EDISON INTERNATIONAL
Form 10-Q
May 08, 2009

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

FORM 10-Q

(Mark One)
ý **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2009

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

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

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 ý No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, 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 o No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ý	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	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 ý

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Class	Outstanding at May 5, 2009
Common Stock, no par value	**325,811,206**

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GLOSSARY

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

AB	Assembly Bill
AFUDC	allowance for funds used during construction
APS	Arizona Public Service Company
ARO(s)	asset retirement obligation(s)
Bcf	billion cubic feet
Btu	British thermal units
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CARB	California Air Resources Board
Commonwealth Edison	Commonwealth Edison Company
CDWR	California Department of Water Resources
CEC	California Energy Commission
CONE	cost of new entry
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
DOE	United States Department of Energy
DOJ	United States Department of Justice
DPV2	Devers-Palo Verde II
DRA	Division of Ratepayer Advocates
DWP	Los Angeles Department of Water & Power
EME	Edison Mission Energy
EME Homer City	EME Homer City Generation L.P.
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
FIN 39-1	Financial Accounting Standards Board Interpretation No. 39-1, Amendment of FASB Interpretation No. 39
FIN 48	Financial Accounting Standards Board Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FAS 109
Fitch	Fitch Ratings
FSP SFAS 142-3	FASB Staff Position No. SFAS 142-3, Determination of the Useful Life of Intangible Assets
FTRs	firm transmission rights
GAAP	generally accepted accounting principles
GHG	greenhouse gas

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GLOSSARY (Continued)

Global Settlement	A settlement between Edison International and the IRS that resolves asserted deficiencies related to Edison International's deferral of income taxes associated with certain of its cross-border, leveraged leases in their entirety and all other outstanding tax disputes for open tax years 1986 through 2002.
GRC	General Rate Case
GWh	gigawatt-hours
Illinois Plants	EME's largest power plants (fossil fuel) located in Illinois
Investor-Owned Utilities	SCE, SDG&E and PG&E
IRS	Internal Revenue Service
ISO	California Independent System Operator
kWh(s)	kilowatt-hour(s)
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MEHC	Mission Energy Holding Company
Midwest Generation	Midwest Generation, LLC
MMBtu	million British thermal units
Mohave	Mohave Generating Station
Moody's	Moody's Investors Service
MRTU	Market Redesign and Technology Upgrade
MW	megawatts
MWh	megawatt-hours
NAPP	Northern Appalachian
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NOV	notice of violation
NO_x	nitrogen oxide
NRC	Nuclear Regulatory Commission
NYISO	New York Independent System Operator
PADEP	Pennsylvania Department of Environmental Protection
Palo Verde	Palo Verde Nuclear Generating Station
PBOP(s)	Postretirement benefits other than pension(s)
PBR	performance-based ratemaking
PG&E	Pacific Gas & Electric Company
PJM	PJM Interconnection, LLC
POD	Presiding Officer's Decision
PRB	Powder River Basin
PX	California Power Exchange
QF(s)	qualifying facility(ies)
RICO	Racketeer Influenced and Corrupt Organization
ROE	return on equity
RPM	reliability pricing model
S&P	Standard & Poor's
SAB	Staff Accounting Bulletin
San Onofre	San Onofre Nuclear Generating Station
SCAQMD	South Coast Air Quality Management District

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GLOSSARY (Continued)

SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric
SFAS	Statement of Financial Accounting Standards issued by the FASB
SFAS No. 133	Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities
SFAS No. 141(R)	Statement of Financial Accounting Standards No. 141(R), Business Combinations
SFAS No. 157	Statement of Financial Accounting Standards No. 157, Fair Value Measurements
SFAS No. 158	Statement of Financial Accounting Standards No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans
SFAS No. 160	Statement of Financial Accounting Standards No. 160, Noncontrolling Interests in Consolidated Financial Statements
SFAS No. 161	Statement of Financial Accounting Standards No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133
SIP(s)	State Implementation Plan(s)
SO_2	sulfur dioxide
SRP	Salt River Project Agricultural Improvement and Power District
the Tribes	Navajo Nation and Hopi Tribe
TURN	The Utility Reform Network
US EPA	United States Environmental Protection Agency
VIE(s)	variable interest entity(ies)

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended March 31,	
In millions, except per-share amounts	**2009**	**2008**
	(Unaudited)	
Electric utility	**$ 2,188**	$ 2,379
Competitive power generation	**611**	719
Financial services and other	**13**	15
Total operating revenue	**2,812**	3,113
Fuel	**387**	537
Purchased power	**540**	693
Other operation and maintenance	**969**	961
Depreciation, decommissioning and amortization	**342**	311
Contract buyout/termination and other	**21**	(17)
Total operating expenses	**2,259**	2,485
Operating income	**553**	628
Interest and dividend income	**10**	14
Equity in income (loss) from partnerships and unconsolidated subsidiaries net	**(8)**	2
Other nonoperating income	**26**	25
Interest expense net of amounts capitalized	**(187)**	(171)
Other nonoperating deductions	**(6)**	(12)
Income from continuing operations before income taxes	**388**	486
Income tax expense	**122**	161
Income from continuing operations	**266**	325
Income (loss) from discontinued operations net of tax	**3**	(5)
Net income	**269**	320
Less: Net income attributable to noncontrolling interests	**19**	21
Net income attributable to Edison International	**$ 250**	$ 299
Amounts attributable to Edison International common shareholders:		
Income from continuing operations, net of tax	**$ 247**	$ 304
Income (loss) from discontinued operations, net of tax	**3**	(5)
Net income	**$ 250**	$ 299

Weighted-average shares of common stock outstanding	**326**	326
Basic earnings (loss) per common share attributable to Edison International common shareholders:		
Continuing operations	**$ 0.75**	$ 0.92
Discontinued operations	**0.01**	(0.01)
Total	**$ 0.76**	$ 0.91
Weighted-average shares, including effect of dilutive securities	**327**	329
Diluted earnings (loss) per common share attributable to Edison International common shareholders:		
Continuing operations	**$ 0.75**	$ 0.92
Discontinued operations	**0.01**	(0.01)
Total	**$ 0.76**	$ 0.91
Dividends declared per common share	**$ 0.310**	$ 0.305

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

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EDISON INTERNATIONAL

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended March 31,	
In millions	**2009**	**2008**
	(Unaudited)	
Net income	**$ 269**	$ 320
Other comprehensive income (loss), net of tax:		
Foreign currency translation adjustments net		(3)
Pension and postretirement benefits other than pensions:		
Amortization of net loss included in net income net	**2**	
Unrealized gains (losses) on cash flow hedges:		
Unrealized gains (losses) arising during the period net of income tax expense (benefit) of $98 and $(92) for 2009 and 2008, respectively	**151**	(138)
Reclassification adjustment for losses included in net income net of income tax benefit of $32 and $6 for 2009 and 2008, respectively	**(49)**	(9)
Other comprehensive income (loss)	**104**	(150)
Comprehensive income	**373**	170
Less: Comprehensive income attributable to noncontrolling interests	**19**	21
Comprehensive income attributable to Edison International	**$ 354**	$ 149

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

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EDISON INTERNATIONAL

CONSOLIDATED BALANCE SHEETS

In millions	March 31, 2009	December 31, 2008
	(Unaudited)	
ASSETS		
Cash and equivalents	**$ 3,543**	$ 3,916
Short-term investments	**7**	7
Receivables, less allowances of $37 and $39 for uncollectible accounts at respective dates	**921**	1,006
Accrued unbilled revenue	**335**	328
Fuel inventory	**196**	163
Materials and supplies	**353**	390
Derivative assets	**346**	327
Restricted cash	**3**	3
Margin and collateral deposits	**146**	105
Regulatory assets	**571**	605
Deferred income taxes net		104
Other current assets	**354**	399
Total current assets	**6,775**	7,353
Nonutility property less accumulated depreciation of $2,088 and $2,019 at respective dates	**5,395**	5,374
Nuclear decommissioning trusts	**2,399**	2,524
Investments in partnerships and unconsolidated subsidiaries	**210**	229
Investments in leveraged leases	**2,339**	2,467
Other investments	**92**	89
Total investments and other assets	**10,435**	10,683
Utility plant, at original cost:		
Transmission and distribution	**20,188**	20,006
Generation	**1,833**	1,819
Accumulated depreciation	**(5,606)**	(5,570)
Construction work in progress	**2,649**	2,454
Nuclear fuel, at amortized cost	**257**	260
Total utility plant	**19,321**	18,969
Derivative assets	**604**	244
Restricted cash	**43**	43
Rent payments in excess of levelized rent expense under plant operating leases	**926**	878
Regulatory assets	**5,273**	5,414
Other long-term assets	**1,052**	1,031
Total long-term assets	**7,898**	7,610
Total assets	**$ 44,429**	$ 44,615

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

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EDISON INTERNATIONAL

CONSOLIDATED BALANCE SHEETS

In millions, except share amounts	March 31, 2009	December 31, 2008
	(Unaudited)	
LIABILITIES AND EQUITY		
Short-term debt	**$ 1,558**	$ 2,143
Long-term debt due within one year	**274**	174
Accounts payable	**757**	1,031
Accrued taxes	**675**	590
Accrued interest	**224**	187
Counterparty collateral	**25**	8
Customer deposits	**233**	228
Book overdrafts	**185**	224
Derivative liabilities	**170**	178
Regulatory liabilities	**972**	1,111
Deferred income taxes net	**11**	
Other current liabilities	**756**	823
Total current liabilities	**5,840**	6,697
Long-term debt	**11,198**	10,950
Deferred income taxes net	**5,802**	5,717
Deferred investment tax credits	**107**	109
Customer advances	**130**	137
Derivative liabilities	**777**	776
Pensions and benefits	**2,899**	2,860
Asset retirement obligations	**3,085**	3,042
Regulatory liabilities	**2,542**	2,481
Other deferred credits and other long-term liabilities	**1,097**	1,137
Total deferred credits and other liabilities	**16,439**	16,259
Total liabilities	**33,477**	33,906
Commitments and contingencies (Note 6)		
Common stock, no par value (325,811,206 shares outstanding at each date)	**2,278**	2,272
Accumulated other comprehensive income	**271**	167
Retained earnings	**7,219**	7,078
Total Edison International's common shareholders' equity	**9,768**	9,517
Noncontrolling interests other	**277**	285
Preferred and preference stock of utility not subject to mandatory redemption	**907**	907
Total equity	**10,952**	10,709
Total liabilities and equity	**$ 44,429**	$ 44,615

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

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EDISON INTERNATIONAL

CONSOLIDATED STATEMENTS OF CASH FLOWS

In millions	Three Months Ended March 31, 2009	2008
	(Unaudited)	
Cash flows from operating activities:		
Net income	**$ 269**	$ 320
Less: Income (loss) from discontinued operations	**3**	(5)
Income from continuing operations	**266**	325
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation, decommissioning and amortization	**342**	311
Net nuclear decommissioning trust loss in nuclear ARO regulatory assets and liabilities	**32**	32
Other amortization	**26**	27
Contract buyout/termination and other	**21**	(17)
Stock-based compensation	**5**	6
Deferred income taxes and investment tax credits	**63**	31
Equity in (income) loss from partnerships and unconsolidated subsidiaries net	**8**	(2)
Income from leveraged leases	**(11)**	(13)
Regulatory assets	**388**	77
Regulatory liabilities	**(144)**	186
Levelized rent expense	**(49)**	(48)
Derivative assets	**(199)**	(96)
Derivative liabilities	**(21)**	(162)
Other assets	**(13)**	(20)
Other liabilities	**(32)**	92
Margin and collateral deposits net of collateral received	**(23)**	(21)
Receivables and accrued unbilled revenue	**78**	22
Inventory and other current assets	**49**	(35)
Book overdrafts	**(34)**	(20)
Accrued interest and taxes	**122**	133
Accounts payable and other current liabilities	**(188)**	(215)
Distributions and dividends from unconsolidated entities	**(3)**	(2)
Operating cash flows from discontinued operations	**3**	(5)
Net cash provided by operating activities	**686**	586
Cash flows from financing activities:		
Long-term debt issued	**750**	677
Long-term debt issuance costs	**(10)**	(9)
Long-term debt repaid	**(179)**	(7)
Bonds repurchased	**(219)**	(212)
Preference stock redeemed		(7)
Short-term debt financing net	**(585)**	(100)
Shares purchased for stock-based compensation	**(4)**	(24)
Proceeds from stock option exercises	**3**	7
Excess tax benefits related to stock-based awards	**2**	6
Dividends and distributions to noncontrolling interests	**(25)**	(30)
Dividends paid	**(101)**	(99)

Net cash provided (used) by financing activities	**$**	**(368)**	$	202

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

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EDISON INTERNATIONAL

CONSOLIDATED STATEMENTS OF CASH FLOWS

In millions	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
	(Unaudited)	
Cash flows from investing activities:		
Capital expenditures	$ (785)	$ (705)
Purchase of interest of acquired companies	(6)	
Proceeds from termination of leases	121	
Proceeds from sale of property and interests in projects		2
Proceeds from nuclear decommissioning trust sales	658	829
Purchases of nuclear decommissioning trust investments and other	(700)	(859)
Proceeds from partnerships and unconsolidated subsidiaries, net of investment	10	9
Maturities and sales of short-term investments	1	47
Purchase of short-term investments	(1)	(1)
Restricted cash		2
Customer advances for construction and other investments	11	(8)
Net cash used by investing activities	(691)	(684)
Net increase (decrease) in cash and equivalents	(373)	104
Cash and equivalents, beginning of period	3,916	1,441
Cash and equivalents, end of period	$ 3,543	$ 1,545

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

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EDISON INTERNATIONAL

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Management's Statement

In the opinion of management, all adjustments, including recurring accruals, have been made that are necessary to fairly state the consolidated financial position, results of operations and cash flows in accordance with accounting principles generally accepted in the United States of America for the periods covered by this quarterly report on Form 10-Q. The results of operations for the three months ended March 31, 2009 are not necessarily indicative of the operating results for the full year.

This quarterly report should be read in conjunction with Edison International's Annual Report to Shareholders incorporated by reference into Edison International's Annual Report on Form 10-K for the year ended December 31, 2008 filed with the Securities and Exchange Commission.

