 31, 2011 would increase or decrease the fair value of the interest rate swap agreements by approximately $21 million. The fair market values of fixed interest rate obligations are subject to interest rate risk. The fair market value of EMG's consolidated long-term debt (including current portion) was $3.7 billion at December 31, 2011, compared to the carrying value of $4.9 billion. A 10% increase in market interest rates at December 31, 2011 would result in a decrease in the fair value of total long-term debt by approximately $155 million. A 10% decrease in market interest rates at December 31, 2011 would result in an increase in the fair value of total long-term debt by approximately $172 million.

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EDISON INTERNATIONAL PARENT AND OTHER

RESULTS OF OPERATIONS

Results of operations for Edison International Parent and Other includes amounts from other Edison International subsidiaries that are not significant as a reportable segment, as well as intercompany eliminations.

Edison International Parent and Other earnings (loss) from continuing operations were $(33) million, $(8) million and $18 million for 2011, 2010 and 2009, respectively. Income tax benefits in 2011 included a cumulative deferred tax adjustment related to employee benefits and a consolidated tax expense (benefit) of $7 million, $(25) million and $(42) million in 2011, 2010 and 2009 respectively, representing differences in the allocation of state income taxes to subsidiaries under tax allocation agreements.

LIQUIDITY AND CAPITAL RESOURCES

Edison International Parent liquidity and its ability to pay operating expenses and dividends to common shareholders is dependent on dividends from SCE, tax-allocation payments under its tax-allocation agreements with its subsidiaries, and access to bank and capital markets.

At December 31, 2011, Edison International (parent) had approximately $28 million of cash and equivalents on hand. Edison International (parent) has a $1.4 billion revolving credit facility with various banks that terminates in February 2013. The following table summarizes the status of the Edison International (parent) credit facility at December 31, 2011:

(in millions)	Edison International (parent)
Commitment	$1,426
Outstanding borrowings	(10)
Outstanding letters of credit	—
Amount available	$1,416

Edison International has a debt covenant in its credit facility that requires a consolidated debt to total capitalization ratio of less than or equal to 0.65 to 1. At December 31, 2011, Edison International's consolidated debt to total capitalization ratio was 0.56 to 1.

Historical Segment Cash Flows

The table below sets forth condensed historical cash flow information for Edison International Parent and Other.

(in millions)	2011	2010	2009
Net cash used by operating activities	$(13)	$(218)	$(32)
Net cash provided (used) by financing activities	30	214	(273)
Net cash provided (used) by investing activities	1	11	(2)
Net increase (decrease) in cash and cash equivalents	$18	$7	$(307)

Net Cash Used by Operating Activities

Net cash used by operating activities primarily relate to interest, operating costs and income taxes of Edison International (parent). During 2010, Edison International received $134 million in state tax refunds related to Global Settlement and made tax-allocation payments to SCE of $295 million, resulting in a use of operating cash flows. Edison International funded a portion of the 2010 tax-allocation payments due by Edison Capital in consideration for repayment of intercompany loans.

See "Item 8. Edison International Notes to Consolidated Financial Statements—Note 7. Income Taxes" for further discussion of the Global Settlement.

Net Cash Provided (Used) by Financing Activities

Financing activities for 2011 were as follows:

- Paid $417 million of dividends to Edison International common shareholders.

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- Received $461 million of dividend payments from SCE.

Financing activities for 2010 were as follows:

- Issued $400 million of senior notes due in 2017. The proceeds from these bonds were used to repay short-term borrowings under the revolving credit facility and the remainder for corporate liquidity purposes.
- Paid $411 million of dividends to Edison International common shareholders.
- Received $300 million of dividend payments from SCE.
- Repaid a net $66 million of short-term debt.

Financing activities for 2009 were as follows:

- Paid $404 million of dividends to Edison International common shareholders.
- Repaid a net $165 million of short-term debt, primarily due to the improvement in economic conditions that occurred during the second half of 2008.
- Received $300 million of dividend payments from SCE.

Contractual Obligations

As of December 31, 2011, Edison International Parent and Other had outstanding debt of $400 million which matures in 2017. Interest in the amount of $15 million is payable annually in years 2012 through 2016 and $10.3 million is due in 2017.

MARKET RISK EXPOSURES

Interest Rate Risk

At December 31, 2011, the fair market value of Edison International Parent and Other's long-term debt (including current portion of long-term debt) was $416 million, compared to a carrying value of $399 million. A 10% increase in market interest rates would have resulted in a $6 million decrease in the fair market value of the long-term debt. A 10% decrease in market interest rates would have resulted in a $6 million increase in the fair market value of the long-term debt.

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EDISON INTERNATIONAL (CONSOLIDATED)
LIQUIDITY AND CAPITAL RESOURCES
Contractual Obligations

Edison International's contractual obligations as of December 31, 2011, for the years 2012 through 2016 and thereafter are estimated below.

(in millions)	Total	Less than 1 year	1 to 3 years	3 to 5 years	More than 5 years
Long-term debt maturities and interest[1]	$23,949	$812	$3,652	$2,564	$16,921
Power purchase agreements[2]					
Renewable energy contracts	16,578	561	1,328	1,503	13,186
Qualifying facility contracts	3,677	439	875	794	1,569
Other power purchase agreements	6,298	624	1,640	1,181	2,853
Power plant and other operating lease obligations[3]	3,492	410	772	429	1,881
Purchase obligations:[4]					
Nuclear fuel supply contract payments	1,068	190	213	206	459
Other fuel supply contract payments	1,053	479	445	129	—
Coal transportation agreements[5]	3,023	386	659	630	1,348
Gas transportation agreements	46	7	14	15	10
Capital expenditures	305	286	19		
Other contractual obligations[6]	500	114	116	56	214
Employee benefit plans contributions[7]	1,677	352	694	631	—
Total[8,9]	$61,666	$4,660	$10,427	$8,138	$38,441

1 For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 5. Debt and Credit Agreements." Amount includes interest payments totaling $10.2 billion over applicable period of the debt.

2 Certain power purchase agreements entered into with independent power producers are treated as operating or capital leases. At December 31, 2011, minimum operating lease payments for power purchase agreements were $839 million in 2012, $966 million in 2013, $930 million in 2014, $916 million in 2015, $815 million in 2016, and $11.5 billion for the thereafter period. At December 31, 2011, minimum capital lease payments for power purchase agreements were $33 million in 2012, $33 million 2013, $72 million for 2014, $109 million for 2015, $109 million for 2016, and $1.8 billion for the thereafter period (amounts include executory costs and interest of $445 million and $773 million, respectively). For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies."

3 At December 31, 2011, minimum operating lease payments were primarily related to long-term leases for the Powerton and Joliet stations and Homer City facilities and vehicles, office space and other equipment. For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies."

4 For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies."

5 Years subsequent to 2012 represent contracts for minimum volumes without regard to payment of alternative liquidated damages or plant closures.

6 For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies." In addition, at December 31, 2011, other commitments also related to maintaining reliability and expanding SCE's transmission and distribution system.

7 Amount includes estimated contributions to the pension and PBOP plans for Edison International through 2016. The estimated contributions are not available beyond 2016. These amounts represent estimates that are based on assumptions that are subject to change. In addition, funding of future contributions for SCE could be impacted by the final 2012 GRC decision. See "Item 8. Edison International Notes to Consolidated Financial Statements—Note 8. Compensation and Benefit Plans" for further information.

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8 At December 31, 2011, Edison International had a total net liability recorded for uncertain tax positions of $479 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.

9 The contractual obligations table does not include derivative obligations and asset retirement obligations, which are discussed in "Item 8. Edison International Notes to Consolidated Financial Statements—Note 6. Derivative Instruments and Hedging Activities," and "Item 8. Edison International Notes to Consolidated Financial Statements—Note 2. Property, Plant and Equipment," respectively.

Critical Accounting Estimates and Policies

The accounting policies described below are considered critical to obtaining an understanding of Edison International's consolidated financial statements because their application requires the use of significant estimates and judgments by management in preparing the consolidated financial statements. Management estimates and judgments are inherently uncertain and may differ significantly from actual results achieved. Management considers an accounting estimate to be critical if the estimate requires significant assumptions and changes in the estimate or, the use of alternative estimates, that could have a material impact on Edison International's results of operations or financial position. For more information on Edison International's accounting policies, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 1. Summary of Significant Accounting Policies."

Rate Regulated Enterprises

Nature of Estimate Required. SCE follows the accounting principles for rate-regulated enterprises which are required for entities whose rates are set by regulators at levels intended to recover the estimated costs of providing service, plus a return on net investment, or rate base. Regulators may also impose certain penalties or grant certain incentives. Due to timing and other differences in the collection of revenue, these principles allow a cost that would otherwise be charged as an expense by a unregulated entity to be capitalized as a regulatory asset if it is probable that such cost is recoverable through future rates; conversely the principles allow creation of a regulatory liability for amounts collected in rates to recover costs expected to be incurred in the future or amounts collected in excess of costs incurred.

Key Assumptions and Approach Used. SCE's management assesses at the end of each reporting period whether 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 or a similar incurred cost to SCE or other rate-regulated entities in California, and other factors that would indicate that the regulator will treat an incurred cost as allowable for ratemaking purposes. Using these factors, management has determined that existing regulatory assets and liabilities are probable of future recovery or settlement. This determination reflects the current regulatory climate in California and is subject to change in the future.

Effect if Different Assumption Used. Significant management judgment is required to evaluate the anticipated recovery of regulatory assets, the recognition of incentives and revenue subject to refund, as well as the anticipated cost of regulatory liabilities or penalties. 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, 2011, the consolidated balance sheets included regulatory assets of $6.0 billion and regulatory liabilities of $5.3 billion. If different judgments were reached on recovery of costs and timing of income recognition, SCE's earnings may vary from the amounts reported.

Impairment of Long-Lived Assets

Nature of Estimates Required. Long-lived assets, including intangible assets, are evaluated for impairment in accordance with applicable authoritative guidance. Authoritative guidance requires that if the undiscounted expected future cash flow from a company's assets or group of assets (without interest charges) is less than its carrying value, asset impairment must be recognized on the financial statements. The impairment charges, if applicable, are calculated as the excess of the asset's carrying value over its fair value, which represents the discounted expected future cash flows attributable to the asset or, in the case of assets expected to be sold, at fair value less costs to sell. Long-lived assets are evaluated for impairment whenever indicators exist or when there is a commitment to sell or dispose of the asset. These evaluations may result from significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as economic or operational analyses.

Key Assumptions and Approach Used. The assessment of impairment requires significant management judgment 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

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exists, the fair value of the asset or asset group. Factors that are considered 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 determination of fair value requires management to apply judgment in: (1) estimating future prices of energy and capacity in wholesale energy markets and fuel prices that are susceptible to significant change, (2) environmental and maintenance expenditures, and (3) the time period due to the length of the estimated remaining useful lives.

In preparing long-term cash forecasts, EMG includes assumptions about future prices for electricity, capacity, fuel and related products and services, as applicable, future operations and maintenance costs and future capital expenditure requirements under different scenarios. As appropriate, EME uses a probability weighted approach when determining whether impairment indicators exist. Assumptions included in the long-term cash flow forecasts for merchant projects include:

- Observable market prices for electricity, fuel and related products and services to the extent available and long-term prices developed based on a fundamental price model;
- Long-term capacity prices based on the assumption that capacity markets would continue consistent with their current structure, with expected increases in revenues as a result of declines in reserve margins beyond the price of the latest auctions;
- Trends for additions and retirements for generation resources; and
- Plans for compliance with both existing and possible future environmental regulations.

EMG includes allocated acquired emission allowances as part of each power plant asset group. In the case of the Powerton and Joliet Stations and Homer City, EMG also includes prepaid rent in the respective asset group. EMG'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.

Effect if Different Assumptions Used. The estimates and assumptions used to determine whether an impairment exists are subject to a high degree of uncertainty. The estimated fair value of an asset would change materially if different estimates and assumptions were used to determine the amounts or timing of future revenues, environmental compliance costs or operating expenditures.

Application to EMG's Homer City Plant

As described in "Management Overview of EMG," Homer City failed to obtain sufficient interest from market participants to fund the capital improvements during the process undertaken in the fourth quarter of 2011, and Homer City is currently engaged in discussions with the owner-lessors regarding the potential for such funding. EMG expects that the outcome of any such discussions, if successful in providing funding for the Homer City plant, will likely result in EMG's loss of substantially all beneficial economic interest in and material control of the Homer City plant. Failure to resolve the source of funding of necessary capital expenditures for the Homer City plant could result in Homer City's default under the lease agreements giving rise to remedies for the owner-lessors and secured lease obligation bondholders, which could include foreclosing on the leased assets, the general partner of Homer City, or both. In connection with the preparation of its year end financial statements, EMG concluded that these events combined with the current and projected financial condition of Homer City were indicators of impairment. The long-lived asset group subject to the impairment evaluation was determined to include the Homer City lease, leasehold improvements and prepaid rent. In assessing impairment, EMG concluded that the future undiscounted cash flows through the period in which EMG expects to continue to have significant economic interest and control of the Homer City plant were insufficient to recover the carrying amount of the asset group. To measure the amount of impairment loss, the market and income approaches were considered the most appropriate and resulted in a zero fair value. EMG viewed the lack of interest from market participants to provide sufficient funding for the capital improvements as indicative that the fair value of the asset group is zero. Furthermore, discounted cash flow analysis based on estimates of future energy, capacity and coal prices, operations and maintenance costs and operating lease payments along with the estimated costs of constructing the environmental control equipment also indicated a fair value of zero. Accordingly, EMG recorded an impairment charge of $1.03 billion for the fourth quarter of 2011.

Application to EMG's Midwest Generation Stations

A significant decline in power prices from September 30, 2011, combined with new environmental regulations and public policy pressure on coal generation have resulted in continuing uncertainties for merchant coal-fired power plants. In connection with the preparation of its year end financial statements, EMG concluded, based on the current energy price environment, it is less likely that Midwest Generation will install environmental controls required by the CPS at its Fisk,

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Crawford and Waukegan Stations; and such assessment was an indicator that these stations were impaired. Management updated the probability weighted future undiscounted cash flows expected to be received at these stations and concluded that such amounts did not recover the respective station's carrying amounts. As part of these alternative cash flow scenarios, management considered a shortened estimated useful life of each station if environmental improvements were not made and a forecasted reduction in generation from lower forward power prices. In February 2012, Midwest Generation decided to shut down the Fisk Station by the end of 2012 and the Crawford Station by the end of 2014.

To measure the amount of the impairment loss, the income approach was considered the most relevant, but market data obtained prior to the significant decline in power prices was used to corroborate the income approach. The discounted cash flow analysis assumptions that have the most significant impact on fair value are forecasted energy and capacity prices. The discounted cash flow analysis indicated a fair value of zero. EMG also concluded it was unlikely that a third party would consummate the purchase of the Fisk, Crawford or Waukegan Stations in the current economic and regulatory environment resulting in a determination that the fair value of each of these stations is zero. This resulted in an impairment charge of $115 million, $186 million and $339 million for Fisk, Crawford and Waukegan Stations, respectively. Environmental and other remediation or ongoing maintenance costs are expected to be offset by the salvage value of the asset groups.

The following table summarizes the net book value of the merchant coal-fired asset groups at December 31, 2011:

(in millions)	
Joliet Station	$732
Powerton Station	757
Will County Station	523

Application to Selected EMG Wind Projects

In connection with the preparation of its year end financial statements, management has reviewed the Storm Lake project and four small wind projects in Minnesota for impairment in the fourth quarter of 2011 based on an expected future increase in operating costs and declines in long-term power prices that the projects could potentially realize following the term of the power purchase agreements. The probability weighted future undiscounted cash flows of each project are not expected to be sufficient to recover the respective carrying value of each of these long-lived assets ($53 million in aggregate). The income approach was utilized to determine fair value for these asset groups. The most significant assumptions used in determining fair value were discount rates, future wind generation, the future availability of the project to generate energy and future plant operations expense. The asset groups at each project consisted of property, plant and equipment and, where appropriate, deferred revenue. In aggregate, the fair value of these five asset groups was determined to be $23 million, resulting in an impairment charge of $30 million.

EMG's Merchant Wind Projects

In light of the decline in forecasted power prices since September 30, 2011, EMG reviewed the long-term cash forecasts for the merchant wind projects in a manner consistent with the Key Assumptions and Approach Used described above. The expected future undiscounted cash flows of these projects recovered the carrying amount of these asset groups and, accordingly, no impairments were recorded. The expected future cash flows for these merchant wind projects are dependent upon a number of assumptions, the most significant of which are expected future power prices and operating costs. A decline in the forecasted cash flows in future periods could result in impairment, requiring a write-down of the carrying amount to fair value. The carrying values of the Goat Wind, Big Sky and Lookout asset groups at December 31, 2011 were $200 million, $344 million and $64 million, respectively.