Note 1. Summary of Significant Accounting Policies

Basis of Presentation

Edison International's significant accounting policies were described in Note 1 of "Notes to Consolidated Financial Statements" included in its 2008 Annual Report on Form 10-K. Edison International follows the same accounting policies for interim reporting purposes.

The December 31, 2008 condensed balance sheet data was derived from audited financial statements, but does not include all disclosures required by accounting principles generally accepted in the United States of America.

Certain prior-year reclassifications have been made to conform to the current year financial statement presentation mostly pertaining to the adoption of SFAS No. 160 and the elimination of the previously reported income statement caption "Provision for regulatory adjustment clauses net" through classifications within relevant captions including "Operating revenue," "Purchased power," "Other operation and maintenance" and "Depreciation, decommissioning and amortization." Except as indicated, amounts presented in the Notes to the Consolidated Financial Statements relate to continuing operations.

Cash and Equivalents

Cash and cash equivalents as of March 31, 2009 and December 31, 2008 consisted of the following:

In millions	**March 31, 2009**	**December 31, 2008**
	(Unaudited)	
Cash	**$ 283**	$ 178
Money market funds	**$ 3,248**	$ 3,543
U.S. government agency securities		164
Commercial paper		30
Time deposits (certificates of deposit)	**12**	1
Total cash equivalents	**$ 3,260**	$ 3,738
Total cash and cash equivalents	**$ 3,543**	$ 3,916

Cash equivalents, with the exception of money market funds, were stated at amortized cost plus accrued interest. The carrying value of cash equivalents approximates fair value due to maturities of

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less than three months. For further discussion of money market funds, see Note 10. Additionally, cash and equivalents of $83 million and $89 million at March 31, 2009 and December 31, 2008, respectively, are included for four projects that Edison International is consolidating under an accounting interpretation for VIEs.

Earnings Per Common Share

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

	Three Months Ended March 31,			
In millions		**2009**		**2008**
	(Unaudited)			
Basic earnings per share continuing operations:				
Income from continuing operations, net of tax	**$**	**247**	$	304
Gain on redemption of preferred stock				2
Participating securities dividends		**(2)**		(5)
Income from continuing operations available to common shareholders	**$**	**245**	$	301
Weighted average common shares outstanding		**326**		326
Basic earnings per share continuing operations	**$**	**0.75**	$	0.92
Diluted earnings per share continuing operations:				
Income from continuing operations available to common shareholders	**$**	**245**	$	301
Income impact of assumed conversions				2
Income from continuing operations available to common shareholders and assumed conversions	**$**	**245**	$	303
Weighted average common shares outstanding		**326**		326
Incremental shares from assumed conversions		**1**		3
Adjusted weighted average shares diluted		**327**		329
Diluted earnings per share continuing operations	**$**	**0.75**	$	0.92

Stock-based compensation awards to purchase 8,660,629 and 83,901 shares of common stock for the three months ended March 31, 2009 and 2008, 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; and therefore, the effect would have been antidilutive.

Margin and Collateral Deposits

Margin and collateral deposits include cash deposited with counterparties and brokers as credit support under energy contracts. The amount of margin and collateral deposits generally varies based on changes in the value of the positions. In accordance with FIN No. 39-1, Edison International presents a

portion of its margin and cash collateral deposits net with its derivative positions on its consolidated balance sheets. Amounts recognized for cash collateral provided to others that have been offset against derivative liabilities totaled $163 million and $123 million at March 31, 2009 and December 31, 2008, respectively. Amounts recognized for cash collateral received from others that have been offset against derivative assets totaled $374 million and $225 million at March 31, 2009 and December 31, 2008, respectively.

New Accounting Pronouncements

Accounting Pronouncements Adopted

Effective January 1, 2009, Edison International adopted SFAS No. 157 for nonrecurring fair value measurements of nonfinancial assets and liabilities. The adoption of SFAS No. 157 for nonrecurring fair value measurements did not have a material impact on Edison International's consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141(R), which establishes principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date fair value. SFAS No. 141(R) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) applies prospectively to business combinations for which the acquisition date is on or after fiscal years beginning on or after January 1, 2009. Adoption of this pronouncement had no impact on consolidated results of operations, financial position or cash flows because there were no business combinations during the first quarter of 2009.

In April 2009, the FASB issued FSP SFAS No. 141(R)-1, "Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies" to amend guidance in SFAS No. 141(R). FSP SFAS No. 141(R)-1 addresses the initial recognition, measurement and subsequent accounting for assets and liabilities arising from contingencies in a business combination, and requires that such assets acquired or liabilities assumed be initially recognized at fair value at the acquisition date if fair value can be determined during the measurement period. If the acquisition-date fair value cannot be determined, the asset acquired or liability assumed arising from a contingency is recognized only if certain criteria are met. This position also requires that a systematic and rational basis for subsequently measuring and accounting for the assets or liabilities be developed depending on their nature. This position shall be effective for assets or liabilities arising from contingencies in business combinations for which the acquisition date is on or after fiscal years beginning January 1, 2009. Adoption of this standard had no impact on Edison International's consolidated results of operations, financial position or cash flows because there were no business combinations during the first quarter of 2009.

In December 2007, the FASB issued SFAS No. 160, which requires an entity to present noncontrolling interests that reflect the ownership interests in subsidiaries held by parties other than the entity, within the equity section but separate from the entity's equity in the consolidated financial statements. It also requires the amount of consolidated net income attributable to the parent and to the noncontrolling interests to be clearly identified and presented on the face of the consolidated statement of income; changes in ownership interests to be accounted for similarly as equity transactions; and when a subsidiary is deconsolidated, any retained noncontrolling equity investment in the former subsidiary and the gain or loss on the deconsolidation of the subsidiary to be measured at fair value. Edison International adopted SFAS No. 160 effective January 1, 2009 and retrospectively applied this standard as of December 31, 2008. In accordance with this standard, Edison International reclassified "Noncontrolling interests other" of $285 million and "Preferred and preference stock of utility not

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subject to mandatory redemption" of $907 million to a component of equity. For additional information, see Note 7.

In March 2008, the FASB issued SFAS No. 161, which requires additional disclosures related to derivative instruments, including how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. Edison International adopted this pronouncement effective January 1, 2009. Since SFAS No. 161 impacts disclosures only, the adoption of this standard did not have an impact on Edison International's consolidated results of operations, financial position or cash flows. For additional information regarding the adoption, see Note 2.

In April 2008, the FASB issued FSP FAS No. 142-3 which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, "Goodwill and Other Intangible Assets." The intent of the position is to improve the consistency between the useful life of a recognized intangible asset under SFAS No. 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No. 141(R) and other GAAP. Edison International adopted this pronouncement effective, January 1, 2009. The adoption of this position had no impact on Edison International's consolidated results of operations, financial position or cash flows.

In November 2008, the FASB ratified the consensus in EITF Issue No. 08-6, "Equity Method Investment Accounting Considerations." This issue clarifies the accounting for certain transactions and impairment considerations involving equity method investments. Effective January 1, 2009, Edison International adopted this issue prospectively. The adoption had no impact on its consolidated financial statements.

Accounting Pronouncements Not Yet Adopted

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

In April 2009, the FASB issued FSP SFAS No. 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions that Are Not Orderly." FSP SFAS No. 157-4 affirms the objective of a fair value measurement, which is to identify the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction at the measurement date between market participants ("exit price") in the current inactive market. FSP SFAS No. 157-4 includes guidance on identifying circumstances that indicate when there is no active market or transactions where the price inputs being used represent distressed or forced sales. If either of these conditions exists, FSP SFAS No. 157-4 provides additional direction for estimating fair value and requires disclosure of a change in valuation technique (and the related inputs) resulting from the application of this position and to quantify its effects, if practicable. Edison International will adopt FSP SFAS No. 157-4 in the second quarter of 2009 and is currently evaluating the impact, if any, that the adoption of this position could have on its consolidated financial statements.

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In April 2009, the FASB issued FSP SFAS No. 115-2, "Recognition and Presentation of Other-Than-Temporary Impairments." FSP SFAS No. 115-2 changes existing guidance for determining whether impairment is other than temporary for debt securities. Under FSP SFAS No. 115-2, an entity would write down to fair value through earnings, impaired debt securities that it currently intends to sell or for which it is more likely than not it will have to sell before recovery. If an entity does not intend and will not be required to sell a debt security but it is probable that the entity will not collect all amounts due, the entity will separate the other-than-temporary impairment into two components: 1) the amount due to credit loss would be recognized in earnings, and 2) the remaining portion would be recognized in other comprehensive income. Upon adoption, a cumulative adjustment may be required for the noncredit component of a previously recognized other-than-temporary impairment. FSP SFAS No. 115-2 requires increased disclosures including the amortized cost basis, credit losses, a potential increase in major security categories and quarterly as well as annual disclosures. Edison International will adopt FSP SFAS No. 115-2 in the second quarter of 2009 and is currently evaluating the impact, if any, that the adoption of this position could have on its consolidated financial statements.

In April 2009, the FASB issued FSP SFAS No. 107-1 and APB No. 28-1, "Interim Disclosures about Fair Value of Financial Instruments." This position requires disclosures about the fair value of all financial instruments, for which it is practicable to estimate that fair value, for interim reporting periods as well as annual statements. Edison International will adopt this position in the second quarter of 2009. Since FSP SFAS No. 107-1 and APB No. 28-1 impacts disclosure only, the adoption of this position will not have an impact on Edison International's consolidated results of operations, financial position or cash flows.

Related Party Transactions

During the first quarter of 2008, a subsidiary of EME was awarded, through a competitive bidding process, a ten-year power sales contract with SCE for the output of a 479 MW gas-peaking facility located in the City of Industry, California, which is referred to as the Walnut Creek project. Deliveries under the power sales agreement are expected to commence in 2013. The project is subject to resolution of uncertainty regarding the availability of required emission credits.

Note 2. Derivative Instruments and Hedging Activities

Electric Utility

Commodity Price Risk

SCE is exposed to commodity price risk from its purchases of capacity and ancillary services to meet peak energy requirements and from exposure to natural gas prices that affect costs associated with power purchased from QFs, fuel tolling arrangements, and its own gas-fired generation, including SCE's Mountainview and peaker plants. Contract energy prices for most nonrenewable QFs are based in large part on the monthly index price of natural gas delivered at the Southern California border. SCE also has power contracts, referred to as tolling arrangements, in which SCE has agreed to provide the natural gas needed for generation under those power contracts or pay for the natural gas based on published index prices. In addition to SCE's Mountainview and peaker plants, approximately 48% of SCE's purchased power supply is subject to natural gas price volatility. Fair value changes in SCE's derivative instruments are expected to be recovered from or refunded to ratepayers and therefore, fair value changes have no impact on earnings, but may temporarily affect cash flows.

Natural Gas and Electricity Price Risk

SCE has an active hedging program in place to minimize ratepayer exposure to variability in market prices; however, to the extent that SCE does not mitigate the exposure to commodity price risk, the

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unhedged portion is subject to the risks and benefits of spot-market price movements, which are ultimately passed-through to ratepayers.

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

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

Notional Volumes of Derivative Instruments

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

Commodity	**Unit of Measure**	**Economic Hedges**
		(Unaudited)
Electricity options, swaps and forward arrangements	MW	24,078
Natural gas options, swaps and forward arrangements	Bcf	248
Congestion revenue rights(1)	MW	548,854
Tolling arrangements(2)	MW	2,556

(1)

During the first quarter of 2008, the CAISO held an auction for FTRs. SCE participated in the CAISO auction and paid $62 million to secure FTRs for the period April 2008 through March 2009. As of March 31, 2009, there were no FTRs outstanding. The FTRs have been replaced with CRRs in the CAISO's market redesign environment. SCE recognized the FTRs at fair value.

In September 2007 and November 2008, the CAISO allocated CRRs for the period April 2009 through December 2017 based on SCE's load requirements. In addition, SCE participated in CAISO auctions for the procurement of additional CRRs. The CRRs meet the definition of a derivative under SFAS No. 133.

(2)

In compliance with a CPUC mandate, SCE held an open, competitive solicitation that produced agreements with different project developers who have agreed to construct new, Southern California generating resources. SCE has entered into a number of contracts, of which five received regulatory approval in the fourth quarter of 2008 and are recorded as derivative instruments. The contracts provide for fixed capacity payments as well as pricing for energy delivered based on a heat rate and contractual operation and maintenance prices. However, due to uncertainty regarding the availability of required emission credits, some of the generating resources may not be constructed and the contracts associated with these resources could therefore terminate, at which time SCE would no longer account for these contracts as derivatives.

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Fair Value of Derivative Instruments

The following table summarizes the gross fair values of commodity derivative instruments (before netting) at March 31, 2009:

In millions	Derivative Assets Short-Term	Derivative Assets Long-Term	Derivative Assets Total	Derivative Liabilities Short-Term	Derivative Liabilities Long-Term	Derivative Liabilities Total
			(Unaudited)			
Non-Trading Activities						
Economic Hedges	$ 130	$ 439	$ 569	$ 252	$ 742	$ 994
Netting and Collateral	(1)		(1)	(111)		(111)
Total	**$ 129**	**$ 439**	**$ 568**	**$ 141**	**$ 742**	**$ 883**

Income Statement Impact of Derivative Instruments

SCE recognizes realized gains and losses on derivative instruments as purchased power expense and recovers these costs from ratepayers. Due to expected future recovery from ratepayers, unrealized gains and losses are deferred and are not recognized as purchased power expense until realized. As a result, realized and unrealized gains and losses do not affect earnings, but may temporarily affect cash flows. The results of derivative activities and related regulatory offsets are recorded in cash flows from operating activities in the consolidated statements of cash flows. Realized losses on economic hedging activities were $98 million and $2 million for the first quarter of 2009 and 2008, respectively. Unrealized gains on economic hedging activities were $333 million and $155 million for the first quarter of 2009 and 2008, respectively.

Contingent Features/Credit Related Exposure

Certain derivative instruments under SCE's power and natural gas trading activities contain margin and collateral requirements. SCE has historically provided collateral in the form of cash and letters of credit for the benefit of counterparties related to the net of accounts payable, accounts receivable, unrealized losses and unrealized gains in connection with derivative activities. 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 margin and collateral requirements 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 as of March 31, 2009, was $112 million, for which SCE has posted collateral of $6 million to its counterparties. If the credit-risk-related contingent features underlying these agreements were triggered on March 31, 2009, SCE would be required to post an additional $2 million of collateral.