Derivatives

Nature of Estimates Required. As described in "Item 8. Edison International Notes to Consolidated Financial Statements—Note 6. Derivative Instruments and Hedging Activities," SCE and EMG use derivative instruments to manage exposure to changes in electricity and fuel prices and interest rates. Derivative instruments are recorded at fair value unless certain exceptions are met in which case the derivative is recorded on an accrual basis.

SCE records derivative instruments that do not meet the normal purchases and sales exception at fair value with an offsetting regulatory asset or liability due to application of principles for rate-regulated enterprises. As a result, changes in fair value of SCE derivative instruments have no impact on earnings, but may temporarily affect cash flows. SCE has not elected to use hedge accounting for these transactions due to the regulatory accounting treatment. EMG records derivative instruments that do not meet the normal purchases and sales exception at fair value, with changes in

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the derivative's fair value recognized currently in earnings unless specific hedge accounting criteria are met. For derivatives that qualify for cash flow hedge accounting treatment, the effective portion of the changes in the derivative's fair value is recognized in other comprehensive income until the hedged item is recognized in earnings. EMG records derivative instruments used for trading at fair value with changes in fair value recognized in income. Management's judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal purchases and sales exception applies or whether individual transactions qualify for hedge accounting treatment. Management's judgment is also required to determine the fair value of derivative transactions.

Key Assumptions and Approach Used. SCE and EMG determine the fair value of derivative instruments based on forward market prices in active markets adjusted for nonperformance risk. If quoted market prices are not available, internally developed models are used to determine the fair value. 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 nonperformance risks, SCE and EMG review 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 nonperformance.

In addition, a fair value hierarchy is established that prioritizes the inputs to valuation techniques used to measure fair value. For further information, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 4. Fair Value Measurements."

Effect if Different Assumptions Used. As described above, fair value is determined using a combination of market information or observable data and unobservable inputs which reflect management's assumptions. Changes in observable data would impact results. In addition, unobservable inputs could have an impact on results. Fair value for Level 3 derivatives is derived using observable and unobservable inputs. As of December 31, 2011, the net fair value of EMG's Level 3 derivatives was an asset of $83 million. While it is difficult to determine the impact of a change in any one input, if the fair value of EMG's Level 3 derivatives were increased or decreased by 10%, the impact would be a $21 million increase or decrease to operating revenues. For EMG's derivative instruments that are measured at fair value using quantitative pricing models, a significant change in estimate could affect EMG's results of operations. As of December 31, 2011, the net fair value of SCE's Level 3 derivatives was a liability of $754 million. SCE recovers its hedging related costs through the energy resource recovery account ("ERRA") balancing account, and as a result, exposure to commodity price risk is not expected to impact earnings, but may impact cash flows. For further sensitivities in Edison International's assumptions used to calculate fair value, see "EMG: Results of Operations—Fair Value Disclosures" and "SCE: Market Risk Exposures—Fair Value of Derivative Instruments." For further information on derivative instruments, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 6. Derivative Instruments and Hedging Activities."

Nuclear Decommissioning–ARO

Nature of Estimate Required. Regulations by the NRC require SCE to decommission its nuclear power plants which is expected to begin after the plants' operating licenses expire. In accordance with authoritative guidance, SCE is required to record an obligation to decommission its nuclear facilities. Nuclear decommissioning costs are recovered in utility rates through contributions that are reviewed every three years by the CPUC. Due to regulatory accounting treatment, nuclear decommissioning activities are not expected to affect SCE earnings.

Key Assumptions and Approach Used. The liability to decommission SCE's nuclear power facilities is based on site-specific studies performed in 2008 and 2007 for San Onofre and Palo Verde, respectively, which estimate that SCE will spend approximately $8.6 billion through 2053 to decommission its active nuclear facilities. Decommissioning cost estimates are updated in each Nuclear Decommissioning Triennial Proceeding. The current estimate is based on the following assumptions from the 2008 and 2007 site-specific studies:

- Decommissioning Costs. The estimated costs for labor, dismantling and disposal costs, energy and miscellaneous costs.
-

Escalation Rates. Annual escalation rates are used to convert the decommissioning cost estimates in base year dollars to decommissioning cost estimates in future-year dollars. Escalation rates are primarily used for labor, material, equipment, and low level radioactive waste burial costs. SCE's current estimate is based on SCE's decommissioning cost methodology used for ratemaking purposes, escalated at rates ranging from 1.8% to 6.9% (depending on the cost element) annually.

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- Timing. Cost estimates are based on an assumption that decommissioning will commence promptly after the NRC operating licenses expire. The operating licenses currently expire in 2022 for San Onofre Units 2 and 3. When the site-specific study was completed, the licenses for the Palo Verde units were set to expire in 2025, 2026 and 2027. Effective April 2011, the licenses were extended to 2045, 2046 and 2047 for the Palo Verde units.
- Spent Fuel Dry Storage Costs. Cost estimates are based on an assumption that the DOE will begin to take spent fuel in 2015, and will remove the last spent fuel from the San Onofre and Palo Verde sites by 2051 and 2053, respectively. Costs for spent fuel monitoring are included until 2051 and 2053, respectively.
- Changes in decommissioning technology, regulation, and economics. The current cost studies assume the use of current technologies under current regulations and at current cost levels.

Effect if Different Assumptions Used. The ARO for decommissioning SCE's active nuclear facilities was $2.5 billion and $2.4 billion at December 31, 2011 and 2010, respectively. Changes in the estimated costs or timing of decommissioning, or in the assumptions and judgments by management underlying these estimates, could cause material revisions to the estimated total cost to decommission these facilities which could have a material effect on the recorded liability and related regulatory asset. The following table illustrates the increase to the ARO and regulatory asset if the escalation rate was adjusted while leaving all other assumptions constant:

(in millions)	Increase to ARO and regulatory asset at December 31, 2011
Uniform increase in escalation rate of 25 basis points	$146

Pensions and Postretirement Benefits Other than Pensions

Nature of Estimate Required. Authoritative accounting guidance 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). In accordance with authoritative guidance for rate-regulated enterprises, regulatory assets and liabilities are recorded instead of charges and credits to other comprehensive income (loss) for its postretirement benefit plans that are recoverable in utility rates. Edison International has a fiscal year-end measurement date for all of its postretirement plans.

Key Assumptions of Approach Used. 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.

As of December 31, 2011, Edison International's pension plans had a $4.5 billion benefit obligation and total expense for these plans was $144 million for 2011. As of December 31, 2011, Edison International's PBOP plans had a $2.6 billion benefit obligation and total expense for these plans was $44 million for 2011. Annual contributions made to most of SCE's pension plans are currently recovered through CPUC-approved regulatory mechanisms and are expected to be, at a minimum, equal to the related annual expense.

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The following are critical assumptions used to determine expense for pension and other postretirement benefit for 2011:

(in millions)	Pension Plans	Postretirement Benefits Other than Pensions
Discount rate[1]	5.25%	5.5%
Expected long-term return on plan assets[2]	7.5%	7.0%
Assumed health care cost trend rates[3]	—	9.75%

1 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-Hewitt.

2 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. A portion of PBOP trusts asset returns are subject to taxation, so the 7.5% rate of return on plan assets above is determined on an after-tax basis. Actual time-weighted, annualized returns on the pension plan assets were 2.2%, 2.0% and 5.9% for the one-year, five-year and ten-year periods ended December 31, 2011, respectively. Actual time-weighted, annualized returns on the PBOP plan assets were 1.2%, 0.8%, and 4.2% over these same periods. Accounting principles provide that differences between expected and actual returns are recognized over the average future service of employees.

3 The health care cost trend rate gradually declines to 5.5% for 2019 and beyond.

Pension expense is recorded for SCE based on the amount funded to the trusts, as calculated using an actuarial method required for ratemaking 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 ratemaking methods and pension expense calculated in accordance with authoritative accounting guidance for pension is accumulated as a regulatory asset or liability, and will, over time, be recovered from or returned to customers. As of December 31, 2011, this cumulative difference amounted to a regulatory asset of $105 million, meaning that the accounting method has recognized more in expense than the ratemaking method since implementation of authoritative guidance for employers' accounting for pensions in 1987.

As of December 31, 2011, Edison International had unrecognized pension costs of $1.1 billion and unrecognized PBOP costs of $749 million which primarily consisted of the cumulative impact of the reduced discount rates on the respective benefit obligations and the cumulative difference between the expected and actual rate of return on plan assets. Of these deferred costs, $989 million of pension costs and $714 million of PBOP costs are recorded as regulatory assets, an offset to the underfunded liabilities of these plans, and will be amortized to expense over the average expected future service of employees.

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 competitive power generation PBOP plans have no plan assets.

Effect if Different Assumptions Used. Changes in the estimated costs or timing of pension and other postretirement benefit obligations, or the assumptions and judgments used by management underlying these estimates, could have a material effect on the recorded expenses and liabilities. Earnings could be impacted if the CPUC eliminates or modifies the current approved SCE regulatory recovery mechanism.

The following table summarizes the increase or (decrease) to the projected benefit obligation for pension and the accumulated benefit obligation for PBOP if the discount rate were changed while leaving all other assumptions constant:

(in millions)	Increase in discount rate by 1%	Decrease in discount rate by 1%
Change to projected benefit obligation for pension	$(402)	$435

Change to accumulated benefit obligation for PBOP	(339	)394

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A one percentage point increase in the expected rate of return on pension plan assets would decrease current year expense by $32 million and a one percentage point increase in the expected rate of return on PBOP plan assets would decrease current year expense by $16 million.

The following table summarizes the increase or (decrease) to the accumulated benefit obligation and annual aggregate service and interest costs for PBOP if the health care cost trend rate was changed while leaving all other assumptions constant:

(in millions)	Increase in health care cost trend rate by 1%	Decrease in health care cost trend rate by 1%
Change to accumulated benefit obligation for PBOP	$297	$(247)
Change to annual aggregate service and interest costs	16	(13)

Income Taxes

Nature of Estimates Required. As part of the process of preparing its consolidated financial statements, Edison International is required to estimate its income taxes for each jurisdiction in which it operates. This process involves estimating actual current period 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 sheets.

Edison International takes certain tax positions it believes are applied in accordance with the applicable tax laws. However, these tax positions are subject to interpretation by the IRS, state tax authorities and the courts. Edison International determines its uncertain tax positions in accordance with the authoritative guidance.

Key Assumptions and Approach Used. Accounting for tax obligations requires management judgment. Management uses judgment in determining whether the evidence indicates it is more likely than not, based solely on the technical merits, that a tax position will be sustained, and to determine the amount of tax benefits to be recognized. Judgment is also used in determining the likelihood a tax position will be settled and possible settlement outcomes. In assessing its uncertain tax positions Edison International considers, among others, the following factors: the facts and circumstances of the position, regulations, rulings, and case law, opinions or views of legal counsel and other advisers, and the experience gained from similar tax positions. Management evaluates uncertain tax positions at the end of each reporting period and makes adjustments when warranted based on changes in fact or law.

Effect if Different Assumptions Used. Actual income taxes may differ from the estimated amounts which could have a significant impact on the liabilities, revenue and expenses recorded in the financial statements. Edison International continues to be under audit or subject to audit for multiple years in various jurisdictions. Significant judgment is required to determine the tax treatment of particular tax positions that involve interpretations of complex tax laws. A tax liability has been recorded with respect to tax positions in which the outcome is uncertain and the effect is estimable. Such liabilities are based on judgment and a final determination could take many years from the time the liability is recorded. Furthermore, settlement of tax positions included in open tax years may be resolved by compromises of tax positions based on current factors and business considerations that may result in material adjustments to income taxes previously estimated. See "Item 8. Edison International Notes to Consolidated Financial Statements—Note 7. Income Taxes" for a further discussion on income taxes.

Accounting for Contingencies, Guarantees and Indemnities

Nature of Estimates Required. 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. When a guarantee or indemnification subject to authoritative guidance is entered into, Edison International records a liability for the estimated fair value of the underlying guarantee or indemnification. Gain contingencies are recognized in the financial statements when they are realized.

Key Assumptions and Approach Used. The determination of a reserve for a loss contingency is based on management judgment and estimates with respect to the likely outcome of the matter, including the analysis of different scenarios. Liabilities are recorded or adjusted when events or circumstances cause these judgments or estimates to change. In assessing whether a loss is a reasonable possibility, Edison International may consider the following factors, among others: the nature of the litigation, claim or assessment, available information, opinions or views of legal counsel and other advisors, and the experience gained from similar cases. Edison International provides disclosures for material contingencies when there is a reasonable possibility that a loss or an additional loss may be incurred. Some guarantees and indemnifications could have a

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significant financial impact under certain circumstances, and management also considers the probability of such circumstances occurring when estimating the fair value.

Effect if Different Assumptions Used. 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 on the consolidated financial statements. In addition, for guarantees and indemnities actual results may differ from the amounts recorded and disclosed and could have a significant impact on Edison International's consolidated financial statements. For a discussion of contingencies, guarantees and indemnities, see "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies."

NEW ACCOUNTING GUIDANCE

New accounting guidance is discussed in "Item 8. Edison International Notes to Consolidated Financial Statements—Note 1. Summary of Significant Accounting Policies—New Accounting Guidance."

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information responding to Item 7A is included in the MD&A under the headings "SCE: Market Risk Exposures" and "EMG: Market Risk Exposures."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and
Shareholders of Edison International

In our opinion, the consolidated balance sheets and related consolidated statements of income, comprehensive income, cash flows and changes in equity present fairly, in all material respects, the financial position of Edison International (the "Company") and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the index appearing under Item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, 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 and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, 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 Note 3 to the consolidated financial statements, the Company changed the manner in which it accounts for variable interest entities as of January 1, 2010.

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.

/s/ PricewaterhouseCoopers LLP
Los Angeles, California
February 29, 2012

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Consolidated Statements of Income — Edison International

(in millions, except per-share amounts)	Years ended December 31, 2011	2010	2009
Electric utility	$10,574	$9,980	$9,962
Competitive power generation	2,186	2,429	2,399
Total operating revenue	12,760	12,409	12,361
Fuel	1,166	1,172	1,517
Purchased power	2,989	2,930	2,751
Operations and maintenance	4,776	4,612	4,387
Depreciation, decommissioning and amortization	1,737	1,522	1,418
Asset impairments, lease terminations and other	1,772	47	890
Total operating expenses	12,440	10,283	10,963
Operating income	320	2,126	1,398
Interest and dividend income	37	31	32
Equity in income from unconsolidated affiliates – net	86	106	42
Other income	156	148	171
Interest expense	(808)	(703)	(732)
Other expenses	(55)	(51)	(57)
Income (loss) from continuing operations before income taxes	(264)	1,657	854
Income tax expense (benefit)	(288)	354	(98)
Income from continuing operations	24	1,303	952
Income (loss) from discontinued operations, net of tax	(3)	4	(7)
Net income	21	1,307	945
Dividends on preferred and preference stock of utility	59	52	51
Other noncontrolling interests	(1)	(1)	45
Net income (loss) attributable to Edison International common shareholders	$(37)	$1,256	$849
Amounts attributable to Edison International common shareholders:			
Income (loss) from continuing operations, net of tax	$(34)	$1,252	$856
Income (loss) from discontinued operations, net of tax	(3)	4	(7)
Net income (loss) attributable to Edison International common shareholders	$(37)	$1,256	$849
Basic earnings (loss) per common share attributable to Edison International common shareholders:			
Weighted-average shares of common stock outstanding	326	326	326
Continuing operations	$(0.10)	$3.83	$2.61
Discontinued operations	(0.01)	0.01	(0.02)
Total	$(0.11)	$3.84	$2.59
Diluted earnings (loss) per common share attributable to Edison International common shareholders:			
Weighted-average shares of common stock outstanding, including effect of dilutive securities	326	329	327
Continuing operations	$(0.10)	$3.81	$2.60
Discontinued operations	(0.01)	0.01	(0.02)
Total	$(0.11)	$3.82	$2.58
Dividends declared per common share	$1.285	$1.265	$1.245

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

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Consolidated Statements of Comprehensive Income | Edison International

	Years ended December 31,		
(in millions)	2011	2010	2009
Net income	$21	$1,307	$945
Other comprehensive income (loss), net of tax:			
Foreign currency translation adjustments – net	—	—	4
Pension and postretirement benefits other than pensions:			
Net loss arising during the period, net of income tax benefit of $14, $22 and $3 for 2011, 2010 and 2009, respectively	(21)	(23)	(13)
Amortization of net loss included in net income, net of income tax expense of $5, $4 and $8 for 2011, 2010 and 2009, respectively	8	6	13
Prior service credit arising during the period, net of income tax expense of $4 for 2010	—	(6)	—
Amortization of prior service credit, net of income tax expense	—	(1)	1
Unrealized gain (loss) on derivatives qualified as cash flow hedges:			
Unrealized holding gain (loss) arising during the period, net of income tax expense (benefit) of $(7), $37 and $36 for 2011, 2010 and 2009, respectively	(12)	55	43
Reclassification adjustments included in net income, net of income tax benefit of $25, $96 and $124 for 2011, 2010 and 2009, respectively	(38)	(144)	(178)
Other comprehensive loss	(63)	(113)	(130)
Comprehensive income (loss)	(42)	1,194	815
Less: Comprehensive income attributable to noncontrolling interests	58	51	96
Comprehensive income (loss) attributable to Edison International	$(100)	$1,143	$719