Competitive Power Generation

EME uses derivative instruments to reduce EME's exposure to fluctuations in the price of electricity, capacity and fuel, emission allowances and transmission rights which may impact cash flow from its power plant operations. To the extent that EME does not use derivative instruments to hedge these

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price risks, the unhedged portions will be subject to the risks and benefits of spot market price movements. Hedge transactions are primarily entered into using derivative instruments including:

futures contracts cleared on the Intercontinental Trading Exchange and the New York Mercantile Exchange or executed bilaterally with counterparties,

forward sales transactions entered into on a bilateral basis with third parties, including electric utilities, power marketing companies and financial institutions,

full requirements services contracts or load requirements services contracts for the procurement of power for electric utilities' customers, with such services providing for the delivery of a bundled product including, but not limited to, energy, transmission, capacity, and ancillary services, generally for a fixed unit price, and

capacity transactions, including participation in capacity auctions.

The extent to which EME hedges its market price risk depends on several factors. First, EME evaluates over-the-counter market prices to determine if forward market prices are sufficiently attractive compared to the risks associated with the fluctuating spot market. Second, EME evaluates the sufficiency of its credit capacity at EME and Midwest Generation and whether the forward sales markets have sufficient liquidity to enable EME to identify appropriate counterparties for hedge transactions. Hedge transactions entered into by EME are accounted for under SFAS No. 133.

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

SFAS No. 133 sets forth the accounting requirements for cash flow hedges. SFAS No. 133 provides that the effective portion of 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.

Many of the derivative instruments entered into for risk management purposes (also referred to as non-trading purposes) meet the requirements for hedge accounting under SFAS No. 133. However, not all derivative instruments entered into for risk management purposes will qualify for hedge accounting treatment. Furthermore, EME utilizes derivative contracts that are designed to adjust financial and/or physical positions that reduce costs or increase gross margin. Accordingly, risk management positions may not be designated as cash flow hedges and are thus marked to market through current period earnings (derivatives that are entered into for risk management, but which are not designated as cash flow hedges, are referred to as economic hedges).

SFAS No. 133 affects the timing of income recognition, but has no effect on cash flow. To the extent that income varies under SFAS No. 133 from accrual accounting (i.e., revenue recognition based on the settlement of transactions), EME records unrealized gains or losses. EME classifies unrealized gains and losses from energy contracts in competitive power generation revenues. In addition, the results of

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derivative activities are recorded in cash flows from operating activities in the consolidated statements of cash flows.

Derivative instruments that are utilized for trading purposes are measured at fair value and included in the balance sheet as derivative assets or liabilities. In the absence of quoted market prices, derivative instruments are valued at fair value as determined through the methodology outlined in Note 10 Fair Value Measurements. Resulting gains and losses are recognized in competitive power generation revenues in the accompanying consolidated income statements in the period of change in accordance with EITF No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities."

Where EME's derivative instruments are subject to a master netting agreement and the criteria of FASB Interpretation (FIN) No. 39 "Offsetting of Amounts Related to Certain Contracts" are met, EME presents its derivative assets and liabilities on a net basis in its balance sheet.

Notional Volumes of Derivative Instruments

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

				Hedging Activities		
Commodity	**Instrument**	**Classification**	**Unit of Measure**	**Cash Flow Hedges**	**Economic Hedges**	**Trading Activities**
Electricity	Forwards	Sales	GWh	19,879[1]	23,361[3]	23,034
Electricity	Forwards	Purchases	GWh		22,005[3]	23,511
Electricity	Capacity	Sales	MW-Day (in thousands)	315[2]		574,225[2]
Electricity	Capacity	Purchases	MW-Day (in thousands)	288[2]		707,625[2]
Electricity	Congestion	Sales	GWh		136[4]	5,049[4]
Electricity	Congestion	Purchases	GWh		1,041[4]	105,917[4]
Natural gas	Forwards	Sales	Bcf		9.2	28.8
Natural gas	Forwards	Purchases	Bcf			28.0
Fuel oil	Forwards	Sales	Barrels			55,000
Fuel oil	Forwards	Purchases	Barrels		25,200,000	55,000

(1) EME's hedge products include forward and futures contracts that qualify for hedge accounting under SFAS No. 133. This category excludes power contracts for the Illinois Plants which meet the normal sales and purchase exception under SFAS No. 133 and are accounted for on the accrual method.

(2) EME's hedge transactions for capacity result from bilateral trades prior to PJM RPM auctions. Capacity sold in the PJM RPM auction is not accounted for as a derivative under SFAS No. 133.

(3) EME also entered into transactions that adjust financial and physical positions, or day-ahead and real-time positions to reduce costs or increase gross margin. These positions largely offset each other. The net sales positions of these categories are primarily related to hedge transactions that are not designated as cash flow hedges under SFAS No. 133.

(4) Congestion contracts are FTRs, transmission congestion contracts or CRRs. 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.

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Fair Value of Derivative Instruments

The following table summarizes the gross fair value of commodity derivative instruments at March 31, 2009:

In millions	Derivative Assets Short-term	Derivative Assets Long-term	Derivative Assets Subtotal	Derivative Liabilities Short-term	Derivative Liabilities Long-term	Derivative Liabilities Subtotal	Net Assets
Non-trading activities							
Cash flow hedges	$ 372	$ 203	$ 575	$ 17	$ 15	$ 32	$ 543
Economic hedges	282	122	404	276	113	389	15
Trading activities	540	192	732	507	112	619	113
	$ 1,194	$ 517	$ 1,711	$ 800	$ 240	$ 1,040	$ 671
Netting and collateral received	(978)	(351)	(1,329)	(771)	(238)	(1,009)	(320)
Total	**$ 216**	**$ 166**	**$ 382**	**$ 29**	**$ 2**	**$ 31**	**$ 351**

Income Statement Impact of Derivative Instruments

The following table provides the activity of accumulated other comprehensive income for the three months ended March 31, 2009, containing the information about the changes in the fair value of cash flow hedges and reclassification from accumulated other comprehensive income into results of operations:

In millions	Cash Flow Hedge Activity[(1)]	Income Statement Location
Accumulated other comprehensive income derivative gain at December 31, 2008	$ 398	
Effective portion of changes in fair value	249	
Reclassification from accumulated other comprehensive income to net income	(81)	Competitive power generation revenues[(2)]
Accumulated other comprehensive income derivative gain at March 31, 2009	**$ 566**	

(1) Unrealized derivative gains are before income taxes. The after-tax amounts recorded in accumulated other comprehensive income at March 31, 2009 and December 31, 2008 were $342 million and $240 million, respectively.

(2) Represents reclassification of unrealized gains to competitive power generation revenues.

Under SFAS No. 133, the portion of a cash flow hedge that does not offset the change in the value of the transaction being hedged, which is commonly referred to as the ineffective portion, is immediately recognized in earnings. EME recorded net losses of none and $13 million during the first quarters of 2009 and 2008, respectively, representing the amount of cash flow hedge ineffectiveness and are reflected in competitive power generation revenues in the income statement.

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The effect of realized and unrealized gains from derivative instruments used for economic hedging and trading purposes on the consolidated statement of income for the period ended March 31, 2009 is presented below (Unaudited):

(In millions)

Commodity	**Location**	**Amount**
Economic hedges	Competitive power generation revenue	$ 14
Trading activities	Competitive power generation revenue	10

Contingent Features/Credit Related Exposure

Certain derivative instruments contain margin and collateral deposit requirements. Since EME's credit ratings are below investment grade, EME has historically provided collateral in the form of cash and letters of credit for the benefit of counterparties related to the net of accounts payable, accounts receivable, unrealized losses and unrealized gains in connection with derivative activities. Certain derivative contracts do not require margining, but contain provisions that require EME or Midwest Generation to comply with the terms and conditions of their respective credit facilities. The credit facilities each contain financial covenants. Some hedge contracts include provisions related to a change in control or material adverse effect resulting from amendments or modifications to the related credit facility. Failure by EME or Midwest Generation to comply with these provisions may result in a termination event under the hedge contracts, enabling the counterparties to terminate and liquidate all outstanding transactions and demand immediate payment of amounts owed to them. EMMT also has hedge contracts that do not require margining, but contain the right of each party to request additional credit support in the form of adequate assurance of performance in the case of an adverse development affecting the other party. The aggregate fair value of all derivative instruments with credit-risk-related contingent features is in an asset position on March 31, 2009 and, accordingly, the contingent features described above do not currently have a liquidity exposure. Future increases in power prices could expose EME or Midwest Generation to termination payments or additional collateral postings under the contingent features described above.

Financial Services and Other

Edison Capital has a foreign currency swap with a notional amount of 56 million British pounds to hedge both the interest rate and related long-term debt denominated in a foreign currency. At March 31, 2009, the gross fair value of this cash flow hedge was $34 million and is reported as a long-term derivative on the consolidated balance sheet. For the quarter ended March 31, 2009, the effective portion of the changes in the fair value of this derivative was less than $1 million and the reclassification from "accumulated other comprehensive income" into income was also less than $1 million.

Note 3. Liabilities and Lines of Credit

Long-Term Debt

In March 2009, SCE issued $500 million of 6.05% and $250 million of 4.15% first and refunding mortgage bonds due in 2039 and 2014, respectively. The bond proceeds are to be used for general corporate purposes.

In February 2009, SCE repaid $150 million of its first and refunding mortgage bonds. In March 2009, SCE purchased two issues of its tax-exempt pollution control bonds totaling $219 million and converted the issues to a variable rate structure. SCE continues to hold the bonds which remain outstanding and have not been retired or cancelled.

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Short-Term Debt

SCE short-term debt is generally used to finance fuel inventories, balancing account undercollections and general, temporary cash requirements including power-purchase payments. At March 31, 2009, outstanding short-term debt was $1.56 billion at a weighted-average interest rate of 0.66%. This short-term debt was supported by a $2.5 billion credit line. See below in "Credit Agreements."

At December 31, 2008, Edison International (parent) had $250 million of short-term debt outstanding under its $1.5 billion credit facility. These borrowings were repaid in the first quarter of 2009.

Credit Agreements

On March 17, 2009, SCE entered into a credit agreement with several lenders. The agreement provides for a $500 million 364-day revolving credit facility. The additional liquidity provided by the facility will be used to support SCE's ongoing power procurement-related needs.

The following table summarizes the status of the credit facilities at March 31, 2009:

In millions	**SCE**	**EMG**	**Edison International (parent)**
		(Unaudited)	
Commitment	$ 3,000	$ 1,100	$ 1,500
Less: Unfunded commitment from Lehman Brothers subsidiary	(81)	(36)	(74)
	2,919	1,064	1,426
Outstanding borrowings	(1,558)	(826)	
Outstanding letters of credit	(137)	(128)	
Amount available	**$ 1,224**	**$ 110**	**$ 1,426**

Note 4. Income Taxes

Edison International's composite federal and state statutory income tax rate was approximately 40% (net of the federal benefit for state income taxes) for both periods presented. The effective tax rates of 33% and 35% for the three months ended March 31, 2009 and 2008, respectively, were lower compared to the statutory rate primarily due to property related flow through tax deductions at SCE, production tax credits at EME, and low income housing credits at Edison Capital. The effective tax rate of 33% was lower compared to the same period in 2008 primarily due to a decrease in pre-tax income combined with an increase in production tax credits at EME.

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Accounting for Uncertainty in Income Taxes

The following table provides a reconciliation of unrecognized tax benefits from December 31 to March 31 for 2009 and 2008:

In millions	**2009**	**2008**
	(Unaudited)	
Balance at beginning of period	**$ 2,237**	$ 2,114
Tax positions taken during the current year		
Increases	**3**	78
Decreases		
Tax positions taken during a prior year		
Increases	**8**	20
Decreases	**(107)**	(63)
Decreases for settlements during the period		
Reductions for lapses of applicable statute of limitations		
Balance at March 31	**$ 2,141**	$ 2,149

The unrecognized tax benefits in the table above reflect affirmative claims related to timing differences of $1.5 billion at March 31, 2009 and December 31, 2008, that have been claimed on amended tax returns, but have not met the recognition threshold pursuant to FIN 48 and have been denied by the IRS as part of their examinations. These affirmative claims remain unpaid by the IRS and no receivable has been recorded. These affirmative claims as well as other uncertain tax positions are expected to be settled in the next twelve months with the consummation of the Global Settlement discussed below. As a result, the unrecognized tax benefits will be reduced by approximately $1.4 billion.

As of March 31, 2009 and December 31, 2008, respectively, if recognized, $202 million and $210 million of the unrecognized tax benefits would impact the effective tax rate.

Accrued Interest and Penalties

The total amounts of accrued interest and penalties related to Edison International's income tax reserve were $206 million and $200 million as of March 31, 2009 and December 31, 2008, respectively. For the three months ended March 31, 2009, and 2008, respectively, $4 million and $8 million of after-tax interest expense was recognized and included in income tax expense.

Tax Years Subject to Examination

Edison International's federal income tax returns are subject to examination by the IRS for tax years 2003 to present. Consummation of the Global Settlement, discussed below, effectively closed the examination for tax years 1986 2002 and resolved federal tax disputes related to Edison Capital's cross-border, leveraged leases in their entirety.

In addition to the IRS audits, Edison International's California and other state income tax returns are open for examination by the California Franchise Tax Board and the other state tax authorities for tax years 1986 to present. The Franchise Tax Board has substantially completed its examination of all tax years through 2002 and is currently awaiting resolution of the IRS audit before finalizing the audit for these tax years.

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Global Settlement

As disclosed before, Edison International and the IRS had previously negotiated the material terms of a Global Settlement which, upon consummation, would resolve federal tax disputes related to Edison Capital's cross-border, leveraged leases in their entirety, and all other outstanding federal tax disputes and affirmative claims for tax years 1986 through 2002. Also, as previously disclosed, certain aspects of the Global Settlement were subject to review by the Staff of the Joint Committee on Taxation, a committee of the United States Congress (the "Joint Committee").

In April 2009, Edison International was advised by the IRS that the Joint Committee completed its review, and did not recommend any adjustments to the terms of the Global Settlement submitted for review. Pursuant to the Global Settlement, Edison Capital subsequently terminated its interests in the cross-border leases, and Edison International and the IRS finalized the Global Settlement on May 5, 2009.

The Global Settlement and termination of the Edison Capital leases will have the following impacts:

- Edison International expects to record a consolidated after-tax earnings charge of approximately $225 million to $300 million through the second quarter of 2009 and expects an overall positive cash impact of approximately $325 million to $400 million. These impacts are inclusive of the items discussed further below.

- It will resolve all federal income tax disputes related to Edison Capital's cross border leases through 2009. Termination of the cross border leases and consummation of the Global Settlement will result in an after-tax earnings charge at Edison Capital of approximately $550 million to $600 million through the second quarter of 2009. Edison Capital's net cash outflow over time will be approximately $250 million to $300 million. The proceeds received in the second quarter of 2009 by Edison Capital from the termination of its cross border leases, along with prior tax deposits and other cash, will be used to fund its tax and other obligations.

- It will resolve all federal income tax disputes and affirmative claims related to Southern California Edison through tax year 2002, which primarily included the settlement of two outstanding affirmative claims. The first claim related to tax timing differences associated with the taxation of balancing account overcollections, and the second claim related to tax timing differences associated with the proceeds received in consideration for granting third-party access to Southern California Edison's transmission and distribution system as part of California's deregulation process. Since both of these claims create tax timing benefits only, the settlement results in a payment of interest by the IRS for prior tax overpayments, but will not result in a permanent reduction in Edison International's federal income tax liability. As a result of the Global Settlement, Southern California Edison expects to record after-tax earnings of approximately $275 million to $300 million in the second quarter of 2009. As a result of the Global Settlement, SCE expects a positive cash impact of approximately $625 million to $650 million over time, including prior tax deposits of approximately $200 million.

- All other federal tax disputes involving the Edison International consolidated group for tax years 1986 2002 are expected to result in positive earnings and cash impacts.

As a consequence of the Global Settlement lease terminations, Edison Capital may be required to pay outstanding medium-term loans in the amount of $100 million (at March 31, 2009) and approximately $20 million at March 31, 2009 under guarantees in certain affordable housing projects. Edison International does not expect such payments to have a material adverse impact on its results of operations, financial position, or cash flows.

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Edison International intends to file amended state income tax returns reflecting the impacts of the Global Settlement. Resolution with state tax authorities of the issues included in the Global Settlement will require a final settlement with such authorities and the cash and earnings impacts described above reflect the expected state income tax impact of the issues addressed in the Global Settlement with the IRS.

Note 5. Compensation and Benefits Plans

Pension Plans

As of March 31, 2009, Edison International had made less than $1 million in contributions related to 2008 and $14 million related to 2009 and estimates to make $36 million of additional contributions in the last nine months of 2009.

Net pension cost recognized is calculated under the actuarial method used for ratemaking. The difference between pension costs calculated for accounting and ratemaking is deferred.

Expense components are:

	Three Months Ended March 31,	
In millions	**2009**	**2008**
	(Unaudited)	
Service cost	**$ 32**	$ 32
Interest cost	**52**	50
Expected return on plan assets	**(42)**	(65)
Amortization of prior service cost	**4**	4
Amortization of net loss	**14**	
Expense under accounting standards	**60**	21
Regulatory adjustment deferred	**(37)**	
Total expense recognized	**$ 23**	$ 21

Postretirement Benefits Other Than Pensions

As of March 31, 2009, Edison International had made no contributions related to 2008 and $4 million related to 2009 and estimates to make $121 million of additional contributions in the last nine months of 2009.

Expense components are:

	Three Months Ended March 31,	
In millions	**2009**	**2008**
	(Unaudited)	
Service cost	**$ 11**	$ 12
Interest cost	**36**	35
Expected return on plan assets	**(21)**	(31)
Amortization of prior service cost (credit)	**(8)**	(8)
Amortization of net loss	**16**	4
Total expense recognized	**$ 34**	$ 12

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Stock-Based Compensation

During the first quarter of 2009, Edison International granted its 2009 stock-based compensation awards, which included stock options, performance shares, deferred stock units and restricted stock units. Total stock-based compensation expense (reflected in the caption "Other operation and maintenance" on the consolidated statements of income) was $5 million and $7 million for the three months ended March 31, 2009 and 2008, respectively. The income tax benefit recognized in the consolidated statements of income was $2 million and $3 million for the three months ended March 31, 2009 and 2008, respectively. Total stock-based compensation cost capitalized was $1 million for the three months ended March 31, 2008. Consistent with SCE's 2009 GRC, no stock-based compensation was capitalized in 2009.

Stock Options

A summary of the status of Edison International stock options is as follows:

	Stock Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value
		(Unaudited)		
Outstanding at December 31, 2008	13,441,835	$ 34.22		
Granted	4,862,582	$ 24.84		
Expired	(28,392)	$ 40.51		
Forfeited	(6,076)	$ 47.92		
Exercised	(135,499)	$ 24.73		
Outstanding at March 31, 2009	**18,134,450**	**$ 31.76**	**7.07**	
Vested and expected to vest at March 31, 2009	17,391,466	$ 31.72	6.98	$76,120,664
Exercisable at March 31, 2009	**10,159,096**	**$ 30.27**	**5.43**	**$52,740,708**

Stock options granted in 2008 and 2009 do not accrue dividend equivalents.

The amount of cash used to settle stock options exercised was $4 million and $13 million for the three months ended March 31, 2009 and 2008, respectively. Cash received from options exercised was $3 million and $7 million for the three months ended March 31, 2009 and 2008, respectively. The estimated tax benefit from options exercised was less than $1 million and $3 million for the three months ended March 31, 2009 and 2008, respectively.

The following is a summary of the status of Edison International nonvested performance shares classified as equity awards:

	Performance Shares	Weighted-Average Grant-Date Fair Value
	(Unaudited)	
Nonvested at December 31, 2008	175,177	$ 49.45
Granted	173,304	$ 20.84
Forfeited	(328)	$ 58.35
Paid out		$
Nonvested at March 31, 2009	**348,153**	**$ 35.20**

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The following is a summary of the status of Edison International nonvested performance shares classified as liability awards (the current portion is reflected in the caption "Other current liabilities" and the long-term portion is reflected in "Pensions and benefits" on the consolidated balance sheets):

	Performance Shares	Weighted-Average Fair Value
	(Unaudited)	
Nonvested at December 31, 2008	175,177	
Granted	173,304	
Forfeited	(328)	
Paid out		
Nonvested at March 31, 2009	**348,153**	**$ 17.45**

Note 6. Commitments and Contingencies

The following is an update to Edison International's commitments and contingencies. See Note 6 of "Notes to Consolidated Financial Statements" included in Edison International's 2008 Annual Report on Form 10-K for a detailed discussion.

Lease Commitments

Edison International has (1) operating leases for power contracts and (2) other operating leases for office space, vehicles, property and other equipment (with varying terms, provisions and expiration dates). For additional discussion of these lease commitments, see Note 1 of "Notes to Consolidated Financial Statements" included in Edison International's 2008 Annual Report on Form 10-K. The following are estimated remaining commitments (the majority of other operating leases are related to EME's long-term leases for the Illinois power facilities and Homer City facilities) for noncancelable operating leases:

In millions	Power Contracts Operating Leases	Other Operating Leases
Year ending December 31,		
2009 (remaining nine months)	$ 570	$ 301
2010	624	401
2011	458	376
2012	355	366
2013	349	355
Thereafter	1,998	2,163
Total	**$ 4,354**	**$ 3,962**

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

Operating lease expense was $110 million for both the three month periods ended March 31, 2009 and 2008.

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Other Commitments

At March 31, 2009, EME's subsidiaries had firm commitments to spend approximately $106 million during the remainder of 2009 and $12 million in 2010 on capital and construction expenditures. The majority of these expenditures relate to the construction of wind projects and non-environmental improvements at both the Illinois Plants and the Homer City facilities. These expenditures are planned to be financed by cash on hand and cash generated from operations.

EME has entered into various turbine supply agreements with vendors to support its wind development efforts. At March 31, 2009, EME had secured the rights to 484 wind turbines (942 MW) for use in future projects for an aggregate purchase price of $1.2 billion, with remaining commitments of $667 million in 2009 and $240 million in 2010. Turbine payments scheduled during the first quarter of 2009 were deferred by agreement with certain suppliers. EME and Suzlon Wind Energy Corporation are discussing a number of contractual performance matters and related turbine payments. With respect to turbine payments scheduled for the balance of 2009, EME has continued to engage in discussions with each of the turbine suppliers to defer the payment of the remaining commitments under each of the turbine supply agreements. At March 31, 2009, EME had recorded wind turbine deposits of $336 million, included in other long-term assets on its consolidated balance sheet. Under certain of these agreements, EME may terminate the purchase of individual turbines, or groups of turbines, for convenience. If EME terminated one or more turbine supply agreements, it would result in a charge related to such termination.

At March 31, 2009, Midwest Generation and EME Homer City had fuel purchase commitments with various third-party suppliers for the purchase of coal. Based on the contract provisions, which consist of fixed prices subject to adjustment clauses, these minimum commitments are currently estimated to aggregate $535 million, summarized as follows: remainder of 2009 $360 million, 2010 $165 million, and 2011 $10 million.

Guarantees and Indemnities

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

Tax Indemnity Agreements

In connection with the sale-leaseback transactions related to the Homer City facilities in Pennsylvania, the Powerton and Joliet Stations in Illinois and, previously, the Collins Station in Illinois, EME and several of its subsidiaries entered into tax indemnity agreements. Although the Collins Station lease terminated in April 2004, Midwest Generation's tax indemnity agreement with the former lease equity investor is still in effect. Under these tax indemnity agreements, these entities agreed to indemnify the lessors in the sale-leaseback transactions for specified adverse tax consequences that could result in certain situations set forth in each tax indemnity agreement, including specified defaults under the respective leases. The potential indemnity obligations under these tax indemnity agreements could be significant. Due to the nature of these potential obligations, EME cannot determine a maximum potential liability which would be triggered by a valid claim from the lessors. EME has not recorded a liability related to these indemnities.

Indemnities Provided as Part of the Acquisition of the Illinois Plants

In connection with the acquisition of the Illinois Plants, EME agreed to indemnify Commonwealth Edison with respect to specified environmental liabilities before and after December 15, 1999, the date of sale. The indemnification claims are reduced by any insurance proceeds and tax benefits related to

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such claims and are subject to a requirement that Commonwealth Edison takes all reasonable steps to mitigate losses related to any such indemnification claim. Due to the nature of the obligation under this indemnity, a maximum potential liability cannot be determined. This indemnification for environmental liabilities is not limited in term and would be triggered by a valid claim from Commonwealth Edison. Commonwealth Edison has advised EME that Commonwealth Edison believes it is entitled to indemnification for all liabilities, costs, and expenses that it may be required to bear as a result of the NOV discussed below under " Contingencies Midwest Generation New Source Review Notice of Violation" and potential litigation by private groups related to the NOV. Except as discussed below, EME has not recorded a liability related to the environmental indemnity specified in the acquisition agreement.

Midwest Generation entered into a supplemental agreement with Commonwealth Edison and Exelon Generation Company, LLC on February 20, 2003 to resolve a dispute regarding interpretation of its reimbursement obligation for asbestos claims under the environmental indemnities set forth in the Asset Sale Agreement. Under this supplemental agreement, Midwest Generation agreed to reimburse Commonwealth Edison and Exelon Generation for 50% of specific asbestos claims pending as of February 2003 and related expenses less recovery of insurance costs, and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement. As a general matter, Commonwealth Edison and Midwest Generation apportion responsibility for future asbestos-related claims based upon the number of exposure sites that are Commonwealth Edison locations or Midwest Generation locations. The obligations under this agreement are not subject to a maximum liability. The supplemental agreement had an initial five-year term with an automatic renewal provision for subsequent one-year terms (subject to the right of either party to terminate); pursuant to the automatic renewal provision, it has been extended until February 2010. There were approximately 238 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed at March 31, 2009. Midwest Generation had recorded a $52 million liability at March 31, 2009 related to this matter.

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

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

In connection with the acquisition of the Homer City facilities, EME Homer City agreed to indemnify the sellers with respect to specific environmental liabilities before and after the date of sale. Payments would be triggered under this indemnity by a valid claim from the sellers. EME guaranteed the obligations of EME Homer City. Due to the nature of the obligation under this indemnity provision, it is not subject to a maximum potential liability and does not have an expiration date. For discussion of the NOV received by EME Homer City and associated indemnity claims, see " Contingencies EME Homer City New Source Review Notice of Violation." EME has not recorded a liability related to this indemnity.

Indemnities Provided under Asset Sale Agreements

The asset sale agreements for the sale of EME's international assets contain indemnities from EME to the purchasers, including indemnification for taxes imposed with respect to operations of the assets prior to the sale and for pre-closing environmental liabilities. Not all indemnities under the asset sale agreements have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. At March 31, 2009, EME had recorded a liability of $89 million (of which $49 million is classified as a current liability) related to these matters.

In connection with the sale of various domestic assets, EME has from time to time provided indemnities to the purchasers for taxes imposed with respect to operations of the asset prior to the sale. EME has also provided indemnities to purchasers for items specified in each agreement (for example, specific pre-existing litigation matters and/or environmental conditions). Due to the nature of the obligations under these indemnity agreements, a maximum potential liability cannot be determined. Not all indemnities under the asset sale agreements have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. At March 31, 2009, EME had recorded a liability of $3 million related to these matters.

Indemnity Provided as Part of the Acquisition of Mountainview

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

Mountainview Filter Cake Indemnity

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

Other Edison International Indemnities

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

Contingencies

In addition to the matters disclosed in these Notes, Edison International is involved in other legal, tax and regulatory proceedings before various courts and governmental agencies regarding matters arising in the ordinary course of business. Edison International believes the outcome of these other proceedings will not materially affect its results of operations or liquidity.

Environmental Remediation

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

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

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

As of March 31, 2009, Edison International's recorded estimated minimum liability to remediate its 46 identified sites at SCE (24 sites) and EME (22 sites primarily related to Midwest Generation) was $44 million, $41 million of which was related to SCE including $8 million related to San Onofre. This remediation liability is undiscounted. Edison International's other subsidiaries have no identified remediation sites. The ultimate costs to clean up Edison International's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. Edison International believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $173 million, all of which is related to SCE. The upper limit of this range of costs was estimated using assumptions least favorable to Edison International among a range of reasonably possible outcomes. In addition to its identified sites (sites in which the upper end of the range of costs is at least $1 million), SCE also has 30 immaterial sites whose total liability ranges from $3 million (the recorded minimum liability) to $9 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $31 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $40 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

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

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $11 million to $30 million. Recorded costs for the 12 months ended March 31, 2009 and 2008, respectively, were $29 million and $23 million.