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

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Consolidated Balance Sheets | Edison International

(in millions)	December 31, 2011	2010
ASSETS		
Cash and cash equivalents	$1,469	$1,389
Receivables, less allowances of $75 and $85 for uncollectible accounts at respective dates	908	931
Accrued unbilled revenue	519	442
Inventory	624	568
Prepaid taxes	88	390
Derivative assets	106	133
Restricted cash and cash equivalents	103	2
Margin and collateral deposits	58	65
Regulatory assets	494	378
Other current assets	115	124
Total current assets	4,484	4,422
Nuclear decommissioning trusts	3,592	3,480
Investments in unconsolidated affiliates	525	559
Other investments	211	223
Total investments	4,328	4,262
Utility property, plant and equipment, less accumulated depreciation of $6,894 and $6,319 at respective dates	27,569	24,778
Competitive power generation and other property, plant and equipment, less accumulated depreciation of $1,408 and $1,865 at respective dates	4,547	5,406
Total property, plant and equipment	32,116	30,184
Derivative assets	128	437
Restricted deposits	51	47
Rent payments in excess of levelized rent expense under plant operating leases	760	1,187
Regulatory assets	5,466	4,347
Other long-term assets	706	644
Total long-term assets	7,111	6,662
Total assets	$48,039	$45,530

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

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Consolidated Balance Sheets Edison International

(in millions, except share amounts)	December 31, 2011	2010
LIABILITIES AND EQUITY		
Short-term debt	$429	$115
Current portion of long-term debt	57	48
Accounts payable	1,419	1,362
Accrued taxes	52	52
Accrued interest	205	205
Customer deposits	199	217
Derivative liabilities	268	217
Regulatory liabilities	670	738
Other current liabilities	1,049	998
Total current liabilities	4,348	3,952
Long-term debt	13,689	12,371
Deferred income taxes	5,396	5,625
Deferred investment tax credits	89	122
Customer advances	138	112
Derivative liabilities	547	468
Pensions and benefits	2,912	2,260
Asset retirement obligations	2,688	2,561
Regulatory liabilities	4,670	4,524
Other deferred credits and other long-term liabilities	2,476	2,041
Total deferred credits and other liabilities	18,916	17,713
Total liabilities	36,953	34,036
Commitments and contingencies (Note 9)		
Common stock, no par value (800,000,000 shares authorized; 325,811,206 shares issued and outstanding at each date)	2,360	2,331
Accumulated other comprehensive loss	(139)	(76)
Retained earnings	7,834	8,328
Total Edison International's common shareholders' equity	10,055	10,583
Preferred and preference stock of utility	1,029	907
Other noncontrolling interests	2	4
Total noncontrolling interests	1,031	911
Total equity	11,086	11,494
Total liabilities and equity	$48,039	$45,530

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

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Consolidated Statements of Cash Flows — Edison International

(in millions)	Years ended December 31, 2011	2010	2009
Cash flows from operating activities:			
Net income	$21	$1,307	$945
Less: Income (loss) from discontinued operations	(3)	4	(7)
Income from continuing operations	24	1,303	952
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	1,737	1,522	1,418
Regulatory impacts of net nuclear decommissioning trust earnings	146	189	158
Other amortization	152	118	120
Asset impairments, lease terminations and other	1,759	47	888
Stock-based compensation	30	30	22
Equity in income from unconsolidated affiliates	(86)	(106)	(42)
Distributions from unconsolidated affiliates	82	92	31
Deferred income taxes and investment tax credits	(188)	1,139	(1,457)
Income from leveraged leases	(5)	(5)	(14)
Proceeds from U.S. treasury grants	388	92	—
Changes in operating assets and liabilities:			
Receivables	19	(155)	80
Inventory	(56)	(49)	20
Margin and collateral deposits – net of collateral received	25	63	30
Prepaid taxes	302	(357)	178
Other current assets	(85)	(24)	(45)
Rent payments in excess of levelized rent expense	(136)	(149)	(160)
Accounts payable	56	(3)	152
Accrued taxes	—	(135)	(402)
Other current liabilities	(33)	13	31
Derivative assets and liabilities – net	383	(44)	(581)
Regulatory assets and liabilities – net	(1,080)	278	1,457
Other assets	(120)	(71)	62
Other liabilities	595	(315)	154
Operating cash flows from discontinued operations	(3)	4	(7)
Net cash provided by operating activities	3,906	3,477	3,045
Cash flows from financing activities:			
Long-term debt issued	1,376	1,936	939
Long-term debt issuance costs	(35)	(38)	(25)
Long-term debt repaid	(67)	(396)	(1,044)
Bonds purchased	(86)	—	(219)
Preference stock issued – net	123	—	—
Short-term debt financing – net	389	30	(2,058)
Borrowing held in escrow pending completion of project construction	(97)	—	—
Settlements of stock-based compensation – net	(20)	(16)	(3)
Cash contributions from noncontrolling interests	—	—	2
Dividends and distributions to noncontrolling interests	(59)	(52)	(117)
Dividends paid	(417)	(411)	(404)
Net cash provided (used) by financing activities	$1,107	$1,053	$(2,929)

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

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Consolidated Statements of Cash Flows Edison International

(in millions)	Years ended December 31, 2011	2010	2009
Cash flows from investing activities:			
Capital expenditures	$(4,808)	$(4,543)	$(3,282)
Purchase of interest in acquired companies	(3)	(4)	(22)
Proceeds from termination of leases	—	—	1,420
Proceeds from sale of nuclear decommissioning trust investments	2,773	1,432	2,217
Purchases of nuclear decommissioning trust investments and other	(2,940)	(1,651)	(2,416)
Proceeds from partnerships and unconsolidated subsidiaries, net of investment	41	44	11
Investments in other assets	4	(1)	(287)
Effect of consolidation and deconsolidation of variable interest entities	—	(91)	—
Net cash used by investing activities	(4,933)	(4,814)	(2,359)
Net increase (decrease) in cash and cash equivalents	80	(284)	(2,243)
Cash and cash equivalents, beginning of year	1,389	1,673	3,916
Cash and cash equivalents, end of year	$1,469	$1,389	$1,673

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

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Consolidated Statements of Changes in Equity | Edison International

(in millions)	Equity Attributable to Edison International: Common Stock	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Subtotal	Noncontrolling Interests: Other	Preferred and Preference Stock	Total Equity
Balance at December 31, 2008	$2,272	$167	$7,078	$9,517	$285	$907	$10,709
Net income	—	—	849	849	45	51	945
Other comprehensive loss	—	(130)	—	(130)	—	—	(130)
Common stock dividends declared ($1.245 per share)	—	—	(406)	(406)	—	—	(406)
Dividends, distributions to noncontrolling interests and other	—	—	—	—	(72)	(51)	(123)
Stock-based compensation – net	9	—	(12)	(3)	—	—	(3)
Noncash stock-based compensation and other	23	—	(9)	14	—	—	14
Balance at December 31, 2009	$2,304	$37	$7,500	$9,841	$258	$907	$11,006
Net income (loss)	—	—	1,256	1,256	(1)	52	1,307
Other comprehensive loss	—	(113)	—	(113)	—	—	(113)
Deconsolidation of variable interest entities	—	—	—	—	(249)	—	(249)
Cumulative effect of a change in accounting principle, net of tax	—	—	15	15	—	—	15
Common stock dividends declared ($1.265 per share)	—	—	(412)	(412)	—	—	(412)
Dividends, distributions to noncontrolling interests and other	—	—	—	—	(4)	(52)	(56)
Stock-based compensation – net	8	—	(24)	(16)	—	—	(16)
Noncash stock-based compensation and other	19	—	(7)	12	—	—	12
Balance at December 31, 2010	$2,331	$(76)	$8,328	$10,583	$4	$907	$11,494
Net income (loss)	—	—	(37)	(37)	(1)	59	21
Other comprehensive loss	—	(63)	—	(63)	—	—	(63)
	—	—	(419)	(419)	—	—	(419)

Common stock dividends declared ($1.285 per share)							
Dividends, distributions to noncontrolling interests and other	—	—	—	—	(1)	(59)	(60)
Stock-based compensation and other	14	—	(34)	(20)	—	—	(20)
Noncash stock-based compensation and other	30	—	(4)	26	—	(1)	25
Purchase of noncontrolling interests	(15)	—	—	(15)	—	—	(15)
Issuance of preference stock	—	—	—	—	—	123	123
Balance at December 31, 2011	$2,360	$(139)	$7,834	$10,055	$2	$1,029	$11,086

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Summary of Significant Accounting Policies

Edison International has two business segments for financial reporting purposes: an electric utility segment (SCE) and a competitive power generation segment (EMG). SCE is an investor-owned public utility primarily engaged in the business of supplying electricity to an approximately 50,000 square mile area of southern California. EMG is the holding company for its principal wholly owned subsidiary, EME. EME is a holding company with subsidiaries and affiliates engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from independent power production facilities. EME also engages in hedging and energy trading activities in competitive power markets through its Edison Mission Marketing & Trading, Inc. ("EMMT") subsidiary.

Basis of Presentation

The consolidated financial statements included Edison International and its wholly owned subsidiaries. Edison International consolidates subsidiaries in which it has a controlling interest and Variable Interest Entities ("VIEs") in which it is 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 but less than controlling interest and (2) VIEs in which it is not the primary beneficiary. Intercompany transactions have been eliminated, except EMG's profits from energy sales to SCE which are allowed in utility rates.

Edison International'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 ratemaking policies of the California Public Utility Commission ("CPUC") and the Federal Energy Regulatory Commission ("FERC"). SCE applies authoritative guidance for rate-regulated enterprises 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. Regulators may also impose certain penalties or grant certain incentives. Due to timing and other differences in the collection of electric utility revenue, these principles require 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 the principles require recording of a regulatory liability for amounts collected in rates to recover costs expected to be incurred in the future or amounts collected in excess of costs incurred. SCE assesses, at the end of each reporting period, whether regulatory assets are probable of future recovery. See Note 14 for composition of regulatory assets and liabilities.

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

Cash Equivalents

Cash equivalents included investments in money market funds totaling $1.3 billion and $1.1 billion at December 31, 2011 and 2010, respectively. Generally, the carrying value of cash equivalents equals the fair value, as these investments have maturities of three months or less.

Edison International temporarily invests the ending daily cash balance in its primary disbursement accounts until required for check clearing. Edison International reclassified $220 million and $197 million of checks issued, but not yet paid by the financial institution, from cash to accounts payable at December 31, 2011 and 2010, respectively.

Restricted Cash and Cash Equivalents, and Restricted Deposits

Restricted deposits consisted of cash balances that are restricted to pay amounts required for lease payments, debt service or to provide collateral. Included in restricted deposits was $51 million and $47 million at December 31, 2011 and 2010, respectively, related to lease payments, debt service, collateral reserves, or other. The restricted cash and cash equivalents at December 31, 2011 included $97 million of cash proceeds received from a wind financing that was held in escrow at December 31, 2011 and is expected to be released in the first quarter of 2012 when the Pinnacle project achieves certain completion milestones.

Allowance for Uncollectible Accounts

SCE records an allowance for uncollectible accounts, based upon a variety of factors, including historical amounts written-off, current economic conditions and assessment of customer collectability.

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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. Inventory consisted of the following:

	December 31,	
(in millions)	2011	2010
Coal, gas, fuel oil and other raw materials	$211	$184
Spare parts, materials and supplies	413	384
Total inventory	$624	$568

Purchased Emission Allowances, Exemptions and Offsets

Purchased emission allowances are stated at the lower of weighted-average cost or market. Purchased emission allowances are recorded at cost when purchased and then expensed at weighted-average cost as used. Cost is reduced to market value if the market value of emission allowances has declined and it is probable that revenues earned from the generation of power will not cover the amounts recorded in the ordinary course of business. Purchased emission allowances are classified as current or long-term assets based on the time the allowances are expected to be used. The following table summarizes the amount of current and noncurrent purchased emission allowances, exemptions and offsets and the line item on the consolidated balance sheets.

	December 31,	
(in millions)	2011	2010
Purchased emission allowances		
Current (included in other current assets)	$20	$29
Noncurrent (included in other long-term assets)	92	31

Renewable Energy Credits

Renewable energy certificates or credits ("RECs") represent property rights established by governmental agencies for the environmental, social, and other nonpower qualities of renewable electricity generation. A REC, and its associated attributes and benefits, can be sold separately from the underlying physical electricity associated with a renewable-based generation source in certain markets.

Retail sellers of electricity obtain RECs through renewable power purchase agreements, internal generation or separate purchases in the market to comply with renewable portfolio standards established in certain such governmental agencies. RECs are the mechanism used to verify renewable portfolio standards compliance and are recognized at the lower of weighted-average cost or market when amounts purchased are in excess of the amounts needed to comply with RPS requirements. The cost of RECs is recoverable as part of the cost of purchased power by SCE.

Property, Plant and Equipment

Utility Property, Plant and Equipment

Utility plant additions, including replacements and betterments, are capitalized. Such costs include direct material and labor and indirect costs such as construction overhead, administrative and general costs, pension and benefits, and property taxes. The CPUC authorizes a rate for each of the indirect costs which are allocated to each project based on either labor or total costs. In addition, allowance for funds used during construction ("AFUDC") is capitalized for certain projects.

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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	25 years to 70 years	40 years
Distribution plant	30 years to 60 years	40 years
Transmission plant	35 years to 65 years	46 years
General and Other plant	5 years to 60 years	22 years

Depreciation of utility property, plant and equipment is computed on a straight-line, remaining-life basis. Depreciation expense stated as a percent of average original cost of depreciable utility plant was, on a composite basis, 4.3%, 4.1% and 4.2% for 2011, 2010 and 2009, respectively. Replaced or retired property costs are charged to the accumulated provision for depreciation. Cash payments for removal costs less salvage reduce the liability for asset retirement obligations ("AROs").

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 ratemaking procedures. Nuclear fuel is amortized using the units of production method.

AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction and is capitalized during certain plant construction. AFUDC is recovered in rates through depreciation expense over the useful life of the related asset. AFUDC equity represents a method to compensate SCE for the estimated cost of equity used to finance utility plant additions and is recorded as part of construction in progress. AFUDC equity was $96 million, $100 million and $116 million in 2011, 2010 and 2009, respectively. AFUDC debt was $42 million, $41 million and $32 million in 2011, 2010 and 2009, respectively.

The FERC issued an order granting return on equity ("ROE") incentive adders, recovery of the return on rate base including incentive adders during the construction phase (referred to as CWIP) and recovery of abandoned plant costs, if needed, for several of SCE's transmission projects. In addition, the FERC granted an ROE incentive to SCE for California Independent System Operator ("CAISO") participation. The order permits SCE to include 100% of prudently-incurred capital expenditures in rate base during construction of the projects and earn a return on equity, rather than capitalizing AFUDC.

Competitive Power Generation and Other Property

Property, plant and equipment, including leasehold improvements and construction in progress, are capitalized at cost and are principally comprised of EMG's majority-owned subsidiaries' plants and related facilities and, prior to January 1, 2010, the plant and related facilities of VIEs consolidated by SCE. Depreciation and amortization are computed using the straight-line method over the estimated useful life of the property, plant and equipment and over the shorter of the lease term or estimated useful life for leasehold improvements. Gains and losses from sale of assets are recognized at the time of the transaction.

As part of the acquisition of the Midwest Generation plants and Homer City plant, EMG acquired emission allowances under the United States Environmental Protection Agency's (US EPA's) Acid Rain Program. EMG uses these emission allowances in the normal course of its business to generate electricity and has classified them as part of property, plant and equipment. Acquired emission allowances will be amortized on a straight-line basis.

Estimated useful lives for property, plant and equipment are as follows:

Power plant facilities	3 to 35 years
Leasehold improvements	Shorter of life of lease or estimated useful life
Emission allowances	25 to 33.75 years
Equipment, furniture and fixtures	3 to 10 years

Interest incurred on funds borrowed by EMG is capitalized during the construction period. Such capitalized interest is included in property, plant and equipment. Capitalized interest is amortized over the depreciation period of the major plant and facilities for the respective project. Capitalized interest was $27 million, $54 million and $19 million in 2011, 2010 and 2009, respectively.

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Major Maintenance

Certain of Edison International's power plant facilities and equipment require periodic major maintenance. These costs are expensed as incurred.

Asset Retirement Obligations

The fair value of a liability for an ARO is recorded in the period in which it is incurred, including a liability for the fair value of a conditional ARO, if the fair value can be reasonably estimated even though uncertainty exists about the timing and/or method of settlement. When an ARO liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased for accretion expense 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 an increase or decrease in expense. AROs related to decommissioning of SCE's nuclear power facilities are based on site-specific studies. Those site-specific studies are updated as part of each Nuclear Decommissioning Cost Triennial Proceeding ("NDCTP"). The initial establishment of a nuclear-related ARO is at fair value. Subsequent layers of an ARO are established for updated site-specific decommissioning cost estimates as approved by the CPUC on the NDCTP. For further discussion, see "Nuclear Decommissioning" below and Notes 4 and 15. A reconciliation of the changes in the ARO liability is as follows:

(in millions)	2011	2010
Beginning balance	$2,561	$3,241
Accretion expense	68	198
Revisions[1]	41	(867)
Liabilities added	19	9
Liabilities settled	(1)	(1)
Transfers in or out[2]	—	(19)
Ending balance	$2,688	$2,561

1 Revisions in 2010 represent the most recent site-specific studies approved by the CPUC.

2 Transfers in or out consist of the deconsolidation of the Big 4 projects (Kern River, Midway-Sunset, Sycamore and Watson) effective January 1, 2010. For further discussion, see Note 3.

In 2003, SCE recorded the fair value of its liability for AROs 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 and the recovery of costs through the ratemaking process. Once a Commission decision is rendered, a revised ARO layer reflecting the updated cost estimate is established and accreted over the lives of San Onofre and Palo Verde. The ARO liability related to San Onofre and Palo Verde was $2.5 billion at both December 31, 2011 and 2010.

Impairment of 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 that the carrying amount of such investments or assets may not be recoverable. Edison International'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. If the carrying amount of a long-lived asset exceeds expected future cash flows, undiscounted and without interest charges, an impairment loss is recognized in the amount of the excess of fair value over the carrying amount. Fair value is determined via market, cost and income based valuation techniques, as appropriate. SCE's impaired assets are recorded as a regulatory asset if it is deemed probable that such amounts will be recovered from customers. For further discussion, see Note 16.

Project Development Costs

Edison International capitalizes project development costs incurred in the assessment, design and construction of generating projects once it is probable that the project will be completed. Edison International determines it is probable that the project will be completed based upon management's determination that the project is economically and operationally feasible and appropriate management and regulatory approvals have been obtained or are probable. Project development costs consist of professional fees, permits and other directly related development costs incurred by Edison International. The capitalized costs

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are recorded in other long-term assets on Edison International's consolidated balance sheets until the start of construction, at which time the costs are transferred to construction in progress, a component of property, plant and equipment. The capitalized costs are amortized over the life of the projects once operational or charged to expense if management determines the costs to be unrecoverable.

Leases

SCE and EMG enter into power purchase agreements that may contain leases, as discussed under "Power Purchase Agreements" below. EMG leases the Homer City, Powerton and a portion of the Joliet power plants under sales leaseback arrangements as described in Note 9. Both SCE and EMG have entered into a number of agreements to lease property and equipment in the normal course of business. 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 in "Other deferred credits and other long-term liabilities." As a rate-regulated enterprise, SCE's capital lease amortization expense and interest expense are reflected in "Purchased power" on the consolidated statements of income.

Nuclear Decommissioning

SCE plans to decommission its nuclear generating facilities by a prompt removal method authorized by the NRC. Decommissioning is expected to begin after expiration of the plants' operating licenses. The plants' operating licenses are currently set to expire in 2022 for San Onofre Units 2 and 3, unless license renewal proves feasible, and 2045, 2046 and 2047 for Palo Verde units 1, 2 and 3, respectively. 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. Amortization of the ARO asset (included within the unamortized nuclear investment) and accretion of the ARO liability are deferred as increases to the ARO regulatory liability account, resulting in no impact on earnings.

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.

Due to regulatory recovery of SCE's nuclear decommissioning expense, nuclear decommissioning activities do not affect SCE's earnings. SCE's nuclear decommissioning trust investments primarily consist of debt and equity investments that are classified as available-for-sale. 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 on the last day of each month. If the fair value on the last day of two consecutive months is less than the cost for that security, SCE recognizes a 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 recognizes a related realized gain or loss, respectively.

Deferred Financing Costs

Debt premium, discount and issuance expenses incurred in connection with obtaining financing are deferred and amortized on a straight-line basis for SCE and on a basis which approximates the effective interest rate method for EMG as interest expense over the term of the related debt. Under CPUC ratemaking procedures, debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt. SCE had unamortized losses on reacquired debt of $249 million and $268 million at December 31, 2011 and 2010, respectively, reflected in "Regulatory assets" in the long-term section of the consolidated balance sheets. Edison International had unamortized debt issuance costs of $134 million and $114 million at December 31, 2011 and 2010, respectively, reflected in "Other long-term assets" on the consolidated balance sheets. Amortization of deferred financing costs charged to interest expense was $49 million, $35 million and $31 million in 2011, 2010 and 2009, respectively.

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Revenue Recognition

Electric Utility Revenue

Electric utility revenue is recognized when 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 and FERC-authorized revenue requirements. CPUC rates are implemented upon final approval, and beginning in 2012 FERC rates are based on a forecasted revenue requirement, subject to refund and settlement procedures, and will be trued-up annually based on actual amounts.

CPUC rates decouple authorized revenue from the volume of electricity sales, so that SCE earns revenue equal to amounts authorized. Differences between amounts collected and authorized levels are either collected from or refunded to customers, and therefore, such differences do not impact operating revenue.

SCE remits to the California Department of Water Resources ("CDWR"), and does not recognize as revenue the amounts that SCE bills and collects from its customers for electric power purchased and sold by the CDWR to SCE's customers, as well as CDWR-bond-related costs and a portion of direct access exit fees. Power purchased by the CDWR for these long-term contracts are not considered a cost to SCE because SCE is acting as a limited agent to CDWR for these transactions. The amounts collected and remitted to CDWR were $1.1 billion, $1.2 billion, and $1.8 billion for the years ended December 31, 2011, 2010 and 2009, respectively. All power contracts that CDWR allocated to SCE had expired by the end of 2011. The bond-related charges and direct access exit fees continue until 2022.

Competitive Power Generation Revenue

Generally, revenues and related costs are recognized when electricity is generated, or services are provided, unless the transaction is accounted for as a derivative and does not qualify for the normal purchases and sales exception. EMG's subsidiaries enter into power and fuel hedging, optimization transactions and energy trading contracts, all subject to market conditions. One of EMG'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, EMG's subsidiaries generally act as the principal, take title to the commodities, and assume the risks and rewards of ownership. EMG's subsidiaries record the settlement of non-trading physical forward contracts on a gross basis. EMG 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, EMG'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 operating revenues in the accompanying consolidated statements of operations. Revenues under certain long-term power sales contracts are recognized based on the output delivered at the lower of the amount billable or the average rate over the contract term. The excess of the amounts billed over the portion recorded as revenues is reflected in deferred revenues on the consolidated balance sheets.

EMG accounts for grant income on the deferred method and, accordingly, will recognize operating revenues related to such income over the estimated useful life of the projects. In 2011, EMG received a total of $388 million of U.S. Treasury grants (cash grants, under the American Recovery and Reinvestment Act of 2009).

Power Purchase Agreements

Both SCE, generally as the purchaser, and EMG, generally as the seller, enter into power purchase agreements in the normal course of business. A power purchase agreement may be considered a variable interest in a variable interest entity. Under this classification, the power purchase agreement is evaluated to determine if SCE or EMG is the primary beneficiary in the variable interest entity, in which case, such entity would be consolidated. None of SCE's or EMG's power purchase agreements resulted in consolidation of a variable interest entity at December 31, 2011. See Note 3 for further discussion of power purchase agreements that are considered variable interests.

A power purchase agreement may also contain a lease for accounting purposes. This generally occurs when a power purchase agreement (signed or modified after June 30, 2003) designates a specific power plant in which the buyer purchases substantially all of the output and does not otherwise meet a fixed price per unit of output exception. SCE and EMG have a number of power purchase agreements that contain leases. EMG's revenue from these power sales agreements were $109 million, $81 million and $83 million in 2011, 2010 and 2009, respectively. SCE's recognition of lease expense conforms to the ratemaking treatment for SCE's recovery of the cost of electricity and are recorded in purchased power. These agreements are classified as operating leases as electricity is delivered at rates defined in power sales agreements. See Note 9 for further discussion of SCE's power purchase agreements, including agreements that are classified as capital leases for accounting purposes.

A power purchase agreement that does not contain a lease may be classified as a derivative subject to a normal purchase and sale exception, in which case the power purchase agreement is classified as an executory contract and accounted for on an accrual basis. 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 purchase and sale 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. These contracts are not eligible for the normal purchase and sale exception and are recorded as a derivative on the consolidated balance sheets at fair value. See Note 6 for further information on derivatives and hedging activities.

Power purchase agreements that do not meet the above classifications are accounted for on an accrual basis.

Derivative Instruments and Hedging Activities

Edison International records derivative instruments on its consolidated balance sheets as either assets or liabilities measured at fair value unless otherwise exempted from derivative treatment as normal purchases or sales. 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. Changes in the fair value of SCE's derivative instruments 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 expenses or earnings. SCE does not use hedge accounting for derivative transactions due to regulatory accounting treatment.

The accounting guidance for cash flow hedges provides that the effective portion of gains or losses on derivative instruments designated and qualifying as cash flow hedges be reported as a component of other comprehensive income and be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The remaining gains or losses on the derivative instruments, if any, must be recognized currently in earnings.

Where Edison International's derivative instruments are subject to a master netting agreement and certain criteria are met, Edison International presents its derivative assets and liabilities on a net basis on its consolidated balance sheets. In addition, derivative positions are offset against margin and cash collateral deposits. The results of derivative activities are recorded as part of cash flows from operating activities on the consolidated statements of cash flows. See Note 6 for further information on derivative and hedging activities.

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 $101 million, $102 million and $102 million for the years ended December 31, 2011, 2010 and 2009, respectively. When SCE acts as an agent and when the tax is not required to be remitted as not having been collected from the customer, the taxes are accounted for on a net basis. Amounts billed to and collected from customers for these taxes are remitted to the taxing authorities and are not recognized as electric utility revenue.

Stock-Based Compensation

Stock options, performance shares, deferred stock units and restricted stock units have been granted under Edison International's long-term incentive compensation programs. Generally, Edison International does not issue new common stock for settlement of equity awards. Rather, a third party is used to purchase shares from the market and delivery 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 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. Edison International recognizes stock-based compensation expense on a straight-line basis over the requisite service period. Edison International recognizes stock-based compensation expense for awards granted to retirement-eligible participants 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.

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Dividend Restrictions

The CPUC regulates SCE's capital structure which limits the dividends it may pay Edison International. In SCE's most recent cost of capital proceeding, the CPUC set 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 48% authorized level on a 13-month weighted average basis. At December 31, 2011, SCE's 13-month weighted-average common equity component of total capitalization was 50.4% resulting in the capacity to pay $436 million in additional dividends.

Earnings Per Share

Edison International computes earnings per share ("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. EPS attributable to Edison International common shareholders was computed as follows:

(in millions)	Years ended December 31, 2011	2010	2009
Basic earnings per share – continuing operations:			
Income from continuing operations attributable to common shareholders, net of tax	$(34)	$1,252	$856
Participating securities dividends	—	(5)	(6)
Income from continuing operations available to common shareholders	$(34)	$1,247	$850
Weighted average common shares outstanding	326	326	326
Basic earnings per share – continuing operations	$(0.10)	$3.83	$2.61
Diluted earnings per share – continuing operations:			
Income from continuing operations available to common shareholders	$(34)	$1,247	$850
Income impact of assumed conversions	— [1]	5	1
Income from continuing operations available to common shareholders and assumed conversions	$(34)	$1,252	$851
Weighted average common shares outstanding	326	326	326
Incremental shares from assumed conversions	— [1]	3 [2]	1 [2]
Adjusted weighted average shares – diluted	326	329	327
Diluted earnings per share – continuing operations	$(0.10)	$3.81	$2.60

1 Due to a loss for the period, there are no incremental shares in the computation because such shares would be considered antidilutive.

2 Stock-based compensation awards to purchase 5,981,090, and 8,547,090 shares of common stock for the years ended December 31, 2010 and 2009, respectively, were outstanding, but 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 during the respective periods and, therefore, the effect would have been antidilutive.

Income Taxes

Edison International estimates its income taxes for each jurisdiction in which it operates. This involves estimating current period tax expense along 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 sheets. Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Investment tax credits are deferred and amortized to income tax expense over the lives of the properties or the term of the power purchase agreement of the respective project while production tax credits are recognized in income tax expense in the period in which they are earned. EMG's investments in wind-powered electric generation projects qualify for federal production tax credits. Such credits are allowable for

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production during the 10-year period after a qualifying wind energy facility is placed into service. Certain of EMG's wind projects also qualify for state tax credits, which are accounted for similarly to federal production tax credits. Interest income, interest expense and penalties associated with income taxes are reflected in "Income tax expense" on the consolidated statements of income.

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. Pursuant to 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.

Related Party Transactions

Four EMG 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. Sales by these partnerships to SCE under these agreements amounted to $277 million, $367 million and $366 million in 2011, 2010 and 2009, respectively.

An indirect wholly owned affiliate of EMG has entered into operation and maintenance agreements with partnerships in which EMG has a 50% or less ownership interest. EMG recorded power generation revenue under these agreements of $23 million, $23 million and $26 million in 2011, 2010 and 2009, respectively. EMG's accounts receivable with this affiliate totaled $3 million and $5 million at December 31, 2011 and 2010, respectively.

New Accounting Guidance

Accounting Guidance Adopted in 2011

Revenue-Multiple-Deliverables

In October 2009, the Financial Accounting Standards Board ("FASB") issued amended guidance for identifying separate deliverables in a revenue-generating transaction where multiple deliverables exist, and provides guidance for allocating and recognizing revenues based on those separate deliverables. This update also requires additional disclosure related to the significant assumptions used to determine the revenue recognition of the separate deliverables. This guidance is required to be applied prospectively to new or significantly modified revenue arrangements. Edison International adopted this guidance effective January 1, 2011. The adoption of this accounting standards update did not have a material impact on Edison International's consolidated income statements, financial position or cash flows.

Fair Value Measurements and Disclosures

The FASB issued an accounting standards update modifying the disclosure requirements related to fair value measurements. Under these requirements, purchases and settlements for Level 3 fair value measurements are presented on a gross basis, rather than net. Edison International adopted this guidance effective January 1, 2011.

Accounting Guidance Not Adopted in 2011

Fair Value Measurement

In May 2011, the FASB issued an accounting standards update modifying the fair value measurement and disclosure guidance. This guidance prohibits grouping of financial instruments for purposes of fair value measurement and requires the value be based on the individual security. This amendment also results in new disclosures primarily related to Level 3 measurements including quantitative disclosure about unobservable inputs and assumptions, a description of the valuation processes and a narrative description of the sensitivity of the fair value to changes in unobservable inputs. Edison International will adopt this guidance in the first quarter of 2012. The adoption of this accounting standards update is not expected to have a material impact on Edison International's consolidated financial position.

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Presentation of Comprehensive Income

In June 2011 and December 2011, the FASB issued an accounting standards update on the presentation of comprehensive income. An entity can elect to present items of net income and other comprehensive income in one continuous statement, referred to as the statement of comprehensive income, or in two separate but consecutive statements. Edison International will adopt this guidance in the first quarter of 2012. Edison International currently presents the statement of comprehensive income immediately following the statement of income and will continue to do so. The adoption of this accounting standards update will not change the items that constitute net income and other comprehensive income.

Offsetting Assets and Liabilities

In December 2011, the FASB issued an accounting standards update modifying the disclosure requirements about the nature of an entity's rights of offsetting assets and liabilities in the statement of financial position under master netting agreements and related arrangements associated with financial and derivative instruments. The guidance requires increased disclosure of the gross and net recognized assets and liabilities, collateral positions and narrative descriptions of setoff rights. Edison International will adopt this guidance effective January 1, 2013. Edison International does not expect the adoption of this standard to have a material impact on Edison International's consolidated statements of income, financial position or cash flows.

Note 2. Property, Plant and Equipment

Utility Property, Plant and Equipment

Utility property, plant and equipment included on the consolidated balance sheets is composed of the following:

	December 31,	
(in millions)	2011	2010
Transmission	$6,109	$5,811
Distribution	15,938	14,878
Generation	4,063	3,371
General plant and other	3,951	3,377
Accumulated depreciation	(6,894)	(6,319)
	23,167	21,118
Construction work in progress	3,922	3,291
Nuclear fuel, at amortized cost	480	369
Total utility property, plant and equipment	$27,569	$24,778

Capitalized Software Costs

SCE capitalizes costs incurred during the application development stage of internal use software projects to property, plant, and equipment. SCE amortizes capitalized software costs ratably over the expected lives of the software, ranging from 5 to 15 years and commencing upon operational use. At December 31, 2011 and 2010, capitalized software costs were $1.4 billion and $1.1 billion and accumulated amortization was $491 million and $393 million, respectively. Amortization expense for capitalized software was $156 million, $129 million and $88 million in 2011, 2010 and 2009, respectively. At December 31, 2011, amortization expense is estimated to be approximately $174 million annually for 2012 through 2016.