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

Federal and State Income Taxes

Edison International remains subject to examination by the IRS for tax years 2003 to present. As discussed in the section "Global Settlement" in Note 4, the Global Settlement was finalized on May 5, 2009 and effectively closed the examination for tax years 1986 2002 and resolved federal tax disputes related to Edison Capital's cross-border, leveraged leases in their entirety.

2009 FERC Rate Case

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

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

FERC Transmission Incentives

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

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

In August 2008, the CPUC filed an appeal of the FERC incentives order at the DC Circuit Court of Appeals. The Court issued a ruling on November 6, 2008, accepting the CPUC's request that the Court refrain from ruling on the CPUC's appeal until a final FERC order is issued in the 2008 CWIP case.

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FERC Construction Work in Progress Mechanism

2008 CWIP

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

2009 CWIP

In December 2008, the FERC approved SCE's CWIP rate adjustment reducing its CWIP revenue requirement from $45 million to $39 million, effective on January 1, 2009, subject to refund as well as subject to the outcome of the pending 2008 FERC CWIP proceeding.

EME Homer City New Source Review Notice of Violation

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

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

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

Four Corners CPUC Emissions Performance Standard Ruling

The emission performance standards adopted by the CPUC and CEC pursuant to SB 1368 prohibit SCE and other California load-serving entities from entering into long-term financial commitments with generators that do not meet the emission performance standards, which would include most coal-fired plants. In January 2008, SCE filed a petition with the CPUC seeking clarification that the emission performance standard would not apply to capital expenditures required by existing agreements among the owners at Four Corners. The CPUC issued a proposed decision finding that the emission performance standard was not intended to apply to capital expenditures at Four Corners requested by SCE in its GRC for the period 2007 2011. In October 2008, the Assigned Commissioner and Administrative Law Judge issued a ruling withdrawing the proposed decision and seeking additional comment on whether the finding in the proposed decision should be changed and whether SCE should

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be allowed to recover such capital expenditures. SCE estimates that its share of capital expenditures approved by the owners at Four Corners since the GHG emission performance standard decision was issued in January 2007 is approximately $43 million, of which approximately $10 million had been expended through March 31, 2009. The ruling also directs SCE to explain why certain information was not included in its petition and why the failure to include such information should not be considered misleading in violation of CPUC rules. SCE cannot predict whether any amounts will be disallowed or if any penalties will be imposed.

ISO Disputed Charges

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

Leveraged Lease Investments

At March 31, 2009, Edison Capital had a net leveraged lease investment, before deferred taxes, of $50 million in three aircraft leased to American Airlines. American Airlines reported net losses in the first quarter of 2009 and previously reported losses for 2008. A default in the leveraged lease by American Airlines could result in a loss of some or all of Edison Capital's lease investment. At March 31, 2009, American Airlines was current in its lease payments to Edison Capital.

Midwest Generation New Source Review Notice of Violation

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

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

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

Navajo Nation Litigation

The Navajo Nation filed a complaint in June 1999 against SCE, among other defendants, arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal RICO statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentations by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal supplied to Mohave. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion. In March 2001, the Hopi Tribe was permitted to intervene as an additional plaintiff but has not yet identified a specific amount of damages claimed. The case was stayed at the request of the parties in October 2004, but was reinstated to the active calendar in March 2008. In April 2009, in a related case filed in December 1993 against the U.S. Government, the U.S. Supreme Court found that the Navajo Nation did not have a claim for compensation.

SCE cannot predict the outcome of the Tribes' complaints against SCE or the ultimate impact of the April 2009 U.S. Supreme Court decision on these complaints.

Nuclear Insurance

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

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

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. A

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mutual insurance company owned by utilities with nuclear facilities issues these policies. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to approximately $45 million per year. Insurance premiums are charged to operating expense.

Procurement of Renewable Resources

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

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

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

RPM Buyers' Complaint

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

Spent Nuclear Fuel

Under federal law, the DOE is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE did not meet its contractual obligation to begin acceptance of spent nuclear fuel by January 31, 1998. It is not certain when the DOE will begin accepting spent nuclear fuel from San Onofre or other nuclear power plants. Extended delays by the DOE have led to the construction of costly alternatives and associated siting and environmental issues. SCE has paid the DOE the required one-time fee applicable to nuclear generation at San Onofre (approximately $24 million, plus interest). SCE has also been paying a required quarterly fee equal to 0.1¢ per-kWh of nuclear-generated electricity sold after April 6, 1983. On January 29, 2004, SCE, as operating agent, filed a complaint against the DOE in the United States Court of Federal Claims seeking damages for the DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre and the trial began on April 20, 2009.

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

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

Note 7. Consolidated Statement of Changes in Equity

Pursuant to SFAS No. 160, Edison International is providing a consolidated statement of changes in equity as follows:

	Equity Attributable to Edison International				Noncontrolling Interests		
In millions	Common Stock	Accumulated Other Comprehensive Income	Retained Earnings	Subtotal	Other	Preferred and Preference Stock	Total Equity
			(Unaudited)				
Balance at December 31, 2008	$ 2,272	$ 167	$ 7,078	$ 9,517	$ 285	$ 907	$ 10,709
Net income			250	250	6	13	269
Other comprehensive income		104		104			104
Common stock dividends declared ($ 0.31 per share)			(101)	(101)			(101)
Dividends, distributions to noncontrolling interests and other					(14)	(13)	(27)
Shares purchased for stock-based compensation			(4)	(4)			(4)
Proceeds from stock option exercises			3	3			3
Noncash stock-based compensation and other	4		(7)	(3)			(3)
Excess tax benefits related to stock-based awards	2			2			2
Balance at March 31, 2009	**$ 2,278**	**$ 271**	**$ 7,219**	**$ 9,768**	**$ 277**	**$ 907**	**$ 10,952**

Note 8. Accumulated Other Comprehensive Income

Edison International's accumulated other comprehensive income consists of:

In millions	Unrealized Gains on Cash Flow Hedges	Foreign Currency Translation Adjustment	Pension and PBOP Net Gain (Loss)	Pension and PBOP Prior Service Cost	Accumulated Other Comprehensive Income
			(Unaudited)		
Balance at December 31, 2008	$ 240	$ (4)	$ (70)	$ 1	$ 167
Current period change	102		2		104
Balance at March 31, 2009	**$ 342**	**$ (4)**	**$ (68)**	**$ 1**	**$ 271**

Unrealized gains on cash flow hedges, net of tax, at March 31, 2009, included unrealized gains on commodity hedges related to Midwest Generation and EME Homer City futures and forward electricity contracts that qualify for hedge accounting. These gains arise because current forecasts of future electricity prices in these markets are lower than the contract prices. As EME's hedged positions for continuing operations are realized, $229 million, after tax, of the net unrealized gains on cash flow hedges at March 31, 2009 are expected to be reclassified into earnings during the next 12 months.

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Management expects that reclassification of net unrealized gains will increase energy revenue recognized at market prices. Actual amounts ultimately reclassified into earnings over the next 12 months could vary materially from this estimated amount as a result of changes in market conditions. The maximum period over which a cash flow hedge is designated is through December 31, 2011.

Note 9. Supplemental Cash Flows Information

Edison International's supplemental cash flows information is:

	Three Months Ended March 31,	
In millions	**2009**	**2008**
	(Unaudited)	
Cash payments (receipts) for interest and taxes:		
Interest net of amounts capitalized	**$ 137**	$ 139
Tax payments (receipts)	**$ (33)**	$ 6
Noncash investing and financing activities:		
Dividends declared but not paid:		
Common stock	**$ 101**	$ 99
Preferred and preference stock of utility not subject to mandatory redemption	**$ 8**	$ 8

Note 10. Fair Value Measurements

SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (referred to as an "exit price" in SFAS No. 157). SFAS No. 157 clarifies that a fair value measurement for a liability should reflect the entity's non-performance risk. In addition, SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets and liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy under SFAS No. 157 are:

Level 1 Unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets and liabilities;

Level 2 Pricing inputs include quoted prices for similar assets and liabilities in active markets and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the derivative instrument; and

Level 3 Prices or valuations that require inputs that are both significant to the fair value measurements and unobservable.

Edison International's assets and liabilities carried at fair value primarily consist of derivative contracts, SCE nuclear decommissioning trust investments and money market funds. Derivative contracts primarily relate to power and gas and include contracts for forward physical sales and purchases, options and forward price swaps which settle only on a financial basis (including futures contracts). Derivative contracts can be exchange traded or over-the-counter traded.

The fair value of derivative contracts takes into account quoted market prices, time value of money, volatility of the underlying commodities and other factors. Derivatives that are exchange traded in active markets for identical assets or liabilities are classified as Level 1. The majority of EME's derivative contracts used for hedging purposes are based on forward market prices in active markets (PJM West Hub, Northern Illinois Hub peak and AEP/Dayton) adjusted for nonperformance risks. EME obtains forward market prices from traded exchanges (ICE Futures U.S. or New York Mercantile Exchange) and available broker quotes. Then, EME selects a primary source that best represents traded activity for each market to develop observable forward market prices in determining the fair value of these positions. Broker quotes or prices from exchanges are used to validate and corroborate the primary source. These price quotations reflect mid-market prices (average of bid and ask) and are obtained from sources that EME believes to provide the most liquid market for the commodity. EME considers broker quotes to be observable when corroborated with other information which may include a combination of prices from exchanges, other brokers and comparison to executed trades. The majority of the fair value of EME's derivative contracts determined in this manner are classified as Level 2. SCE's Level 2 derivatives primarily consist of financial natural gas swaps, fixed float swaps, and natural gas physical trades for which SCE obtains the applicable Henry Hub and basis forward market prices from the New York Mercantile Exchange and Intercontinental Exchange.

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

Level 3 also includes derivatives that trade infrequently (such as financial transmission rights, FTRs and CRRs in the California market and over-the-counter derivatives at illiquid locations), derivatives with counterparties that have significant nonperformance risks as discussed below and long-term power agreements. For illiquid financial transmission rights, FTRs and CRRs, Edison International reviews objective criteria related to system congestion and other underlying drivers and adjusts fair value when Edison International concludes a change in objective criteria would result in a new valuation that better reflects the fair value.

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

In assessing nonperformance risks, Edison International 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. At March 31, 2009, Edison International reduced the fair value of derivative assets and derivative liabilities for nonperformance risks by $26 million and $83 million, respectively.

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Investments in money market funds are generally classified as Level 1 as fair value is determined by observable market prices (unadjusted) in active markets. In 2008, EME had invested $20 million in the Reserve Primary Fund (a money market fund). The Reserve incurred a loss related to debt securities of Lehman Brothers Holdings and has announced liquidation of the Reserve. EME reduced the fair value of the investment by $1 million and transferred the remaining balance into Level 3 during the third quarter of 2008 as observable market prices were not available. EME subsequently received $17 million ($16 million and $1 million in 2008 and 2009, respectively) in settlements resulting in the ending balance of $2 million at March 31, 2009 classified in Level 3.

The SCE nuclear decommissioning trust investments include equity securities, U.S. treasury securities and other fixed-income securities. Equity and treasury securities are classified as Level 1 as fair value is determined by observable market prices in active or highly liquid and transparent markets. The remaining fixed-income securities are classified as Level 2. The fair value of these financial instruments is based on evaluated prices that reflect significant observable market information such as reported trades, actual trade information of similar securities, benchmark yields, broker/dealer quotes, issuer spreads, bids, offers and relevant credit information.

The following table sets forth assets and liabilities that were accounted for at fair value as of March 31, 2009 by level within the fair value hierarchy.

In millions	**Level 1**	**Level 2**	**Level 3**	**Netting and collateral**[(1)]	**Total**
			(Unaudited)		
Assets at Fair Value					
Money market funds[(2)]	$ 3,248	$	$ 2	$	$ 3,250
Derivative contracts	10	579	851	(490)	950
Nuclear decommissioning trusts[(3)]	1,389	1,011			2,400
Long-term disability plan	7				7
Total assets[(4)]	4,654	1,590	853	(490)	6,607
Liabilities at Fair Value					
Derivative contracts	(1)	(517)	(710)	280	(948)
Net assets (liabilities)	**$ 4,653**	**$ 1,073**	**$ 143**	**$ (210)**	**$ 5,659**

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The following table sets forth assets and liabilities that were accounted for at fair value as of December 31, 2008 by level within the fair value hierarchy:

In millions	Level 1	Level 2	Level 3	Netting and Collateral[1]	Total
			(Unaudited)		
Assets at Fair Value					
Money market funds[2]	$ 3,543	$	$ 3	$	$ 3,546
Derivative contracts	4	419	448	(300)	571
Nuclear decommissioning trusts[3]	1,502	1,026			2,528
Long-term disability plan	7				7
Total assets[4]	5,056	1,445	451	(300)	6,652
Liabilities at Fair Value					
Derivative contracts	(2)	(397)	(753)	198	(954)
Net assets (liabilities)	**$ 5,054**	**$ 1,048**	**$ (302)**	**$ (102)**	**$ 5,698**

(1) Represents cash collateral and the impact of netting across the levels of the fair value hierarchy. Netting among positions classified within the same level is included in that level.

(2) Included in cash and cash equivalents and short-term investments on Edison International's consolidated balance sheet.

(3) Excludes net liabilities of $1 million and $4 million at March 31, 2009 and December 31, 2008, respectively, of interest and dividend receivables and receivables related to pending securities sales and payables related to pending securities purchases.

(4) Excludes $32 million at both March 31, 2009 and December 31, 2008, 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 derivative contracts:

In millions	Three Months Ended March 31, 2009	2008
	(Unaudited)	
Fair value of derivative contracts, net at January 1,	**$ (305)**	$ 98
Total realized/unrealized gains (losses):		
Included in earnings[(1)]	**146**	33
Included in regulatory assets and liabilities[(2)]	**388**	53
Included in accumulated other comprehensive income		(2)
Purchases and settlements, net	**(85)**	12
Transfers in or out of Level 3	**(3)**	(3)
Fair value of derivative contracts, net at March 31	**$ 141**	$ 191
Change during the period in unrealized gains related to net derivative contracts, held at March 31[(3)]	**$ 464**	$ 65

(1) $146 million and $33 million reported in "Competitive power generation" revenue on Edison International's consolidated statement of income for the three months ended March 31, 2009 and 2008, respectively.