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 these projects is reflected in the consolidated balance sheets and included in the above table. SCE's proportionate share of expenses for each project is reflected in the consolidated statements of income. All of the investments in the Mohave generating station and a portion of the investments in San Onofre and Palo Verde generating stations are included in regulatory assets on the consolidated balance sheets—see Note 14.

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The following is SCE's investment in each project as of December 31, 2011:

(in millions)	Plant in Service	Construction Work in Progress	Accumulated Depreciation	Nuclear Fuel (at amortized cost)	Net Book Value	Ownership Interest
Transmission systems:						
Eldorado	$71	$4	$13	$—	$62	60%
Pacific Intertie	189	2	68	—	123	50%
Generating stations:						
Four Corners Units 4 and 5 (coal)	589	17	519	—	87	48%
Mohave (coal)	327	24	287	—	64	56%
Palo Verde (nuclear)	1,803	54	1,465	138	530	16%
San Onofre (nuclear)	5,198	370	4,111	342	1,799	78%
Total	$8,177	$471	$6,463	$480	$2,665	

In addition to the projects above, SCE has ownership interests in jointly owned power poles with other companies.

On November 8, 2010, SCE entered into an agreement to sell its ownership interest in Units 4 and 5 of the Four Corners coal-fired electric generating facility to the operator of the facility, Arizona Public Service Company. The sale price is $294 million, subject to certain adjustments. The closing of the sale is contingent upon the receipt of regulatory approvals and other specified closing conditions and is estimated to occur in the second half of 2012. Any gain on sale will be for the benefit of SCE's customers and, therefore, will not affect SCE's earnings.

Competitive Power Generation and Other Property, Plant and Equipment

Competitive power generation and other property included on the consolidated balance sheets was composed of the plant and related facilities of EMG:

	December 31,	
(in millions)	2011	2010
Building, plant and equipment	$4,708	$4,572
Emission allowances	672	1,305
Leasehold improvements	4	177
Furniture and equipment	130	97
Land (including easements)	64	84
Construction work in progress[1]	377	1,036
	5,955	7,271
Accumulated depreciation	(1,408)	(1,865)
Competitive power generation and other property – net	$4,547	$5,406

1 Construction work in progress consisted of $357 million and $888 million at December 31, 2011 and 2010, respectively, for new gas and wind projects under construction.

EMG recorded $1.7 billion of impairment charges in 2011. For additional information on these charges, see Note 16.

The power sales agreements of certain wind projects are classified as operating leases. The carrying amount and related accumulated depreciation of the property of these wind projects totaled $1.6 billion and $203 million, respectively, at December 31, 2011.

Note 3. Variable Interest Entities

Effective January 1, 2010, Edison International adopted the FASB's new guidance regarding VIEs. A VIE is defined as a legal entity whose equity owners do not have sufficient equity at risk, or, as a group, the holders of the equity investment at risk lack any of the following three characteristics: decision-making rights, the obligation to absorb losses, or the right to receive the expected residual returns of the entity. The primary beneficiary is identified as the variable interest holder that has both

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the power to direct the activities of the VIE that most significantly impact the entity's economic performance and the obligation to absorb losses or the right to receive benefits from the entity that could potentially be significant to the VIE. The primary beneficiary is required to consolidate the VIE. Commercial and operating activities are generally the factors that most significantly impact the economic performance of VIEs in which Edison International has a variable interest. Commercial and operating activities include construction, operation and maintenance, fuel procurement, dispatch and compliance with regulatory and contractual requirements.

Description of Use of Variable Interest Entities

EMG and its subsidiaries and affiliates have used VIEs as part of joint development agreements and constructing or acquiring full or partial interests in power generation facilities and ancillary facilities, referred to by EMG as a project. EMG's subsidiaries and affiliates have financed the development and construction or acquisition of its projects by capital contributions from EMG 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 secured by project specific assets and structured as non-recourse to EMG, with several exceptions, including EMG's guarantee of the Powerton and Joliet leases as part of a refinancing of indebtedness incurred by its project subsidiary to purchase the Midwest Generation plants.

Categories of Variable Interest Entities

Projects or Entities that are Consolidated

At December 31, 2011 and 2010, EMG consolidated 13 and 14 projects, respectively, with a total generating capacity of 570 MW and 580 MW, respectively, that have minority interests held by others. In April 2011, EMG sold its 75% ownership interest in a Minnesota wind project.

The following table presents summarized financial information of the projects that were consolidated by EMG:

(in millions)	December 31, 2011	December 31, 2010
Current assets	$36	$26
Net property, plant and equipment	675	739
Other long-term assets	5	6
Total assets	$716	$771
Current liabilities	$28	$25
Long-term debt net of current portion	57	71
Deferred revenues	69	71
Other long-term liabilities	22	21
Total liabilities	$176	$188
Noncontrolling interests	$2	$4

Assets serving as collateral for the debt obligations had a carrying value of $136 million and $163 million at December 31, 2011 and 2010, respectively, and primarily consist of property, plant and equipment. Effective January 1, 2010, EMG prospectively consolidated the Ambit project (a 50% interest in American Bituminous Power Partners, L.P.) and deconsolidated the Elkhorn Ridge and San Juan Mesa wind projects.

During 2011, EMG purchased the remaining interests in Pinnacle Wind Force, LLC and Broken Bow I, LLC and all assets of the Crofton Bluffs project. During 2010, EMG purchased a noncontrolling interest in Laredo Ridge. All these projects are now 100% owned by EMG. The purchases of the noncontrolling interest were accounted for as equity transactions between controlling and noncontrolling interest holders.

Capistrano Wind Equity Capital - 2012

As part of its plan to obtain third-party equity capital to finance the development of a portion of EMG's wind portfolio, on February 13, 2012, Edison Mission Wind sold its indirect equity interests in the Cedro Hill wind project (150 MW in Texas), the Mountain Wind Power I project (61 MW in Wyoming) and the Mountain Wind Power II project (80 MW in Wyoming) to a new venture, Capistrano Wind Partners. Outside investors provided $238 million of the funding. Capistrano Wind Partners also agreed to acquire the Broken Bow I wind project (80 MW in Nebraska) and the Crofton Bluffs wind project (40 MW in Nebraska) for consideration expected to include $141 million from the same outside investors upon the satisfaction of

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specified conditions, including commencement of commercial operation and completion of project debt financing. The proceeds from outside investors, net of costs on the projects to be completed, are expected to be distributed to EMG and available for general corporate purposes.

An indirect subsidiary of EME, Edison Mission Wind, and EME's parent company, Mission Energy Holding Company (MEHC), own 100% of the Class A equity interests in Capistrano Wind Partners, and the Class B preferred equity interests are held by outside investors. Under the terms of the formation documents, preferred equity interests receive 100% of the cash available for distribution, up to a scheduled amount to target a return and thereafter cash distributions are shared. Cash available for distribution includes 90% of the tax benefits realized by MEHC and contributed to Capistrano Wind Partners.

Edison Mission Wind retains indirect beneficial ownership of the common equity in the projects, net of a $4 million preferred investment made by MEHC, and retains responsibilities for managing the operations of Capistrano Wind Holdings and its projects, and accordingly, EMG will continue to consolidate these projects. The amount contributed by the third-party interests will be reflected as a noncontrolling interest in the consolidated financial statements. Edison Mission Wind plans to distribute to EMG the amounts received from the sale of the projects, net of costs on the projects to be completed, which will then be available to EMG for general corporate purposes.

Variable Interest in VIEs that are not Consolidated

Power Purchase Contracts

SCE has 16 power purchase agreements ("PPAs") that have variable interests in VIEs, including 6 tolling agreements through which SCE provides the natural gas to fuel the plants and 10 contracts with qualifying facilities ("QFs") (including the Big 4 projects) that contain variable pricing provisions based on the price of natural gas. SCE has concluded that it is not the primary beneficiary of these VIEs since it does not control the commercial and operating activities of these entities. In general, because payments for capacity are the primary source of income, the most significant economic activity for SCE's VIEs is the operation and maintenance of the power plants.

As of the balance sheet date, the carrying amount of assets and liabilities in SCE's consolidated balance sheet that relate to its involvement with VIEs result from amounts due under the PPAs or the fair value of those derivative contracts. Under these contracts, SCE recovers the costs incurred through demonstration of compliance with its CPUC-approved long-term power procurement plans. SCE has no residual interest in the entities and has not provided or guaranteed any debt or equity support, liquidity arrangements, performance guarantees or other commitments associated with these contracts other than the purchase commitments described in Note 9. As a result, there is no significant potential exposure to loss as a result of SCE's involvement with these VIEs. The aggregate capacity dedicated to SCE for these VIE projects was 3,820 MW at December 31, 2011 and the amounts that SCE paid to these projects were $477 million and $534 million for the years ended December 31, 2011 and 2010, respectively. These amounts are recoverable in customer rates.

Equity Interests

EMG accounts for the majority of its investments in domestic gas and wind energy projects in which it has less than a 100% ownership interest, and does not have both the right to direct the commercial and operating activities and the obligation to absorb losses or receive benefits from the VIEs, under the equity method. As of December 31, 2011 and 2010, EMG had significant variable interests in five natural gas projects that are not consolidated, consisting of the Big 4 projects and the Sunrise project. A subsidiary of EMG operates three of the four Big 4 projects and the Sunrise project and EMG's partner provides the fuel management services for the Big 4 projects. In addition, the executive director of these gas projects is provided by EMG's partner. Commercial and operating activities of these gas projects are jointly controlled by a management committee of each VIE. Accordingly, EMG accounts for its variable interests in these projects under the equity method.

At December 31, 2011, EMG also accounted for its interest in the Community Wind North wind project, which achieved commercial operation on May 28, 2011, under the equity method. The commercial and operating activities of this entity are jointly directed by representatives of each partner. Thus EMG is not the primary beneficiary of this project.

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The following table presents the carrying amount of EMG's investments in unconsolidated VIEs and the maximum exposure to loss for each investment:

	December 31, 2011	
(in millions)	Investment	Maximum Exposure
Natural gas-fired projects	$315	$315
Wind projects	208	208

EMG's exposure to loss in its VIEs accounted for under the equity method is generally limited to its investment in these entities. At December 31, 2011 and 2010, outstanding debt for projects that are not consolidated consisted of long-term debt that was secured by a pledge of project entity assets, but does not provide for recourse to EMG. At December 31, 2011, such outstanding indebtedness was $62 million, of which $16 million was proportionate to EMG's ownership in the project. At December 31, 2010, such outstanding indebtedness was $116 million, of which $41 million was proportionate to EMG's ownership interest in the projects.

EMG has also invested in affordable housing projects utilizing partnership or limited liability companies. With a few exceptions, an unrelated general partner or managing member exercises operating control of these projects. At December 31, 2011, projects that EMG has accounted for under the equity method had indebtedness of approximately $1.2 billion, of which approximately $318 million is proportionate to its ownership interest in these projects. At December 31, 2010, projects that EMG has accounted for under the equity method had indebtedness of approximately $1.3 billion, of which approximately $451 million is proportionate to its ownership interest in these projects. Substantially all of this debt is nonrecourse to Edison Capital.

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

	Years Ended December 31,		
(in millions)	2011	2010	2009
Revenues	$971	$1,043	$581
Expenses	839	934	506
Net income	$132	$109	$75

	December 31,	
(in millions)	2011	2010
Current assets	$337	$352
Noncurrent assets	2,098	2,437
Total assets	$2,435	$2,789
Current liabilities	$144	$227
Noncurrent liabilities	1,230	1,312
Equity	1,061	1,250
Total liabilities and equity	$2,435	$2,789

The difference between the carrying value of these equity investments and the underlying equity in the net assets was $10 million at December 31, 2011. The difference is being amortized over the life of the projects. The majority of noncurrent liabilities are composed of project financing arrangements that are nonrecourse to EMG. The undistributed earnings of equity method investments were $19 million and $28 million at December 31, 2011 and 2010, respectively.

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The following table presents, as of December 31, 2011, the investments in unconsolidated affiliates accounted for by the equity method that represent at least 5% of EMG's loss before tax, excluding asset impairment charges, or in which EMG has an investment balance greater than $50 million:

Unconsolidated Affiliates	Location	Investment at December 31, 2011 (in millions)	Ownership Interest at December 31, 2011	Operating Status
San Juan Mesa	Elida, NM	$84	75%	Operating wind-powered facility
Elkhorn Ridge	Bloomfield, NE	81	67%	Operating wind-powered facility
Sunrise	Fellows, CA	173	50%	Operating gas-fired facility
Sycamore	Bakersfield, CA	34	50%	Operating cogeneration facility
Kern River	Bakersfield, CA	21	50%	Operating cogeneration facility
Watson	Carson, CA	42	49%	Operating cogeneration facility

The following table presents summarized financial information of the investments in unconsolidated affiliates:

	December 31,	
(in millions)	2011	2010
Investments in Unconsolidated Affiliates		
Equity investments	$517	$550
Cost investments	8	9
Total	$525	$559

Note 4. Fair Value Measurements

Recurring Fair Value Measurements

Fair value is defined 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. Fair value of an asset or liability should consider assumptions that market participants would use in pricing the asset or liability, including assumptions about nonperformance risk.

Edison International categorizes financial assets and liabilities into a fair value hierarchy based on valuation inputs used to determine 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).

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The following table sets forth assets and liabilities that were accounted for at fair value by level within the fair value hierarchy:

	As of December 31, 2011				
(in millions)	Level 1	Level 2	Level 3	Netting and Collateral[1]	Total
Assets at Fair Value					
Money market funds[2]	$1,321	$—	$—	$—	$1,321
Derivative contracts:					
Electricity	—	66	218	(62)	222
Natural gas	4	5	—	(7)	2
Fuel oil	4	—	—	(4)	—
Tolling	—	—	10	—	10
Subtotal of commodity contracts	8	71	228	(73)	234
Long-term disability plan	8	—	—	—	8
Nuclear decommissioning trusts:					
Stocks[3]	1,899	—	—	—	1,899
Municipal bonds	—	756	—	—	756
U.S. government and agency securities	433	147	—	—	580
Corporate bonds[4]	—	317	—	—	317
Short-term investments, primarily cash equivalents[5]	—	15	—	—	15
Subtotal of nuclear decommissioning trusts	2,332	1,235	—	—	3,567
Total assets[6]	3,669	1,306	228	(73)	5,130
Liabilities at Fair Value					
Derivative contracts:					
Electricity	—	13	77	(21)	69
Natural gas	—	234	23	(52)	205
Tolling	—	—	451	—	451
Subtotal of commodity contracts	—	247	551	(73)	725
Interest rate contracts	—	90	—	—	90
Total liabilities	—	337	551	(73)	815
Net assets (liabilities)	$3,669	$969	$(323)	$—	$4,315

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(in millions)	As of December 31, 2010 Level 1	Level 2	Level 3	Netting and Collateral[1]	Total
Assets at Fair Value					
Money market funds[2]	$1,100	$—	$—	$—	$1,100
Derivative contracts:					
Electricity	—	70	363	(61)	372
Natural gas	1	69	11	(1)	80
Fuel oil	8	—	—	(8)	—
Tolling	—	—	118	—	118
Subtotal of commodity contracts	9	139	492	(70)	570
Long-term disability plan	9	—	—	—	9
Nuclear decommissioning trusts:					
Stocks[3]	2,029	—	—	—	2,029
Municipal bonds	—	790	—	—	790
Corporate bonds[4]	—	346	—	—	346
U.S. government and agency securities	215	73	—	—	288
Short-term investments, primarily cash equivalents[5]	1	31	—	—	32
Subtotal of nuclear decommissioning trusts	2,245	1,240	—	—	3,485
Total assets[6]	3,363	1,379	492	(70)	5,164
Liabilities at Fair Value					
Derivative contracts:					
Electricity	—	13	40	(21)	32
Natural gas	—	286	11	(4)	293
Tolling	—	—	344	—	344
Coal	—	1	—	(1)	—
Subtotal of commodity contracts	—	300	395	(26)	669
Interest rate contracts	—	16	—	—	16
Total liabilities	—	316	395	(26)	685
Net assets (liabilities)	$3,363	$1,063	$97	$(44)	$4,479

1 Represents the netting of assets and liabilities under master netting agreements and cash collateral across the levels of the fair value hierarchy. Netting among positions classified within the same level is included in that level.

2 Money market funds are included in cash and cash equivalents and restricted cash and cash equivalents on Edison International's consolidated balance sheets.

3 Approximately 70% and 67% of the equity investments were located in the United States at December 31, 2011 and 2010, respectively.

4 At December 31, 2011 and 2010, corporate bonds were diversified and included collateralized mortgage obligations and other asset backed securities of $22 million and $27 million, respectively.