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

(3) $73 million and $(4) million reported in "Competitive power generation" revenue on Edison International's consolidated statements of income for the three months ended March 31, 2009 and 2008, respectively. The remainder of the unrealized gains relates to SCE. See (2) above.

Level 3 derivative contracts reflect EME's load requirements services contracts. The energy price risk related to these contracts was substantially hedged, but such hedge contracts are classified as Level 2 and, therefore, not reflected as an offsetting position in Level 3.

Nuclear Decommissioning Trusts

SCE is collecting in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. Funds collected, together with accumulated earnings, will be utilized solely for decommissioning. The CPUC has set certain restrictions related to the investments of these trusts.

Trust investments (at fair value) include:

In millions	Maturity Dates	March 31, 2009	December 31, 2008
		(Unaudited)	
Municipal bonds	2009 2044	**$ 614**	$ 629
Stocks		**1,181**	1,308
United States government issues	2009 2049	**300**	304
Corporate bonds	2009 2047	**279**	260
Short-term investments, primarily cash equivalents	2009	**25**	23
Total		**$ 2,399**	$ 2,524

Note: Maturity dates as of March 31, 2009.

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The following table sets forth a summary of changes in the fair value of the trust for the three months ended March 31, 2009:

In millions	**2009**
	(Unaudited)
Balance at beginning of period	**$ 2,524**
Realized gains net	**12**
Unrealized losses net	**(73)**
Other-than-temporary impairments	**(94)**
Earnings and other	**30**
Balance at March 31, 2009	**$ 2,399**

The decrease in the trust investments was primarily due to net realized losses, net unrealized losses and other-than-temporary impairments resulting from a volatile stock market environment. Due to regulatory mechanisms, earnings, unrealized and realized gains and losses (including other-than-temporary impairments) have no impact on operating revenue.

Nuclear decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately $46 million per year. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. These contributions are determined based on an analysis of the current value of trusts assets and long-term forecasts of cost escalation, the estimate and timing of decommissioning costs, and after-tax return on trust investments. Favorable or unfavorable investment performance in a period will not change the amount of contributions for that period. However, trust performance for the three years leading up to a CPUC review proceeding will provide input into future contributions. On April 3, 2009, SCE submitted its triennial nuclear decommissioning application, requesting that its trust fund contributions increase to approximately $64.5 million per year, beginning on January 1, 2011. The CPUC has set certain restrictions related to the investments of these trusts. If additional funds are needed for decommissioning, it is probable that the additional funds will be recoverable through customer rates.

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Note 11. Regulatory Assets and Liabilities

Regulatory assets included on the consolidated balance sheets are:

In millions	March 31, 2009	December 31, 2008
	(Unaudited)	
Current:		
Regulatory balancing accounts	**$ 402**	$ 455
Energy derivatives	**168**	138
Deferred FTR proceeds		9
Other	**1**	3
	$ 571	$ 605
Long-term:		
Regulatory balancing accounts	**$ 31**	$ 29
Flow-through taxes net	**1,402**	1,337
ARO	**396**	224
Unamortized nuclear investment net	**363**	375
Nuclear-related ARO investment net	**273**	278
Unamortized coal plant investment net	**76**	79
Unamortized loss on reacquired debt	**304**	309
SFAS No. 158 pensions and postretirement benefits	**1,890**	1,882
Energy derivatives	**358**	723
Environmental remediation	**40**	40
Other	**140**	138
	$ 5,273	$ 5,414
Total Regulatory Assets	**$ 5,844**	$ 6,019

Regulatory liabilities included on the consolidated balance sheets are:

In millions	March 31 2009	December 31, 2008
	(Unaudited)	
Current:		
Regulatory balancing accounts	**$ 962**	$ 1,068
Rate reduction notes transition cost overcollection		20
Energy derivatives	**5**	6
Deferred FTR costs	**4**	13
Other	**1**	4
	$ 972	$ 1,111
Long-term:		
Regulatory balancing accounts	**$ 38**	$ 43
Costs of removal	**2,434**	2,368
Employee benefit plans	**70**	70

	$	**2,542**	$	2,481
Total Regulatory Liabilities	**$**	**3,514**	$	3,592

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Note 12. Business Segments

Edison International's reportable business segments include its electric utility operation segment (SCE), a competitive power generation segment (EME), and a financial services and other segment (Edison Capital and other EMG subsidiaries). Edison International evaluates performance based on net income.

SCE is a rate-regulated electric utility that supplies electric energy to a 50,000 square-mile area of central, coastal and Southern California. SCE also produces electricity. EME is engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from electric power generation facilities. EME also conducts hedging and energy trading activities in power markets open to competition. Edison Capital is a provider of financial services with investments worldwide.

Segment information was:

	Three Months Ended March 31,	
In millions	**2009**	**2008**
	(Unaudited)	
Operating Revenue (Loss):		
Electric utility	**$ 2,189**	$ 2,379
Competitive power generation	**612**	719
Financial services and other[1]	**12**	14
Parent and other[3]	**(1)**	1
Consolidated Edison International	**$ 2,812**	$ 3,113
Net Income (Loss) attributable to Edison International:		
Electric utility	**$ 208**	$ 150
Competitive power generation[2]	**56**	145
Financial services and other[1]	**(8)**	9
Parent and other[3]	**(6)**	(5)
Consolidated Edison International	**$ 250**	$ 299

(1) Includes amounts from other EMG subsidiaries that are not significant as a reportable segment.

(2) Includes earnings (loss) from discontinued operations of $3 million and $(5) million for the three months ended March 31, 2009 and 2008, respectively.

(3) Includes amounts from Edison International (parent), and other Edison International subsidiaries that are not significant as a reportable segment, as well as intercompany eliminations.

Note 13. Investments in Leveraged Leases, Partnerships and Unconsolidated Subsidiaries

Leveraged Leases

Edison Capital is the lessor in various power generation, electric transmission and distribution, transportation and telecommunication leases with terms of 24 to 38 years. Each of Edison Capital's leveraged lease transactions was completed and accounted for in accordance with SFAS No. 13, "Accounting for Leases." All operating, maintenance, insurance and decommissioning costs are the responsibility of the lessees. The acquisition costs of these facilities were $5.8 billion and $6.2 billion at March 31, 2009 and December 31, 2008, respectively. The equity investment in these facilities is generally 20% of the cost to acquire the facilities. The balance of the acquisition costs was funded by nonrecourse debt secured by first liens on the leased property. The lenders do not have recourse to Edison Capital in the event of loan default.

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The net investment in leveraged leases is:

In millions	March 31, 2009	December 31, 2008
	(Unaudited)	
Rental receivables net	**$ 3,051**	$ 3,227
Estimated residual value	**21**	42
Unearned income	**(733)**	(802)
Investments in leveraged leases	**2,339**	2,467
Deferred income taxes	**(2,192)**	(2,313)
Net investments in leveraged leases	**$ 147**	$ 154

Pursuant to the Global Settlement, Edison Capital terminated its interests in the cross-border leases (see "Global Settlement" in Note 4 for further discussion).

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

INTRODUCTION

This MD&A for the three months ended March 31, 2009 discusses material changes in the consolidated financial condition, results of operations and other developments of Edison International since December 31, 2008, and as compared to the three months ended March 31, 2008. This discussion presumes that the reader has read or has access to Edison International's MD&A for the calendar year 2008 (the year-ended 2008 MD&A), which was included in Edison International's 2008 annual report to shareholders and incorporated by reference into Edison International's Annual Report on Form 10-K for the year ended December 31, 2008, filed with the Securities and Exchange Commission.

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

- the cost of capital and the ability to borrow funds and access to capital markets on reasonable terms, particularly in light of current credit conditions in the capital markets;
- the effect of current economic conditions on the availability and creditworthiness of counterparties and the resulting effects on liquidity in the power and fuel markets and/or the ability of counterparties to pay amounts owed in excess of collateral provided in support of their obligations;
- the ability to procure sufficient resources to meet expected customer needs in the event of significant counterparty defaults under power-purchase agreements;
- changes in the fair value of investments and other assets;
- the ability of Edison International to meet its financial obligations and to pay dividends on its common stock;
- the ability of SCE to recover its costs in a timely manner from its customers through regulated rates;
- decisions and other actions by the CPUC, the FERC and other regulatory authorities and delays in regulatory actions;
- market risks affecting SCE's energy procurement activities;
- changes in interest rates, rates of inflation including those rates which may be adjusted by public utility regulators, and foreign exchange rates;

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governmental, statutory, regulatory or administrative changes or initiatives affecting the electricity industry, including the market structure rules applicable to each market;

environmental laws and regulations, both at the state and federal levels, or changes in the application of those laws, that could require additional expenditures or otherwise affect the cost and manner of doing business;

risks associated with operating nuclear and other power generating facilities, including operating risks, nuclear fuel storage, equipment failure, availability, heat rate, output, availability and cost of spare parts, and cost of repairs and retrofits;

the cost and availability of labor, equipment and materials;

the ability to obtain sufficient insurance, including insurance relating to SCE's nuclear facilities and wildfire-related liability, and to recover the costs of such insurance;

effects of legal proceedings, changes in or interpretations of tax laws, rates or policies, and changes in accounting standards;

creditworthiness of suppliers and other project participants and their ability to deliver goods and services under their contractual obligations to EME and its subsidiaries or to pay damages if they fail to fulfill those obligations;

the outcome of disputes with the IRS and other tax authorities regarding tax positions taken by Edison International;

the continued participation of Edison International's subsidiaries in tax-allocation and payment agreements;

supply and demand for electric capacity and energy, and the resulting prices and dispatch volumes, in the wholesale markets to which EMG's generating units have access;

the cost and availability of coal, natural gas, fuel oil, nuclear fuel, and associated transportation to the extent not recovered through regulated rate cost escalation provisions or balancing accounts;

the cost and availability of emission credits or allowances for emission credits;

transmission congestion in and to each market area and the resulting differences in prices between delivery points;

the ability to provide sufficient collateral in support of hedging activities and purchased power and fuel;

the risk of counterparty default in hedging transactions or power-purchase and fuel contracts;

the extent of additional supplies of capacity, energy and ancillary services from current competitors or new market entrants, including the development of new generation facilities and technologies;

the difficulty of predicting wholesale prices, transmission congestion, energy demand and other aspects of the complex and volatile markets in which EMG and its subsidiaries participate;

- general political, economic and business conditions;
- weather conditions, natural disasters and other unforeseen events; and
- the risks inherent in the development of generation projects as well as transmission and distribution infrastructure replacement and expansion including those related to siting, financing, construction, permitting, and governmental approvals.

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

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

This MD&A is presented in 9 major sections. The company-by-company discussion of SCE, EMG, and Edison International (parent) includes discussions of liquidity, market risk exposures, and other matters (as relevant to each principal business segment). The remaining sections discuss Edison International on a consolidated basis. The consolidated sections should be read in conjunction with the discussion of each company's section.

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EDISON INTERNATIONAL: MANAGEMENT OVERVIEW

Introduction

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

Areas of Business Focus

Commodity Prices

Continuing economic recessionary conditions, among other things, were a contributing factor to a decline in electrical demand as well as a decline in natural gas and power prices during the first quarter of 2009. These factors have had an adverse impact on EMG's results of operations. Fluctuations in commodity prices do not impact SCE's results of operations due to ratepayer recovery of purchased power costs. As a result of lower prices, SCE projects that it will recover its under-collected purchased power costs recorded in the ERRA balancing account without an increase in rates. See "SCE: Regulatory Developments Current Regulatory Developments Energy Resource Recovery Account Proceedings" in the year-ended 2008 MD&A.

The electrical load, calculated from published data by PJM, for the Northern Illinois and PJM West Hub locations declined 6% and 2%, respectively, compared to the first quarter of 2008. The decline in natural gas prices together with lower electrical demand have resulted in significantly lower energy prices. Furthermore, spot energy prices affecting the Illinois Plants were adversely impacted by congestion affecting power exported from the Northern Illinois control area. The average 24-hour PJM market price for energy per MWh at the Northern Illinois Hub and the PJM West Hub declined to $34.06/MWh and $49.09/MWh, respectively, during the first quarter of 2009 as compared to $53.38/MWh and $68.52/MWh, respectively, during the first quarter of 2008. In the first quarter of 2009, the average realized energy prices per MWh were higher than the average 24-hour PJM market prices due to higher hedge prices. As reflected in the net income summary below, these factors had an adverse impact on the results of operations during the first quarter of 2009. Lower electrical load has also generally decreased congestion in the eastern power grid, thereby resulting in lower trading income in the first quarter of 2009.

Business Development and Capital Commitments

SCE

SCE's growth strategy includes improving reliability and expanding the capability of its distribution and transmission infrastructure, constructing and replacing generation assets, and deploying advanced metering infrastructure. SCE continues to implement its growth strategy and revised its 2009 2013 capital investment plan to be consistent with the revenue requirements authorized in its 2009 GRC final decision, as well as other CPUC and FERC proceedings. SCE's significant planned projects are as follows:

Transmission and Distribution Projects

Devers-Palo Verde II A transmission project that will install a high voltage (500 kV) transmission line from the Valley substation in Romoland, California via the Devers substation near Palm Springs, California to a new substation to be constructed near Palo Verde, west of Phoenix, Arizona. SCE

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continues its efforts to obtain the regulatory approvals necessary to construct the DPV2 project. The project is currently expected to be placed in service in 2013, subject to licensing and regulatory approvals. Over the period 2009 2013, SCE expects to spend $723 million for the California portion of the project. If SCE and the relevant regulatory agencies determine that construction of the Arizona portion is in the interest of California ratepayers, SCE will seek regulatory approvals for the Arizona portion, and would expect to spend $304 million.

Tehachapi Transmission Project An eleven segment project consisting of new and upgraded transmission lines and associated substations built primarily to enable the development of renewable energy generated primarily by wind farms in remote areas of eastern Kern County, California. Tehachapi segments one through three are under construction and are expected to be placed in service at various dates over the next two years. SCE continues to seek the necessary licensing permits for Tehachapi segments four through eleven, which are expected to be placed in service between 2011 and 2013, subject to receipt of licensing and regulatory approvals. SCE expects to spend $2.1 billion over the period 2009 2013.