5 Excludes net receivables of $25 million and net liabilities of $5 million at December 31, 2011 and 2010, respectively, of interest and dividend receivables and receivables related to pending securities sales and payables related to pending securities purchases.

6 Excludes $31 million at both December 31, 2011 and 2010, of cash surrender value of life insurance investments for deferred compensation.

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The following table sets forth a summary of changes in the fair value of Level 3 assets and liabilities:

(in millions)	December 31, 2011	2010
Fair value, net assets at beginning of period	$97	$62
Total realized/unrealized gains (losses):		
Included in earnings[1]	(19)	64
Included in regulatory assets and liabilities[2]	(458)[3]	58
Included in accumulated other comprehensive income	1	2
Purchases	81	66
Settlements	(23)	(166)
Transfers in or out of Level 3	(2)	11
Fair value, net assets (liabilities) at end of period	$(323)	$97
Change during the period in unrealized gains (losses) related to assets and liabilities held at the end of the period[4]	$(644)	$143

1 Reported in "Competitive power generation" revenue on Edison International's consolidated statements of income.

2 Due to regulatory mechanisms, SCE's realized and unrealized gains and losses are recorded as regulatory assets and liabilities.

3 Includes the elimination of the fair value of derivatives with SCE's consolidated affiliates.

4 Amounts reported in "Competitive power generation" revenue on Edison International's consolidated statements of income were $16 million and $13 million for the years ended December 31, 2011 and 2010, respectively. The remainder of the unrealized losses relate to SCE. See 2 above.

Edison International determines the fair value for transfers in and transfers out of each level at the end of each reporting period. There were no significant transfers between levels during 2011 and 2010.

Valuation Techniques Used to Determine Fair Value

Level 1

Includes financial assets and liabilities where fair value is determined using unadjusted quoted prices in active markets that are available at the measurement date for identical assets and liabilities. Financial assets and liabilities classified as Level 1 include exchange-traded equity securities, exchange traded derivatives, U.S. treasury securities and money market funds.

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 derivative instrument. Financial assets and liabilities utilizing Level 2 inputs include fixed-income securities and over-the-counter derivatives.

Derivative contracts that are over-the-counter traded are valued using pricing models to determine the net present value of estimated future cash flows and are generally classified as Level 2. Inputs to the pricing models include forward published or posted clearing prices from exchanges (New York Mercantile Exchange and Intercontinental Exchange) for similar instruments and discount rates. A primary source that best represents traded activity for each market is used 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 believed to provide the most liquid market for the commodity. Broker quotes are incorporated when corroborated with other information which may include a combination of prices from exchanges, other brokers and comparison to executed trades.

Level 3

Includes financial assets and liabilities where fair value is determined using techniques that require significant unobservable inputs. Over-the-counter options, bilateral contracts, capacity contracts, QF contracts, derivative contracts that trade infrequently (such as congestion revenue rights ("CRRs") in the California market), long-term power agreements, and

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derivative contracts with counterparties that have significant nonperformance risks are generally valued using pricing models that incorporate unobservable inputs and are classified as Level 3. Assumptions are made in order to value derivative contracts in which observable inputs are not available. 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.

For derivative contracts that trade infrequently (illiquid financial transmission rights and CRRs), changes in fair value are based on models forecasting the value of those contracts. The models' inputs are reviewed and the fair value is adjusted when it is concluded that a change in inputs would result in a new valuation that better reflects the fair value of those derivative contracts. For illiquid long-term power agreements, fair value is based upon the 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. The fair value of the majority of SCE's derivatives that are classified as Level 3 is determined using uncorroborated non-binding broker quotes 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.

Nonperformance Risk

The fair value of the derivative assets and liabilities are adjusted for nonperformance risk. To assess nonperformance risks, SCE considers the probability of and the estimated loss incurred if a party to the transaction were to default. SCE also considers collateral, netting agreements, guarantees and other forms of credit support when assessing nonperformance. EMG 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 nonperformance. The nonperformance risk adjustment represented an insignificant amount at both December 31, 2011 and 2010.

Nuclear Decommissioning Trusts

SCE's 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.

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. Except for Level 3 investments, valuation is based on observable market inputs and assumptions used by market participants. With respect to equity and fixed income securities, the trustee obtains prices from third-party pricing services which SCE is able to independently corroborate as described below. A primary price source is identified by the trustee 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 or SCE's investment managers challenge an assigned price and determine that another price source is considered to be preferable. The trustee "scrubs" prices against defined parameters at established times throughout the day. Variances that do not meet the parameters are researched and resolved. Unpriced and stale priced securities, as well as any unusual variations in market price or overall market value are investigated. Price variance reports are reviewed on the basis of predetermined tolerances. Variances identified outside of tolerance are then researched and resolved. Parameters and predetermined tolerance thresholds are established by asset class based on past experience and an understanding of valuation process techniques. Questionable prices are reported to the vendor who provided the price and pricing specialists then follow-up with the vendors. If the prices are validated, the primary price source is used. If not, a secondary source price which has passed the applicable tolerance check is used. The trustee monitors and grades the performance of pricing vendors. SCE reviewed the process/procedures of both the pricing services and the trustee to gain an understanding of the inputs/assumptions and valuation techniques used to price each asset type/class and to reach a conclusion that their pricing controls are satisfactory. This consisted of SCE's review of their written detailed process/procedures and service organization control (SOC 1-formerly SAS 70) reports, as well as follow-up conversations based on our written questions. This assists SCE in determining if the valuations represent exit price fair value and that investments are appropriately classified in the fair value hierarchy. Additionally, SCE corroborates the fair values of securities by comparison

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to other market-based price sources obtained by SCE's investment managers. Differences outside established thresholds are followed-up with the trustee and resolved. The results of this process have demonstrated that vendor and trustee pricing controls are satisfactory. For each reporting period, SCE reviews the trustee determined fair value hierarchy and overrides the trustee level classification when appropriate. Due to its regulatory treatment, SCE's fair value transactions are recovered in rates.

Non-Recurring Fair Value Measurements

For a discussion on non-recurring fair value measurements, see Note 16.

Fair Value of Long-Term Debt Recorded at Carrying Value

The carrying value and fair value of long-term debt are:

	December 31, 2011		December 31, 2010	
(in millions)	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt, including current portion	$13,746	$14,264	$12,419	$12,360

Fair values of long-term debt are 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 of new issue prices and relevant credit information. The fair value of long-term debt is classified as Level 2.

The carrying value of trade receivables, payables and short-term debt approximates fair value.

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Note 5. Debt and Credit Agreements

Long-Term Debt

The following table summarizes long-term debt (rates and terms are as of December 31, 2011):

(in millions)	December 31, 2011	2010
First and refunding mortgage bonds:		
2014 – 2041 (3.875% to 6.05% and floating)	$7,375	$6,475
Pollution-control bonds:		
2028 – 2035 (2.875% to 5.0% and variable)	939	1,196
Bonds repurchased	(161)	(324)
Debentures and notes:		
2013 – 2053 (5.06% to 7.625%)	4,407	4,410
Wind project financings:		
Tapestry Wind, LLC		
Term Loan (LIBOR plus 2.5%)	214	—
Big Sky Wind, LLC		
Vendor financing loan due 2014 (LIBOR plus 3.5%)	211	190
Viento Funding II, Inc.		
Term Loan due 2020 (LIBOR plus 2.75%)	207	150
Walnut Creek Energy and WCEP Holdings, LLC		
Construction Loans due 2013 (LIBOR plus 2.25% ; LIBOR plus 4%)	187	—
Cedro Hill Wind, LLC		
Term Loan due 2025 (LIBOR plus 3.0%)	131	135
Laredo Ridge		
Term Loan due 2026 (LIBOR plus 2.75%)	74	—
High Lonesome Mesa, LLC		
Bonds Series 2010A and 2010B due 2017 (6.85%)	72	75
Other wind project financings	55	23
Other long-term debt	65	117
Long-term debt due within one year	(57)	(48)
Unamortized debt discount – net	(30)	(28)
Total	$13,689	$12,371

Long-term debt maturities for the next five years are: 2012 – $57 million; 2013 – $755 million; 2014 – $1.5 billion; 2015 – $372 million; and 2016 – $966 million.

Liens and Security Interests

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 certain pollution-control bonds issued by government agencies. SCE has a debt covenant that requires a debt to total capitalization ratio be met. At December 31, 2011, SCE was in compliance with this debt covenant.

In connection with Midwest Generation's financing activities, a first priority security interest was provided in substantially all the coal-fired generating plants owned by Midwest Generation and the assets relating to those plants, the receivables of EMMT directly related to Midwest Generation's hedging activities and the pledge of the intercompany notes from EME (approximately $1.3 billion at December 31, 2011). The net book value of assets pledged or mortgaged was $2.3 billion at December 31, 2011. In addition to these assets, Midwest Generation's membership interests and the capital stock of Edison Mission Midwest Holdings were pledged.

In connection with the wind financings, payment obligations are generally secured by pledges of its direct and indirect ownership interests in the projects, project agreements and reserve accounts, if applicable. In connection with the Big Sky

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turbine financing, the loan is secured by a leasehold mortgage on the project's real property assets, a pledge of all other collateral of the Big Sky wind project, as well as a cash reserve account into which one-third of distributable cash flow, if any, of the Big Sky wind project is to be deposited on a monthly basis. For further details regarding consolidated assets pledged as security for debt obligations, see Note 3—Variable Interest Entities.

EME Senior Notes

EME has $3.7 billion of senior notes due 2013 through 2027. 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.

Credit Agreements and Short-Term Debt

Edison International (parent) has a $1.4 billion revolving credit facility with various banks that terminates in February 2013. Edison International's (parent) short-term debt is generally used for liquidity purposes. At December 31, 2011, Edison International (parent)'s outstanding short-term debt was $10 million at a weighted-average interest rate of 0.66%. At December 31, 2010, the outstanding short-term debt was $19 million at a weighted-average interest rate of 0.63%.

SCE has two revolving credit facilities with various banks; a $2.4 billion five-year credit facility that matures in February 2013, and a $500 million three-year credit facility that matures in March 2013. Commercial paper issued under these credit facilities are generally used to finance fuel inventories, balancing accounts undercollections and general, temporary cash requirements including power purchase payments. At December 31, 2011, the outstanding commercial paper was $419 million at a weighted-average interest rate of 0.44%. At December 31, 2011, letters of credit issued under SCE's credit facilities aggregated $81 million and were scheduled to expire in twelve months or less.

At December 31, 2011, EMG's subsidiaries, EME and Midwest Generation, had credit facilities of $564 million and $500 million, respectively, maturing in June 2012. At December 31, 2011, EMG had no borrowings outstanding and $69 million of letters of credit outstanding under these credit facilities. Subsequent to the end of the fiscal year EME terminated its secured credit facility.

The following table summarizes the status of the credit facilities at December 31, 2011:

(in millions)	SCE	EMG	Edison International (parent)
Commitment	$2,894	$1,064	$1,426
Outstanding borrowings	(419)	—	(10)
Outstanding letters of credit	(81)	(69)	—
Amount available	$2,394	$995	$1,416

Letters of Credit

Letters of credit under EME's and its subsidiaries' credit facilities aggregated $177 million and were scheduled to expire as follows: $146 million in 2012, $3 million in 2013, $10 million in 2017, and $18 million in 2018. Standby letters of credit include $40 million issued in connection with the power purchase agreement with SCE, under the Walnut Creek credit facility. Certain letters of credit are subject to automatic annual renewal provisions.

Note 6. Derivative Instruments and Hedging Activities

Electric Utility

SCE uses derivative financial instruments to manage exposure to commodity price risk. SCE manages these risks in part by entering into forward commodity transactions, including options, swaps and futures. SCE 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.

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Commodity Price Risk

SCE is exposed to commodity price risk which represents the potential impact that can be caused by a change in the market value of a particular commodity. SCE's hedging program reduces customer exposure to variability in market prices related to SCE's power and gas activities. As part of this program, SCE enters into options, swaps, forwards, tolling arrangements and CRRs. These transactions are approved by the CPUC or executed in compliance with CPUC-approved procurement plans. SCE recovers its related hedging costs through the energy resource recovery account ("ERRA") balancing account, and as a result, exposure to commodity price risk is not expected to impact earnings, but may impact cash flows.

SCE's electricity price exposure arises from energy purchased from and sold to wholesale markets as a result of differences between SCE's load requirements and the amount of energy delivered from its generating facilities and power purchase agreements.

SCE's natural gas price exposure arises from natural gas purchased for the Mountainview power plant and peaker plants, QF contracts where pricing is based on a monthly natural gas index and power purchase agreements in which SCE has agreed to provide the natural gas needed for generation, referred to as tolling arrangements.

Notional Volumes of Derivative Instruments

The following table summarizes the notional volumes of derivatives used for hedging activities:

Commodity	Unit of Measure	Economic Hedges December 31, 2011	December 31, 2010
Electricity options, swaps and forwards	GWh	30,881	32,138
Natural gas options, swaps and forwards	Bcf	300	250
Congestion revenue rights	GWh	166,163	181,291
Tolling arrangements	GWh	104,154	114,599

Fair Value of Derivative Instruments

The following table summarizes the gross and net fair values of commodity derivative instruments at December 31, 2011:

	Derivative Assets			Derivative Liabilities[1]			
(in millions)	Short-Term	Long-Term	Subtotal	Short-Term	Long-Term	Subtotal	Net Liability
Non-trading activities							
Economic hedges	$86	$85	$171	$303	$856	$1,159	$988
Netting and collateral	(21)	(15)	(36)	(37)	(51)	(88)	(52)
Total	$65	$70	$135	$266	$805	$1,071	$936

1 Includes the fair value of derivatives with SCE's consolidated affiliates; however, in Edison International’s consolidated financial statements, the fair value of such derivatives is eliminated.

The following table summarizes the gross and net fair values of commodity derivative instruments at December 31, 2010:

	Derivative Assets			Derivative Liabilities			
(in millions)	Short-Term	Long-Term	Subtotal	Short-Term	Long-Term	Subtotal	Net Liability
Non-trading activities							
Economic hedges	$87	$367	$454	$216	$449	$665	$211
Netting and collateral	—	—	—	(4)	—	(4)	(4)
Total	$87	$367	$454	$212	$449	$661	$207

Income Statement Impact of Derivative Instruments

SCE recognizes realized gains and losses on derivative instruments as purchased power expense and expects that such gains or losses will be part of the purchase power costs recovered from customers. As a result, realized gains and losses are not reflected in earnings, but may temporarily affect cash flows. Due to expected future recovery from customers, unrealized

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gains and losses are recorded as regulatory assets and liabilities and therefore are also not reflected in earnings. The results of derivative activities and related regulatory offsets are recorded in cash flows from operating activities in the consolidated statements of cash flows

The following table summarizes the components of economic hedging activity:

	Years ended December 31,		
(in millions)	2011	2010	2009
Realized gains/(losses)	$(165)	$(156)	(344)
Unrealized gains/(losses)	(768)	36	470

Contingent Features/Credit Related Exposure

Certain derivative instruments and power procurement contracts under SCE's power and natural gas hedging activities contain collateral requirements. SCE has historically provided collateral in the form of cash and/or letters of credit for the benefit of counterparties. These requirements can vary depending upon the level of unsecured credit extended by counterparties, changes in market prices relative to contractual commitments and other factors.

Certain of these power contracts contain a provision that requires SCE to maintain an investment grade credit rating from each of the major credit rating agencies, referred to as a credit-risk-related contingent feature. If SCE's credit rating were to fall below investment grade, SCE may be required to pay the derivative liability or post additional collateral. The aggregate fair value of all derivative liabilities with these credit-risk-related contingent features was $216 million and $67 million as of December 31, 2011 and 2010, respectively, for which SCE has posted no collateral and $4 million of collateral to its counterparties for the respective periods. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2011, SCE would be required to post $36 million of collateral.

Counterparty Default Risk Exposure

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. Substantially all of the contracts that SCE has executed with counterparties are either entered into under SCE's procurement plan which has been pre-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.

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. To mitigate credit risk from counterparties, master netting agreements are used whenever possible and counterparties may be required to pledge collateral when deemed necessary.

Competitive Power Generation

EMG uses derivative instruments to reduce its exposure to market risks that arise from price fluctuations of electricity, capacity, fuel, emission allowances, transmission rights and interest rates. The derivative financial instruments vary in duration, ranging from a few days to several years, depending upon the instrument. To the extent that EMG does not use derivative instruments to hedge these market risks, the unhedged portions will be subject to the risks and benefits of spot market price movements.