Rancho Vista Substation Project A new 500 kV substation in the City of Rancho Cucamonga that is under construction and expected to be placed in service in 2009. SCE expects to spend $38 million in 2009.

Other non-project specific capital investments consist of $3.1 billion for transmission development and $9.7 billion for distribution projects to improve reliability and expand capability of its infrastructure over the period 2009 2013.

Generation Projects

San Onofre Steam Generator Replacement Project Recently, SCE took delivery of the first two of four steam generators. The project is intended to enable San Onofre to operate until the end of its initial license period in 2022, and beyond if license renewal proves feasible. SCE expects to spend $456 million over the period 2009 2011.

Solar Photovoltaic Program A program to develop up to 160 MW of utility-owned Solar PV generating facilities (generally ranging in size from 1 to 2 MW) each on commercial and industrial rooftop and other space in SCE's service territory. See "SCE: Liquidity Capital Expenditures Solar Photovoltaic Program" for further discussion.

Other Projects

EdisonSmartConnect™ SCE's advanced metering project that will install state-of-the-art "smart" meters in approximately 5.3 million households and small businesses throughout its service territory. SCE expects to begin deploying meters in 2009, and anticipates completion of the deployment in 2012. SCE estimates capital costs of $1.2 billion over the period 2009 2012 and has obtained CPUC authorization to recover $1.6 billion of capital and operating costs related to this deployment phase.

SCE's 2009 2013 revised total capital investment plan includes capital spending in the range of $16.7 billion to $20.2 billion. See "SCE: Liquidity Capital Expenditures" for further discussion.

EMG

At March 31, 2009, EME had 1,015 MW of wind projects in service and another 170 MW of wind projects under construction, with scheduled completion dates during 2009. EME's wind projects under construction are currently funded through equity. During the first quarter of 2009, EME completed construction and commenced operations of the 80 MW Elkhorn Ridge project located in Nebraska.

EME is continuing to preserve capital by focusing on a selective growth strategy, primarily on completion of projects under construction and development of sites for future renewable projects deploying current turbine commitments. EME has contracts for the purchase of 942 MW of new turbines with scheduled payment obligations of up to $667 million in 2009 and $240 million in 2010. Turbine payments scheduled during the first quarter of 2009 were deferred by agreement with certain suppliers. EME and Suzlon Wind Energy Corporation are discussing a number of contractual performance matters and related turbine payments. With respect to turbine payments scheduled for the balance of 2009, EME has continued to engage in discussions with each of the turbine suppliers to defer the payment of the remaining commitments under each of the turbine supply agreements. At March 31, 2009, EME had recorded wind turbine deposits of $336 million, included in other long-term assets on its consolidated balance sheet. Under certain of these agreements, EME may terminate the purchase of individual turbines, or groups of turbines, for convenience. If EME terminated one or more turbine supply agreements, it would result in a charge related to such termination.

EME plans to defer construction expenditures for new wind projects until financing becomes available, which may require power purchase agreements. EME has observed a trend toward delays in the award of power purchase agreements by potential offtakers. As a result, the time to complete development of new wind projects has increased, thereby delaying EME's expectation on timing of new projects. If EME is unable to obtain power purchase agreements, complete development of wind projects, and obtain project financing on acceptable terms and conditions, it may terminate a portion of the turbines on order. Such an event would likely result in a material charge. EME plans to store turbines that are delivered until needed for construction of new wind projects.

Federal and State Income Taxes

In April 2009, Edison International was advised by the IRS that the Staff of the Joint Committee on Taxation, a committee of the United States Congress (the "Joint Committee"), completed its review of the Global Settlement, and did not recommend any adjustments to the terms of the Global Settlement submitted for review. Pursuant to the Global Settlement, Edison Capital subsequently terminated its interests in its cross-border leases and Edison International and the IRS finalized the Global Settlement on May 5, 2009. See "Edison International Notes to Consolidated Financial Statements Note 4. Income Taxes" and "Other Developments Federal and State Income Taxes" for further information.

Environmental Developments

As discussed in the Edison International 2008 Annual Report on Form 10-K, Midwest Generation is subject to various commitments with respect to environmental compliance for the Illinois Plants. Midwest Generation is testing selective non-catalytic NO_X removal technologies and reagent based SO_2 removal technologies that may be employed to meet compliance requirements. These technologies would be deployed at the Illinois Plants in a manner which could optimize compliance during 2010 through 2015, subject to approval of construction permits by the Illinois EPA. A decision regarding whether or not to proceed with the alternative compliance program will occur following completion of testing and evaluation of results. Under the current conditions, Midwest Generation cannot predict what specific method will be used or the costs that will be incurred to comply with the Combined Pollutant Standard.

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Earnings Performance

The table below presents Edison International's earnings for the three months ended March 31, 2009 and 2008, and the relative contributions by its subsidiaries.

In millions	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Earnings (Loss) from Continuing Operations:		
SCE	**$ 208**	$ 150
EMG	**45**	159
Edison International (parent) and other	**(6)**	(5)
Edison International Earnings from Continuing Operations	**247**	304
Edison International Earnings (Loss) from Discontinued Operations	**3**	(5)
Edison International Net Income	**$ 250**	$ 299

Earnings (Loss) from Continuing Operations

SCE's earnings from continuing operations were $208 million in the first quarter of 2009, compared with earnings of $150 million in the first quarter of 2008. The increase in 2009 was primarily due to SCE's 2009 GRC decision in March, which was effective January 1, 2009, and expense timing differences arising from the delay in receiving the GRC decision.

EMG's earnings from continuing operations were $45 million in the first quarter of 2009, compared with earnings of $159 million in the first quarter of 2008. The decrease in 2009 was primarily due to significant decline in Midwest Generation and Homer City results from lower power prices and generation levels as well as reduced trading income and a loss from the termination of two lease agreements at Edison Capital in 2009. These decreases were partially offset by higher earnings from the wind projects in operation. Results for the first quarter of 2008 also included the favorable buy-out of a coal contract at Midwest Generation.

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SOUTHERN CALIFORNIA EDISON COMPANY

SCE: REGULATORY MATTERS

Current Regulatory Developments

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

2009 General Rate Case Proceeding

On March 12, 2009, the CPUC issued a final decision in SCE's 2009 GRC, authorizing a $4.83 billion base revenue requirement for 2009. The CPUC also authorized a methodology for calculating post-test year revenue requirements that would result in an approximate base revenue requirement of $5.04 billion in 2010 and $5.25 billion in 2011. In addition, the 2009 GRC decision establishes new balancing account regulatory treatment for SCE's medical, dental, and vision expenses, and its share of Palo Verde operation and maintenance expenses, and modifies SCE's existing pension and PBOP balancing accounts to allow annual recovery or refund of the recorded year-end balances. During the first quarter of 2009, SCE implemented the updated revenue requirement retroactive to January 1, 2009 consistent with the CPUC authorization. In addition, SCE has slightly revised its capital expenditure forecasts for the period 2009 2013. See "SCE: Liquidity Capital Expenditures" for further discussion.

Peaker Plant Generation Projects

As discussed under the heading "Peaker Plant Generation Projects," in the year-ended 2008 MD&A, SCE pursued development of five combustion turbine peaker plants, four of which were placed online in August 2007 to help meet peak customer demands and other system requirements. In April 2009, the California Coastal Commission approved the coastal development permit for the fifth peaker, reversing the City of Oxnard's denial. SCE is moving forward with the construction of the fifth peaker plant at the original site.

SCE: OTHER DEVELOPMENTS

Navajo Nation Litigation

As discussed under the heading, "SCE: Other Developments Navajo Nation Litigation" in the year-ended 2008 MD&A, the Navajo Nation filed a complaint in June 1999 against SCE, among other defendants, and filed a related case against the U.S. Government in December 1993 arising out of the coal supply agreement for Mohave. In April 2009, in a related case against the U.S. Government, the U.S. Supreme Court found that the Navajo Nation did not have a claim for compensation. SCE cannot predict the outcome of the Tribes' complaints against SCE or the ultimate impact of the April 2009 U.S. Supreme Court decision on these complaints.

Federal and State Income Taxes

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

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SCE: LIQUIDITY

Overview

As of March 31, 2009, SCE had $2.4 billion of available liquidity made up of $1.18 billion of cash and equivalents and short-term investments ($83 million of which was held by SCE's consolidated VIEs), as well as $1.22 billion remaining under credit facilities. The following table summarizes the status of SCE's credit facilities at March 31, 2009:

In millions		**Credit Facilities**[1]
Commitment	$	3,000
Less: Unfunded commitment from Lehman Brothers subsidiary		(81)
		2,919
Outstanding borrowings		(1,558)
Outstanding letters of credit		(137)
Amount available	**$**	**1,224**

(1) SCE has two credit facilities with various banks. In March 2008, SCE amended its existing $2.5 billion five-year credit facility, extending the maturity to February 2013. The amendment also provides four extension options which, if all exercised, and agreed to by lenders, will result in a final termination in February 2017. In March 2009, SCE entered into a new $500 million 364-day revolving credit facility terminating on March 16, 2010. SCE expects to use the additional liquidity provided by the facility to address potential requirements of SCE's ongoing procurement-related needs.

During the first quarter of 2009, SCE made net repayments of $335 million on amounts borrowed under its $2.5 billion credit facility.

As of March 31, 2009, SCE's long-term debt, including current maturities of long-term debt, was $6.74 billion. In March 2009, SCE issued $500 million of 6.05% first and refunding mortgage bonds due in 2039 and $250 million of 4.15% first and refunding mortgage bonds due in 2014. The bond proceeds are to be used for general corporate purposes.

SCE's estimated cash outflows during the 12-month period following March 31, 2009 are expected to consist of:

- Projected capital expenditures primarily to replace and expand distribution and transmission infrastructure and construct and replace major components of generation assets (see " Capital Expenditures" below);
- Fuel and procurement-related costs (see "SCE: Regulatory Matters Current Regulatory Developments Energy Resource Recovery Account Proceedings" in the year-ended 2008 MD&A), including collateral requirements (see " Margin and Collateral Deposits");
- In December 2008 the Board of Directors of SCE declared a $100 million dividend to Edison International which was paid in January 2009. Additional dividends by SCE are dependent upon several factors including the actual level of capital expenditures, operating cash flows and earnings;
- Maturity and interest payments on short- and long-term debt outstanding;
- General operating expenses; and

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Pension and PBOP trust contributions.

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

On February 17, 2009, President Obama signed the American Recovery and Reinvestment Act of 2009 which extended the accelerated bonus depreciation provision through the end of 2009. Edison International expects that certain capital expenditures incurred by SCE during 2009 will qualify for this accelerated bonus depreciation, which would provide additional cash flow benefits that would be realized in 2009 estimated to be in the range of approximately $125 million to $175 million for tax year 2009.

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

Capital Expenditures

SCE's capital investment plan projects total capital expenditures for the period 2009 2013 to be in the range of $16.7 billion to $20.2 billion. The 2009 2011 planned capital expenditures for CPUC-jurisdictional projects are consistent with the revenue requirements authorized in SCE's 2009 GRC. Recovery of planned capital expenditures for CPUC-jursidictional projects beyond 2011 is subject to the outcome of future CPUC general rate cases or other CPUC approvals. Recovery of certain projects included in the 2009 2013 capital investment plan have been approved or will be requested through other CPUC-authorized mechanisms on a project-by-project basis. These projects include, among others, SCE's Solar Photovoltaic Program (based on the scope of the proposed decision as discussed below) and SCE's EdisonSmartConnect project. Recovery of the 2009 planned capital expenditures for FERC-jurisdictional projects is subject to FERC approval in SCE's pending 2009 Rate Case (see "SCE: Current Regulatory Developments FERC Rate Case" in the year-ended 2008 MD&A). Recovery of planned capital expenditures for FERC-jurisdictional projects beyond 2009 is subject to future FERC approval.

The level of growth is dependent on access to capital markets, regulatory decisions, and economic conditions in the U.S. The completion of the projects, the timing of expenditures, and the associated cost recovery may be affected by permitting requirements and delays, construction delays, availability of labor, equipment and materials, financing, legal and regulatory approvals and developments, weather and other unforeseen conditions.

SCE's first quarter 2009 capital expenditures (including accruals) were $514 million related to its 2009 capital plan. SCE's first quarter 2009 capital expenditures were less than forecast, primarily due to timing delays including the delay in the 2009 GRC decision. The estimated capital expenditures for the next five years may vary from SCE's current forecast. If SCE assumes the same level of variability to forecast experienced in 2008 (approximately 18%) the estimated capital expenditures for the next five years would vary in the range of: 2009 $2.8 billion to $3.4 billion; 2010 $3.2 billion to $3.9 billion; 2011 $3.5 billion to $4.2 billion; 2012 $3.7 billion to $4.4 billion; and 2013 $3.6 billion to $4.3 billion.

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Solar Photovoltaic Program

In March 2009, the CPUC issued a proposed decision that would reduce the size of the utility-owned solar photovoltaic program from 250 MW to 160 MW and would reduce the incentive adder from 100 basis points to 50 basis points. The proposed decision also included mechanisms in which costs savings or overages would be split between ratepayers and shareholders and would include potential penalties under a performance guarantee. Due to the reduction in the size of the program and the cost thresholds proposed in the decision, SCE could be subject to potential penalties or may not be able to continue with the program. A final decision is expected in the second quarter of 2009. SCE cannot predict the final outcome of this proceeding.

Credit Ratings

At March 31, 2009, SCE's credit ratings were as follows:

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

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

Dividend Restrictions and Debt Covenants

The CPUC regulates SCE's capital structure and limits the dividends it may pay Edison International. In SCE's most recent cost of capital proceeding, the CPUC 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 March 31, 2009, SCE's 13-month weighted-average common equity component of total capitalization was 50.5% resulting in the capacity to pay $344 million in additional dividends.

SCE has a debt covenant in its credit facility that requires a debt to total capitalization ratio of less than or equal to 0.65 to 1 to be met. At March 31, 2009, SCE's debt to total capitalization ratio was 0.52 to 1.

Margin and Collateral Deposits

Certain derivative instruments and power procurement contracts under SCE's power and natural gas trading activities contain margin and collateral requirements. SCE has historically provided collateral in the form of cash and letters of credit for the benefit of counterparties related to the net of accounts payable, accounts receivable, unrealized losses and unrealized gains in connection with derivative activities. 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. Future margin and collateral requirements may be higher (or lower) than requirements at March 31, 2009, due to the addition of incremental power and energy procurement contracts with margining and collateral requirements, if any, and the impact of changes in wholesale power and natural gas prices on SCE's contractual obligations.