Risk management positions may be designated as cash flow hedges or economic hedges, which are derivatives that are not designated as cash flow hedges. Economic hedges are accounted for at fair value on EMG's consolidated balance sheets as derivative assets or liabilities with offsetting changes recorded on the consolidated statements of operations. For derivative instruments that qualify for hedge accounting treatment, the fair value is recognized on EMG's consolidated balance sheets as derivative assets or liabilities with offsetting changes in fair value, to the extent effective, recognized in accumulated other comprehensive loss until reclassified into earnings when the related forecasted transaction occurs. The portion of a cash flow hedge that does not offset the change in the fair value of the transaction being hedged, which is commonly referred to as the ineffective portion, is immediately recognized in

earnings.
Derivative instruments that are utilized for trading purposes are measured at fair value and included on the consolidated

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balance sheets as derivative assets or liabilities, with offsetting changes recognized in operating revenues on the consolidated statements of operations.

The results of derivative activities are recorded in cash flows from operating activities on the consolidated statements of cash flows.

Where EMG's derivative instruments are subject to a master netting agreement and the criteria of authoritative guidance are met, EMG presents its derivative assets and liabilities on a net basis on its consolidated balance sheets.

Notional Volumes of Derivative Instruments

The following table summarizes the notional volumes of derivatives used for hedging and trading activities:

December 31, 2011

Commodity	Instrument	Classification	Unit of Measure	Hedging Activities Cash Flow Hedges	Economic Hedges	Trading Activities
Electricity	Forwards/Futures	Sales, net	GWh	8,320 [1]	425 [3]	—
Electricity	Forwards/Futures	Purchases, net	GWh	—	—	2,926
Electricity	Capacity	Sales, net	MW-Day (in thousands)	89 [2]	—	—
Electricity	Capacity	Purchases, net	MW-Day (in thousands)	—	—	184 [2]
Electricity	Congestion	Purchases, net	GWh	—	2,528 [4]	230,798 [4]
Natural gas	Forwards/Futures	Sales, net	bcf	—	—	0.2
Fuel oil	Forwards/Futures	Purchases, net	barrels	—	240,000	—

At December 31, 2011, EME had interest rate contracts with notional values totaling $644 million that converted floating rate LIBOR-based debt to fixed rates ranging from 0.79% to 4.29%. These contracts expire May 2013 through March 2026. In addition, EME had forward starting interest rate contracts with notional values totaling $506 million that will convert floating rate LIBOR-based debt to fixed rates of 3.5429% and 4.0025%. These contracts have effective dates of June 2013 and December 2021 and expire May 2023 and December 2029.

December 31, 2010

Commodity	Instrument	Classification	Unit of Measure	Hedging Activities Cash Flow Hedges	Economic Hedges	Trading Activities
Electricity	Forwards/Futures	Sales, net	GWh	16,391 [1]	—	—
Electricity	Forwards/Futures	Purchases, net	GWh	—	475 [3]	3,039
Electricity	Capacity	Sales, net	MW-Day (in thousands)	182 [2]	—	— [2]
Electricity	Capacity	Purchases, net	MW-Day (in thousands)	—	—	283
Electricity	Congestion	Purchases, net	GWh	—	1,007 [4]	175,669 [4]
Natural gas	Forwards/Futures	Purchases, net	bcf	—	—	3.7
Fuel oil	Forwards/Futures	Purchases, net	barrels	—	240,000	—
Coal	Forwards/Futures	Purchases, net	tons	—	—	15,000

1 EMG's hedge products include forward and futures contracts that qualify for hedge accounting. This category excludes power contracts for the coal plants which meet the normal purchases and sales exception and are accounted for on the accrual method.

2 EMG's hedge transactions for capacity result from bilateral trades. Capacity sold in the PJM Reliability Pricing Model (RPM) auction is not accounted for as a derivative.

3 These positions adjust financial and physical positions, or day-ahead and real-time positions, to reduce costs or increase gross margin. The net sales positions of these categories are primarily related to hedge transactions that are not designated as cash flow hedges.

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4 Congestion contracts include financial transmission rights, transmission congestion contracts or congestion revenue rights. These positions are similar to a swap, where the buyer is entitled to receive a stream of revenues (or charges) based on the hourly day-ahead price differences between two locations.

At December 31, 2010, EME had interest rate contracts with notional values totaling $328 million that converted floating rate LIBOR-based debt to fixed rates ranging from 3.175% to 4.29%. These contracts expire June 2016 through March 2026.

Included in trading activities in the preceding table, EME shows net the volume of energy trading activities that are physically settled. Gross purchases and sales totaled 3,332 GWh, 3,944 GWh and 3,791 GWh during 2011, 2010 and 2009, respectively.

Fair Value of Derivative Instruments

The following table summarizes the fair value of derivative instruments reflected on EMG's consolidated balance sheets:

December 31, 2011

	Derivative Assets			Derivative Liabilities			Net Assets
(in millions)	Short-term	Long-term	Subtotal	Short-term	Long-term	Subtotal	(Liabilities)
Non-trading activities							
Cash flow hedges							
Commodity contracts	$41	$1	$42	$2	$3	$5	$37
Interest rate contracts	—	—	—	—	90	90	(90)
Economic hedges	31	1	32	26	1	27	5
Trading activities	276	142	418	232	79	311	107
	348	144	492	260	173	433	59
Netting and collateral received[1]	(308)	(85)	(393)	(259)	(83)	(342)	(51)
Total	$40	$59	$99	$1	$90	$91	$8

December 31, 2010

	Derivative Assets			Derivative Liabilities			Net Assets
(in millions)	Short-term	Long-term	Subtotal	Short-term	Long-term	Subtotal	(Liabilities)
Non-trading activities							
Cash flow hedges							
Commodity contracts	$54	$2	$56	$10	$9	$19	$37
Interest rate contracts	—	—	—	—	16	16	(16)
Economic hedges	77	2	79	71	—	71	8
Trading activities	184	103	287	148	29	177	110
	315	107	422	229	54	283	139
Netting and collateral received[1]	(269)	(37)	(306)	(223)	(35)	(258)	(48)
Total	$46	$70	$116	$6	$19	$25	$91

1 Netting of derivative receivables and derivative payables and the related cash collateral received and paid is permitted when a legally enforceable master netting agreement exists with a derivative counterparty.

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Income Statement Impact of Derivative Instruments

The following table provides the cash flow hedge activity as part of accumulated other comprehensive loss:

	Cash Flow Hedge Activity[1]				
	2011		2010		
(in millions)	Commodity Contracts	Interest Rate Contracts	Commodity Contracts	Interest Rate Contracts	Income Statement Location
Beginning of period derivative gains (losses)	$43	$(16)	$177	$(2)	
Effective portion of changes in fair value	55	(74)	106	(14)	
Reclassification to earnings	(63)	—	(240)	—	Competitive power generation revenue
End of period derivative gains (losses)	$35	$(90)	$43	$(16)	

1 Unrealized derivative gains (losses) are before income taxes. The after-tax amounts recorded in accumulated other comprehensive loss at December 31, 2011 and 2010 for commodity and interest rate contracts were $21 million and $(55) million and $26 million and $(10) million, respectively.

For additional information, see Note 11.

EMG recorded net gains (losses) of $11 million, $(4) million and $24 million in 2011, 2010 and 2009, respectively, in operating revenues on the consolidated statements of operations representing the amount of cash flow hedge ineffectiveness.

The effect of realized and unrealized gains (losses) from derivative instruments used for economic hedging and trading purposes on the consolidated statements of operations is presented below:

		December 31,	
(in millions)	Income Statement Location	2011	2010
Economic hedges	Competitive power generation revenue	$21	$8
	Fuel	3	2
Trading activities	Competitive power generation revenue	76	114

Energy Trading Derivative Instruments

The change in the fair value of energy trading derivative instruments was as follows:

	Years ended December 31,	
(in millions)	2011	2010
Fair value of trading contracts at beginning of year	$110	$122
Net gains from energy trading activities	76	114
Amount realized from energy trading activities	(84)	(131)
Other changes in fair value	5	5
Fair value of trading contracts at end of year	$107	$110

Contingent Features

Certain derivative instruments contain margin and collateral deposit requirements. Since EME's and its subsidiaries' credit ratings are below investment grade, EME and its subsidiaries have provided collateral in the form of cash and letters of credit for the benefit of derivative counterparties. Future increases in power prices could expose EME, Midwest Generation or EMMT to additional collateral postings. Furthermore, EMMT has hedge contracts that do not require margin, but contain the right of each party to request additional credit support in the form of adequate assurance of performance in the case of adverse development affecting the other party.

Commodity Price Risk Management

EMG's merchant operations are exposed to commodity price risk, which reflects the potential impact of a change in the

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market value of a particular commodity. Commodity price risks are actively monitored, with oversight provided by a risk management committee, to ensure compliance with EMG's risk management policies. EMG uses estimates of the variability in gross margin to help identify, measure, monitor and control its overall market risk exposure and earnings volatility with respect to hedge positions at the coal plants and the merchant wind projects, and uses "value at risk" metrics to help identify, measure, monitor and control its overall risk exposure in respect to its trading positions. These measures allow management to aggregate overall commodity risk, compare risk on a consistent basis and identify changes in risk factors. Value at risk measures the possible loss, and variability in gross margin 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, EMG 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 volumetric exposure limits. When appropriate, EMG manages the spread between the electric prices and fuel prices, and uses forward contracts, swaps, futures, or options contracts to achieve those objectives.

Interest Rate Risk Management

Interest rate changes affect the cost of capital needed to operate EMG's 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 EMG's project financings.

Credit Risk

In conducting EMG's hedging and trading activities, EMG enters into transactions with 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, EMG would be exposed to the risk of possible loss associated with market price changes occurring since the original contract was executed if the nonperforming counterparty were unable to pay the resulting damages owed to EMG. Further, EMG would be exposed to the risk of non-payment of accounts receivable accrued for products delivered prior to the time a counterparty defaulted.

Credit risk is measured as the loss that EMG would expect to incur if a counterparty failed to perform pursuant to the terms of its contractual obligations. To manage credit risk, EMG evaluates the risk of potential defaults by counterparties. To mitigate credit risk from counterparties, master netting agreements are used whenever possible and counterparties may be required to pledge collateral when deemed necessary.

The majority of EMG's consolidated wind projects and unconsolidated affiliates that own power plants sell power under power purchase agreements. Generally, each project or plant sells its output to one counterparty. A default by the counterparty, including a default as a result of a bankruptcy, would likely have a material adverse effect on the operations of the project or plant.

The majority of the coal for the coal plants is purchased from suppliers under contracts which may be for multiple years. None of the coal suppliers to the coal plants have investment grade credit ratings and, accordingly, EMG may have limited recourse to collect damages in the event of default by a supplier.

The coal plants sell electric power generally into the PJM market by participating in PJM's capacity and energy markets or transacting in capacity and energy on a bilateral basis. Sales into PJM accounted for approximately 69%, 66% and 48% of EMG's consolidated operating revenues for the years ended December 31, 2011, 2010 and 2009, respectively. Moody's Investors Service, Inc. (Moody's) rates PJM's debt Aa3. PJM, a regional transmission organization (RTO) with over 300 member companies, maintains its own credit risk policies and does not extend unsecured credit to non-investment grade companies. Losses resulting from a PJM member default are shared by all other members using a predetermined formula. At December 31, 2011 and 2010, EMG's account receivable due from PJM was $62 million and $64 million, respectively.

For the years ended December 31, 2011 and 2010, a second customer, Constellation Energy Commodities Group, Inc. accounted for less than 10% and, in 2009, 16% of EMG's consolidated operating revenues. Sales to Constellation are primarily generated from the coal plants and 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 Standard & Poor's Ratings Services (S&P) and Baa3 by Moody's. At December 31, 2011 and 2010, EMG's account receivable due from Constellation was $7 million and $32 million, respectively.

Margin and Collateral Deposits

Margin and collateral deposits include cash deposited with counterparties and brokers, and cash received from counterparties and brokers as credit support under energy contracts. The amount of margin and collateral deposits generally varies based on

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changes in the fair value of the related positions. Edison International nets counterparty receivables and payables where balances exist under master netting agreements. Edison International presents the portion of its margin and collateral deposits netted with its derivative positions on its consolidated balance sheets. The following table summarizes margin and collateral deposits provided to and received from counterparties:

(in millions)	December 31, 2011	December 31, 2010
Collateral provided to counterparties:		
Offset against derivative liabilities	$ 53	$ 8
Reflected in margin and collateral deposits	58	65
Collateral received from counterparties:		
Offset against derivative assets	53	52

Note 7. Income Taxes

Current and Deferred Taxes

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

	Years ended December 31,		
(in millions)	2011	2010	2009
Income (loss) from continuing operations before income taxes	$(264)	$1,657	$854
Discontinued operations before income taxes	1	13	(7)
Income (loss) before income tax	$(263)	$1,670	$847

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

	Years ended December 31,		
(in millions)	2011	2010	2009
Current:			
Federal	$(223)	$(432)	$1,211
State	36	(86)	361
	(187)	(518)	1,572
Deferred:			
Federal	(9)	892	(1,638)
State	(92)	(20)	(32)
	(101)	872	(1,670)
Total continuing operations	(288)	354	(98)
Discontinued operations	4	9	(2)
Total	$(284)	$363	$(100)

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The components of net accumulated deferred income tax liability are:

(in millions)	December 31, 2011	2010
Deferred tax assets:		
Property and software related	$728	$655
Unrealized gains and losses	385	400
Loss and credit carryforwards	689	97
Regulatory balancing accounts	89	230
Pension and PBOPs	179	183
Other	1,028	890
Total	$3,098	$2,455
Deferred tax liabilities:		
Property-related	$7,140	$6,637
Leveraged leases	150	177
Capitalized software costs	324	293
Regulatory balancing accounts	301	293
Unrealized gains and losses	374	389
Other	296	315
Total	$8,585	$8,104
Accumulated deferred income tax liability – net	$5,487	$5,649
Classification of accumulated deferred income taxes – net:		
Included in deferred credits and other liabilities	$5,396	$5,625
Included in current liabilities	$91	$24

As of December 31, 2011, Edison International had $217 million of federal tax credit carryforwards of which $194 million expire between 2029 and 2031 and the remainder has no expiration date. Additionally, there were $476 million of net operating loss carryforwards of which $20 million expire between 2015 and 2023, and the remainder expire in 2031.

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Effective Tax Rate

The table below provides a reconciliation of income tax expense computed at the federal statutory income tax rate to the income tax provision from continuing operations.

	Years ended December 31,		
(in millions)	2011	2010	2009
Income (loss) from continuing operations before income taxes	$(264)	$1,657	$854
Net income attributable to noncontrolling interests in the Big 4 projects	—	—	(48)
Adjusted income (loss) from continuing operations before income taxes	$(264)	$1,657	$806
Provision for income tax at federal statutory rate of 35%	(92)	580	282
Increase (decrease) in income tax from:			
Items presented with related state income tax, net:			
Global Settlement related[1]	—	(175)	(318)
Change in tax accounting method for asset removal costs[2]	—	(40)	—
State tax – net of federal benefit	(19)	60	48
Employee benefits	(16)	—	—
Health care legislation[3]	—	39	—
Production and housing credits	(68)	(66)	(63)
Property-related	(76)	(47)	(57)
Other	(17)	3	10
Total income tax expense from continuing operations	$(288)	$354	$(98)
Effective tax rate	*	21.4%	*

* Not meaningful

1 Edison International and the IRS finalized the terms of a Global Settlement on May 5, 2009. The Global Settlement resolved federal tax disputes related to Edison Capital's cross-border, leveraged leases through 2009, and all other outstanding federal tax disputes and affirmative claims for tax years 1986 through 2002. Pursuant to the Global Settlement, Edison Capital terminated its interests in the cross-border leases and received net proceeds of $1.385 billion. The Global Settlement and termination of the Edison Capital cross-border leases resulted in a consolidated after-tax earnings charge of $254 million recorded in 2009. During 2010, Edison International recognized a $175 million earnings benefit from the acceptance by the California Franchise Tax Board of the IRS tax positions finalized in 2009 and receipt of the final interest determination from the Franchise Tax Board.

2 During the second quarter of 2010, the IRS approved Edison International's request to change its tax accounting method for asset removal costs primarily related to SCE's infrastructure replacement program. As a result, Edison International recognized a $40 million earnings benefit (of which $28 million relates to asset removal costs incurred prior to 2010) from deducting asset removal costs earlier in the construction cycle. These deductions were recorded on a flow-through basis as required by the CPUC.

3 During the first quarter of 2010, Edison International recorded a $39 million non-cash charge to reverse previously recognized federal tax benefits eliminated by the federal health care legislation enacted in March 2010. The health care law eliminated the federal tax deduction for retiree health care costs to the extent those costs are eligible for federal Medicare Part D subsidies.

The CPUC requires flow-through ratemaking treatment for the current tax benefit arising from certain property-related and other temporary differences which reverse over time. The accounting treatment for these temporary differences results in recording regulatory assets and liabilities for amounts that would otherwise be recorded to deferred income tax expense.

Accounting for Uncertainty in Income Taxes

Authoritative guidance related to accounting for uncertainty in income taxes 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 upon examination. The guidance requires the disclosure of all unrecognized tax benefits, which includes both the reserves recorded for tax positions on filed tax returns and the unrecognized portion of affirmative claims.

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Unrecognized Tax Benefits

The following table provides a reconciliation of unrecognized tax benefits:

(in millions)	2011	2010	2009
Balance at January 1,	$565	$664	$2,237
Tax positions taken during the current year:			
Increases	39	42	102
Tax positions taken during a prior year:			
Increases	102	273	201
Decreases	(75)	(332)	(224)
Decreases for settlements during the period	—	(82)	(1,652)
Balance at December 31,	$631	$565	$664

As of December 31, 2011 and 2010, $532 million and $455 million, respectively, of the unrecognized tax benefits, if recognized, would impact the effective tax rate.

Edison International's federal income tax returns and its California combined franchise tax returns are currently open for years subsequent to 2002. In addition, specific California refund claims made by Edison International for years 1991 through 2002 are currently under review by the Franchise Tax Board. The IRS examination phase of tax years 2003 through 2006 was completed in the fourth quarter of 2010, which included proposed adjustments for the following two items:

- A proposed adjustment increasing the taxable gain on the 2004 sale of EMG's international assets, which if sustained, would result in a federal tax payment of approximately $193 million, including interest and penalties through December 31, 2011 (the IRS has asserted a 40% penalty for understatement of tax liability related to this matter).
- A proposed adjustment to disallow a component of SCE's repair allowance deduction, which if sustained, would result in a federal tax payment of approximately $93 million, including interest through December 31, 2011.

Edison International disagrees with the proposed adjustments and filed a protest with the IRS in the first quarter of 2011.

Accrued Interest and Penalties

The total amount of accrued interest and penalties related to Edison International's income tax liabilities was $242 million and $213 million as of December 31, 2011 and 2010, respectively.

The net after-tax interest and penalties recognized in income tax expense was $18 million in 2011, compared to a benefit of $153 million and $80 million in 2010 and 2009, respectively.

Repair Deductions

In 2009, Edison International made a voluntary election to change its tax accounting method for certain repair costs incurred on SCE's transmission, distribution and generation assets. The change in tax accounting method resulted in a $192 million cash benefit realized in the fourth quarter of 2009. In August of 2011 the IRS issued guidance on repair deductions and changes in accounting method related to transmission and distribution assets. Based on this guidance, SCE will include a second change in tax accounting method in its 2011 tax return. SCE does not expect any cash impact in 2011 due to its current net operating loss position. Regulatory treatment for the incremental deductions taken after the voluntary election to change SCE's tax accounting method for certain repair costs will be addressed in SCE's 2012 GRC. Due to the pending regulatory decision, SCE has not recognized an earnings benefit or regulatory asset related to this method change and incremental deductions taken in 2009, 2010 and 2011.

Note 8. 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 $99 million in 2011, $80 million in 2010 and $83 million in 2009.

Pension Plans and Postretirement Benefits Other Than Pensions

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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 $286 million for the year ending December 31, 2012. Annual contributions made to most of SCE's pension plans are currently recovered through CPUC-approved regulatory mechanisms. Annual contributions to these plans are expected to be, at a minimum, equal to the related annual expense.

The funded position of Edison International's pension is very sensitive to changes in market conditions. Changes in overall interest rate levels significantly affect the company's liabilities, while assets held in the various trusts established to fund Edison International's long-term pension are affected by movements in the equity and bond markets. The market value of the investments (reflecting investment returns, contributions and benefit payments) within the plan trusts declined 35% during 2008. This reduction in value of plan assets combined with increased liabilities has resulted in a change in the pension plan funding status from a surplus to a material deficit, which will result in increased future expense and cash contributions. The Edison International pension remains underfunded as liabilities have increased significantly as a result of steady declines in interest rates. Due to SCE's regulatory recovery treatment, the unfunded status is offset by a regulatory asset. In the 2009 GRC, SCE requested recovery of and continued balancing account treatment for amounts contributed to these trusts. SCE requested the continuation of this approach in the 2012 GRC.

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Information on plan assets and benefit obligations is shown below:

	Years ended December 31,	
(in millions)	2011	2010
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	$4,080	$3,688
Service cost	165	149
Interest cost	210	210
Amendments	—	6
Actuarial loss	327	210
Benefits paid	(289)	(183)
Projected benefit obligation at end of year	$4,493	$4,080
Change in plan assets		
Fair value of plan assets at beginning of year	$3,235	$2,857
Actual return on plan assets	61	434
Employer contributions	146	127
Benefits paid	(289)	(183)
Fair value of plan assets at end of year	$3,153	$3,235
Funded status at end of year	$(1,340)	$(845)
Amounts recognized in the consolidated balance sheets consist of:		
Current liabilities	$(11)	$(12)
Long-term liabilities	(1,329)	(833)
	$(1,340)	$(845)
Amounts recognized in accumulated other comprehensive loss consist of:		
Prior service cost	$1	$1
Net loss	139	116
	$140	$117
Amounts recognized as a regulatory asset:		
Prior service cost	$34	$40
Net loss	955	500
	$989	$540
Total not yet recognized as expense	$1,129	$657
Accumulated benefit obligation at end of year	$4,157	$3,736
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	$4,493	$4,080
Accumulated benefit obligation	4,157	3,736
Fair value of plan assets	3,153	3,235
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	4.5%	5.25%
Rate of compensation increase	4.5%	5.0%

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Expense components and other amounts recognized in other comprehensive income:
Expense components are:

(in millions)	Years ended December 31, 2011	2010	2009
Service cost	$ 165	$ 149	124
Interest cost	210	210	207
Expected return on plan assets	(238)	(210)	(169)
Amortization of prior service cost	7	8	11
Amortization of net loss	28	22	61
Expense under accounting standards	$ 172	$ 179	$ 234
Regulatory adjustment – deferred	(28)	(52)	(94)
Total expense recognized	$ 144	$ 127	140

Other changes in plan assets and benefit obligations recognized in other comprehensive income:

(in millions)	Years ended December 31, 2011	2010	2009
Net loss	$ 35	$ 30	$ 17
Amortization of prior service cost	—	(1)	(1)
Amortization of net loss	(13)	(10)	(11)
Total recognized in other comprehensive loss	$ 22	$ 19	$ 5
Total recognized in expense and other comprehensive income	$ 166	$ 146	$ 145

In accordance with authoritative guidance on rate-regulated enterprises, Edison International records regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for the portion of SCE's postretirement benefit plans that are recoverable in utility rates. The estimated net loss and prior service cost that will be amortized to expense in 2012 are $67 million and $4 million, respectively; $17 million of the net loss is expected to be reclassified from accumulated other comprehensive loss.

The following are weighted-average assumptions used to determine expense:

	Years ended December 31, 2011	2010	2009
Discount rate	5.25 %	6.0 %	6.25 %
Rate of compensation increase	5.0 %	5.0 %	5.0 %
Expected 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)	Years ended December 31,
2012	$ 302
2013	310
2014	316
2015	329
2016	338
2017 – 2021	1,738

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Postretirement Benefits Other Than Pensions

Most non-union employees retiring at or after age 55 with at least 10 years of service may be eligible for postretirement medical, dental, vision and life insurance and other benefits. Eligibility for a company contribution toward the cost of these benefits in retirement depends on a number of factors, including the employee's hire date. The expected contributions (all by the employer) to the PBOP trust are $65 million for the year ending December 31, 2012. Annual contributions made to SCE plans are currently recovered through CPUC-approved regulatory mechanisms and are expected to be, at a minimum, equal to the total annual expense for these plans.

The funded position of Edison International's PBOP is very sensitive to changes in market conditions. Changes in overall interest rate levels significantly affect the company's liabilities, while assets held in the various trusts established to fund Edison International's other postretirement benefits are affected by movements in the equity and bond markets. 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's underfunded status and will also result in increased future expense and increased future contributions. Edison International's PBOP is underfunded as liabilities have increased significantly as a result of steady declines in interest rates. Due to SCE's regulatory recovery treatment, the unfunded status is offset by a regulatory asset. In the 2009 GRC, SCE requested recovery of and continued balancing account treatment for amounts contributed to this trust. SCE requested the continuation of this approach in the 2012 GRC.

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Information on plan assets and benefit obligations is shown below:

	Years ended December 31,	
(in millions)	2011	2010
Change in benefit obligation		
Benefit obligation at beginning of year	$2,425	$2,110
Service cost	43	37
Interest cost	121	127
Amendments	—	23
Actuarial loss	47	216
Plan participants' contributions	18	17
Medicare Part D subsidy received	5	5
Benefits paid	(106)	(110)
Benefit obligation at end of year	$2,553	$2,425
Change in plan assets		
Fair value of plan assets at beginning of year	$1,606	$1,459
Actual return on assets	11	175
Employer contributions	36	60
Plan participants' contributions	18	17
Medicare Part D subsidy received	5	5
Benefits paid	(106)	(110)
Fair value of plan assets at end of year	$1,570	$1,606
Funded status at end of year	$(983)	$(819)
Amounts recognized in the consolidated balance sheets consist of:		
Current liabilities	$(19)	$(20)
Long-term liabilities	(964)	(799)
	$(983)	$(819)
Amounts recognized in accumulated other comprehensive loss (income) consist of:		
Prior service cost (credit)	$8	$7
Net loss	27	28
	$35	$35
Amounts recognized as a regulatory asset (liability):		
Prior service credit	$(125)	$(161)
Net loss	839	718
	$714	$557
Total not yet recognized as expense	$749	$592
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	4.75%	5.5%
Assumed health care cost trend rates:		
Rate assumed for following year	9.50%	9.75%
Ultimate rate	5.25%	5.5%
Year ultimate rate reached	2019	2019

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Expense components and other amounts recognized in other comprehensive income:
Expense components are:

	Years ended December 31,		
(in millions)	2011	2010	2009
Service cost	$43	$37	30
Interest cost	121	127	122
Expected return on plan assets	(111)	(101)	(81)
Amortization of prior service credit	(36)	(38)	(34)
Amortization of net loss	27	36	45
Total expense	$44	$61	$82

Other changes in plan assets and benefit obligations recognized in other comprehensive income:

	Years ended December 31,		
(in millions)	2011	2010	2009
Net loss (gain)	$(1)	$13	$(8)
Prior service cost (credit)	—	11	(3)
Amortization of prior service credit	1	2	2
Amortization of net loss	(1)	(1)	(1)
Total recognized in other comprehensive income	$(1)	$25	$(10)
Total recognized in expense and other comprehensive income	$43	$86	$72

In accordance with authoritative guidance on rate-regulated enterprises, Edison International records regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for the portion of SCE's postretirement benefit plans that are recoverable in utility rates. The estimated net loss and prior service cost (credit) that will be amortized to expense in 2012 are $46 million and $(35) million, respectively, including $2 million and zero, respectively, expected to be reclassified from accumulated other comprehensive loss.

The following are weighted-average assumptions used to determine expense:

	Years ended December 31,		
	2011	2010	2009
Discount rate	5.5%	6.0%	6.25%
Expected long-term return on plan assets	7.0%	7.0%	7.0%
Assumed health care cost trend rates:			
Current year	9.75%	8.25%	8.75%
Ultimate rate	5.5%	5.5%	5.5%
Year ultimate rate reached	2019	2016	2016

Increasing the health care cost trend rate by one percentage point would increase the accumulated benefit obligation as of December 31, 2011 by $297 million and annual aggregate service and interest costs by $16 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated benefit obligation as of December 31, 2011 by $247 million and annual aggregate service and interest costs by $13 million.

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The following benefit payments are expected to be paid:

	Year ending December 31,	
(in millions)	Before Subsidy[1]	Net
2012	$100	$94
2013	108	102
2014	117	110
2015	126	119
2016	136	128
2017 – 2021	809	755

[1] Medicare Part D prescription drug benefits

Plan Assets

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. Target allocations for pension plan assets are 30% for U.S. equities, 16% for non-U.S. equities, 35% for fixed income, 15% for opportunistic and/or alternative investments and 4% for other investments. Target allocations for PBOP plan assets are 41% for U.S. equities, 17% for non-U.S. equities, 34% for fixed income, 7% for opportunistic and/or alternative investments, and 1% for other investments. 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 investment 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.
- Fixed Income: Fixed income securities issued or guaranteed by the United States government, non-United States governments, government agencies and instrumentalities including municipal bonds, mortgage backed securities and corporate debt obligations. A portion of the fixed income positions may be held in debt securities that are below investment grade.

Opportunistic, Alternative and Other Investments:

- Opportunistic: Investments in short to intermediate term market opportunities. Investments may have fixed income and/or equity characteristics and may be either liquid or illiquid.
- Alternative: Limited partnerships that invest in non-publicly traded entities.
- Other: Investments diversified among multiple asset classes such as global equity, fixed income currency and commodities markets. Investments are made in liquid instruments within and across markets. The investment returns are expected to approximate the plans' expected investment returns.

Asset class portfolio weights are permitted to range within plus or minus 3%. Where approved by the fiduciary investment committee, futures contracts are used for portfolio rebalancing and to reallocate portfolio cash positions. Where authorized, a few of the plans' investment managers employ limited use of derivatives, including futures contracts, options, options on futures and interest rate swaps in place of direct investment in securities to gain efficient exposure to markets. Derivatives are not used to leverage the plans or any portfolios.

Determination of the Expected Long-Term Rate of Return on Assets

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

Our capital markets return forecast methodologies primarily use a combination of historical market data, current market conditions, proprietary forecasting expertise, complex models to develop asset class return forecasts and a building block approach. The forecasts are developed using variables such as real risk-free interest, inflation, and asset class specific risk premiums. For equities, the risk premium is based on an assumed average equity risk premium of 6% over cash. The forecasted return on private equity and opportunistic investments are estimated at a 3% premium above public equity, reflecting a premium for higher volatility and liquidity. For fixed income, the risk premium is based off of a comprehensive modeling of credit spreads.

Fair Value of Plan Assets

The PBOP Plan and the Southern California Edison Company Retirement Plan Trust (Master Trust) assets include investments in equity securities, U.S. treasury securities, other fixed-income securities, common/collective funds, mutual funds, other investment entities, foreign exchange and interest rate contracts, and partnership/joint ventures. Equity securities, U.S. treasury securities, mutual and money market funds are classified as Level 1 as fair value is determined by observable, unadjusted quoted market prices in active or highly liquid and transparent markets. Common/collective funds are valued at the net asset value ("NAV") of shares held. Although common/collective funds are determined by observable prices, they are classified as Level 2 because they trade in markets that are less active and transparent. The fair value of the underlying investments in equity mutual funds and equity common/collective funds are based upon stock-exchange prices. The fair value of the underlying investments in fixed-income common/collective funds, fixed-income mutual funds and other fixed income securities including municipal bonds are 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. Foreign exchange and interest rate contracts are classified as Level 2 because the values are based on observable prices but are not traded on an exchange. Futures contracts trade on an exchange and therefore are classified as Level 1. One of the partnerships is classified as Level 2 since this investment can be readily redeemed at NAV and the underlying investments are liquid, publicly traded fixed-income securities which have observable prices. The remaining partnerships/joint ventures are classified as Level 3 because fair value is determined primarily based upon management estimates of future cash flows. Other investment entities are valued similarly to common collective funds and are therefore classified as Level 2. The Level 1 registered investment companies are either mutual or money market funds. The remaining funds in this category are readily redeemable at NAV and classified as Level 2 and are discussed further at footnote 7 to the pension plan master trust investments table below.

Edison International reviews the process/procedures of both the pricing services and the trustee to gain an understanding of the inputs/assumptions and valuation techniques used to price each asset type/class. The trustee and Edison International's validation procedures for pension and PBOP equity and fixed income securities are the same as the nuclear decommissioning trusts. For further discussion see Note 4. The values of Level 1 mutual and money market funds are publicly quoted. The trustees obtain the values of common/collective and other investment funds from the fund managers. The values of partnerships are based on partnership valuation statements updated for cash flows. SCE's investment managers corroborate the trustee fair values.

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Pension Plan

The following table sets forth the Master Trust investments that were accounted for at fair value as of December 31, 2011 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Total
Corporate stocks[1]	$642	$—	$—	$642
Partnerships/joint ventures[2]	—	140	448	588
Common/collective funds[3]	—	582	—	582
Corporate bonds[4]	—	497	—	497
U.S. government and agency securities[5]	104	351	—	455
Other investment entities[6]	—	247	—	247
Registered investment companies[7]	79	29	—	108
Interest-bearing cash	5	—	—	5
Other	(1)	69	—	68
Total	$829	$1,915	$448	$3,192
Receivables and payables, net				(39)
Net plan assets available for benefits				$3,153

The following table sets forth the Master Trust investments that were accounted for at fair value as of December 31, 2010 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Total
Corporate stocks[1]	$786	$—	$—	$786
Partnerships/joint ventures[2]	—	155	345	500
Common/collective funds[3]	—	600	—	600
Corporate bonds[4]	—	555	—	555
U.S. government and agency securities[5]	84	316	—	400
Other investment entities[6]	—	236	—	236
Registered investment companies				