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Certain of these margin and collateral requirements 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 liability or post additional collateral. The table below illustrates the amount of collateral posted by SCE to its counterparties as well as the additional collateral that would be required if the credit-risk-related contingent features underlying these agreements were triggered on March 31, 2009.

In millions	
Collateral posted as of March 31, 2009[1]	$ 284
Incremental collateral requirements resulting from a potential downgrade of SCE's credit rating to below investment grade	148
Total posted and potential collateral requirements[2]	**$ 432**

(1) Collateral posted consisted of $110 million which was offset against derivative liabilities in accordance with the implementation of FIN 39-1, and $174 million provided to counterparties and other brokers (consisting of $37 million in cash reflected in "Margin and collateral deposits" on the consolidated balance sheets and $137 million in letters of credit).

(2) Total posted and potential collateral requirements may increase by an additional $20 million, based on SCE's forward position as of March 31, 2009, due to adverse market price movements over the remaining life of the existing contracts using a 95% confidence level.

In the table above $6 million of collateral posted as of March 31, 2009 related to derivative liabilities, and $2 million of incremental collateral requirements related to derivative liabilities.

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

SCE: MARKET RISK EXPOSURES

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

Commodity Price Risk

Introduction

As discussed in the year-ended 2008 MD&A, SCE is exposed to commodity price risk from its purchases of capacity and ancillary services to meet peak energy requirements and from exposure to natural gas prices that affect costs associated with power purchased from QFs, fuel tolling arrangements, and its own gas-fired generation, including SCE's Mountainview and peaker plants.

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Natural Gas and Electricity Price Risk

As discussed in the year-ended 2008 MD&A, SCE has an active hedging program in place to minimize ratepayer exposure to variability in market prices; however, to the extent that SCE does not mitigate the exposure to commodity price risk, the unhedged portion is subject to the risks and benefits of spot-market price movements, which are ultimately passed-through to ratepayers.

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

	March 31, 2009		December 31, 2008	
In millions	**Assets**	**Liabilities**	**Assets**	**Liabilities**
Electricity options, swaps and forward arrangements	**$ 8**	**$ 26**	$ 7	$ 15
Natural gas options, swaps and forward arrangements	**41**	**373**	80	304
Firm transmission rights and congestion revenue rights[(1)]	**474**		81	
Tolling arrangements[(2)]	**46**	**595**	63	647
Netting and collateral	**(1)**	**(111)**		(72)
Total	**$ 568**	**$ 883**	$ 231	$ 894

(1) During the first quarter of 2008, the CAISO held an auction for FTRs. SCE participated in the CAISO auction and paid $62 million to secure FTRs for the period April 2008 through March 2009. As of March 31, 2009, there were no FTRs outstanding. The FTRs have been replaced with CRRs in the CAISO's market redesign environment. See " Market Redesign and Technology Upgrade" below for further discussion. SCE recognized the FTRs at fair value.

In September 2007 and November 2008, the CAISO allocated CRRs for the period April 2009 through December 2017 based on SCE's load requirements. In addition, SCE participated in CAISO auctions for the procurement of additional CRRs. The CRRs meet the definition of a derivative under SFAS No. 133.

(2) In compliance with a CPUC mandate, SCE held an open, competitive solicitation that produced agreements with different project developers who have agreed to construct new Southern California generating resources. SCE has entered into a number of contracts, of which five received regulatory approval in the fourth quarter of 2008 and are recorded as derivative instruments. The contracts provide for fixed capacity payments as well as pricing for energy delivered based on a heat rate and contractual operation and maintenance prices. However, due to uncertainty regarding the availability of required emission credits, some of the generating resources may not be constructed and the contracts associated with these resources could therefore terminate, at which time SCE would no longer account for these contracts as derivatives. See "Other Developments Environmental Matters Priority Reserve Legal Challenges" in the year-ended 2008 MD&A.

SCE recognizes realized gains and losses on dervitative instruments as purchased power expense and recovers these costs from ratepayers. Due to expected future recovery from ratepayers, unrealized gains and losses are deferred and are not recognized as purchased power expense until realized. As a result, realized and unrealized gains and losses do not affect earnings, but may temporarily affect cash flows. Realized losses on economic hedging activities were $98 million and $2 million for the first quarter of 2009 and 2008, respectively. Unrealized gains on economic hedging activities were $333 million and $155 million for the first quarter of 2009 and 2008, respectively. Changes in realized and unrealized gains and losses on economic hedging activities were primarily due to significant decreases in forward natural gas prices in 2009 compared to 2008.

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

Market Redesign and Technology Upgrade

The MRTU market became effective on March 31, 2009 and SCE began participating in the day-ahead and real-time markets for the sale of its generation and purchases of its load requirements. See "SCE: Market Risk Exposures Commodity Price Risk Market Redesign and Technology Upgrade" in the year-ended 2008 MD&A for a further description of these markets.

Interest Rate Risk

SCE is exposed to changes in interest rates primarily as a result of its borrowing and investing activities used for liquidity purposes, to fund business operations and to finance capital expenditures. The nature and amount of SCE's long-term and short-term debt can be expected to vary as a result of future business requirements, market conditions and other factors. At March 31, 2009, SCE did not believe that its short-term debt was subject to interest rate risk, due to the fair market value being approximately equal to the carrying value. At March 31, 2009, the fair market value of SCE's long-term debt (including long-term debt due within one year) was $6.85 billion, compared to a carrying value of $6.74 billion.

Credit Risk

As discussed in the year-ended 2008 MD&A, 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.

The credit risk exposure from counterparties for power and gas trading activities is measured as the sum of net accounts receivable (accounts receivable less accounts payable) and the current fair value of net derivative assets (derivative assets less derivative liabilities) reflected on the balance sheet. SCE enters into master agreements which typically provide for a right of setoff. Accordingly, SCE's credit risk exposure from counterparties is based on a net exposure under these arrangements.

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At March 31, 2009, the amount of balance sheet exposure as described above, broken down by the credit ratings of SCE's counterparties, was as follows:

	March 31, 2009		
In millions	**Exposure[2]**	**Collateral**	**Net Exposure**
S&P Credit Rating[1]			
A or higher	$ 66	$ (4)	$ 62
A-	476		476
BBB+			
BBB			
BBB-			
Below investment grade and not rated			
Total	**$ 542**	**$ (4)**	**$ 538**

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

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

The credit risk exposure set forth in the above table is comprised of $13 million of net accounts receivable and payables and $529 million representing the fair value, adjusted for counterparty credit reserves, of derivative contracts.

Due to recent developments in the financial markets, the credit ratings may not be reflective of the related credit risk. The CAISO comprises 88% of the total net exposure above and is mainly related to purchases of CRRs (see " Commodity Price Risk" for further information).

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EDISON MISSION GROUP

EMG: LIQUIDITY

Liquidity

At March 31, 2009, EMG and its subsidiaries had cash and cash equivalents and short-term investments of $2.29 billion. EMG's subsidiaries had a total of $110 million of available borrowing capacity under their credit facilities. EME had a total of $88 million of available borrowing capacity under its $600 million corporate credit facility, and Midwest Generation had a total of $22 million of available borrowing capacity under its $500 million working capital facility. EMG's consolidated debt at March 31, 2009 was $4.73 billion, of which $24 million was current. In addition, EME's subsidiaries had $3.5 billion of long-term lease obligations related to their sale-leaseback transactions that are due over periods ranging up to 26 years.

The following table summarizes the status of the EME and Midwest Generation credit facilities at March 31, 2009:

In millions	**EME**	**Midwest Generation**
Commitment	$ 600	$ 500
Less: Commitment from Lehman Brothers subsidiary	(36)	
	564	500
Outstanding borrowings	(351)	(475)
Outstanding letters of credit	(125)	(3)
Amount available	**$ 88**	**$ 22**

On September 15, 2008, Lehman Brothers Holdings filed for protection under Chapter 11 of the U.S. Bankruptcy Code. A subsidiary of Lehman Brothers Holdings, Lehman Commercial Paper Inc., a lender in EME's credit agreement representing a commitment of $36 million, in September 2008 declined requests for funding under that agreement and in October 2008, filed for bankruptcy protection.

Access to the capital markets remains uncertain due to the financial market and economic conditions discussed in "Edison International: Management Overview" in the year-ended 2008 MD&A. Accordingly, EME's liquidity is currently comprised of cash on hand and cash flow generated from operations. Pending recovery of the capital markets, EME intends to preserve capital by focusing on a selective growth strategy, primarily on completion of projects under construction and development of sites for future renewable projects deploying current turbine commitments, and using its cash on hand and future cash flow to meet its existing contractual commitments. Long-term disruption in the capital markets could adversely affect EME's business plans and financial position.

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Capital Expenditures

At March 31, 2009, the estimated capital expenditures through 2011 by EME's subsidiaries for existing projects, corporate activities and turbine commitments were as follows:

In millions	April through December 2009	2010	2011
Illinois Plants			
Plant capital expenditures	$ 38	$ 96	$ 61
Environmental expenditures	11	(a)	(a)
Homer City Facilities			
Plant capital expenditures	25	55	29
Environmental expenditures	2	15	32
New Projects			
Projects under construction	33		
Turbine commitments	667	240	
Other capital expenditures	27	9	7
Total	**$ 803**	**$ 415**	**$ 129**

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

Expenditures for Existing Projects

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

Midwest Generation is subject to various commitments with respect to environmental compliance. Midwest Generation continues to review all technology and unit shutdown combinations, including interim and alternative compliance solutions. For more information on the current status of environmental improvements in Illinois, see "Edison International: Management Overview Areas of Business Focus Environmental Developments." For further discussion of environmental regulations, refer to "Edison International: Management Overview Areas of Business Focus Environmental Developments," and "Other Developments Environmental Matters" in the year ended 2008 MD&A.

Expenditures for New Projects

At March 31, 2009, EME had committed to purchase turbines (as reflected in the above table of capital expenditures) for wind projects that aggregate 942 MW. The turbine commitments generally represent approximately two-thirds of the total capital costs of EME's wind projects. As of March 31, 2009, EME had a development pipeline of potential wind projects with projected installed capacity of approximately 5,000 MW. The development pipeline represents potential projects with respect to which EME either owns the project rights or has exclusive acquisition rights. Completion of development of a wind project may take a number of years due to factors that include local permit requirements, willingness of local utilities to purchase renewable power at sufficient prices to earn an appropriate rate of return, and availability and prices of equipment. Furthermore, successful completion of a wind project is dependent upon obtaining permits and agreements necessary to support an investment. There is no assurance that each project included in the development pipeline currently or added in the future will be successfully completed, or that EME will be able to successfully develop projects utilizing all of its turbine commitments. For further discussion, see "Edison International: Management Overview Areas of Business Focus Business Development and Capital Commitments EMG."

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Big Sky Wind Project

The Big Sky wind project is a 240 MW planned wind project in Illinois. EME has commenced pre-construction activities for equipment purchases, site development and interconnection activities (approximately $100 million capitalized at March 31, 2009). Release of the project for full construction is pending a decision on selection of turbines and EME's access to project financing or capital markets. The costs to complete the Big Sky wind project, including construction and turbine transportation and installation, are expected to be approximately $165 million. This estimate excludes the turbine costs set forth as turbine commitments in the table above and costs incurred to date. Upon completion, the project plans to sell electricity into the PJM market as a merchant generator or to third-party offtakers under power sales contracts.

Walnut Creek Project

Walnut Creek Energy, a subsidiary of EME, was awarded by SCE, through a competitive bidding process, a ten-year power sales contract starting in 2013 for the output of the Walnut Creek project.

In July 2008, the Los Angeles Superior Court found that actions taken by the SCAQMD, in promulgating rules that had made available a "Priority Reserve" of emissions credits for new power generation projects, did not satisfy California environmental laws. In November 2008, the Los Angeles Superior Court enjoined the SCAQMD from issuing Priority Reserve emission credits to any facility, including new power projects, until a satisfactory environmental analysis is completed.

Legal challenges related to the Priority Reserve emission credits are continuing. In the air basins regulated by SCAQMD, the need for particulate matter (PM10) and SO_2 emission credits exceeds available supply, and it is difficult to create new credits. Walnut Creek will be unable to begin construction until the legal challenges to the Priority Reserve emission credits have been favorably resolved or another source of credits for the project has been identified. The capital costs to construct this project, excluding interest, are estimated in the range of $500 million to $600 million.

Credit Ratings

Overview

Credit ratings for EMG's direct and indirect subsidiaries at March 31, 2009, were as follows:

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

(1) First priority senior secured rating.

On December 23, 2008, S&P assigned a negative outlook to its corporate ratings for EME, Midwest Generation, and EMMT. On March 24, 2009, Moody's placed its corporate and debt ratings for EME and Midwest Generation under review for possible downgrade. S&P assigned a negative outlook to Edison Funding's credit rating and in August 2008, Moody's placed Edison Funding's senior notes under review for a possible rating downgrade. EMG cannot provide assurance that its current credit ratings or the credit ratings of its subsidiaries will remain in effect for any given period of time or that one or more of these ratings will not be lowered. EMG notes that these credit ratings are not recommendations to buy, sell or hold its securities and may be revised at any time by a rating agency.

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

Credit Rating of EMMT

The Homer City sale-leaseback documents restrict EME Homer City's ability to enter into trading activities, as defined in the documents, with EMMT to sell forward the output of the Homer City facilities if EMMT does not have an investment grade credit rating from S&P or Moody's or, in the absence of those ratings, if it is not rated as investment grade pursuant to EME's internal credit scoring procedures. These documents include a requirement that the counterparty to such transactions, and EME Homer City, if acting as seller to an unaffiliated third party, be investment grade. EME currently sells all the output from the Homer City facilities through EMMT, which has a below investment grade credit rating, and EME Homer City is not rated. In order to continue to sell forward the output of the Homer City facilities through EMMT, either: (1) a consent from the sale-leaseback owner participant must be obtained; or (2) EMMT must provide assurances of performance consistent with the requirements of the sale-leaseback documents. EME has obtained a consent from the sale-leaseback owner participants that allows EME Homer City to enter into such sales, under specified conditions, through March 1, 2014. EME is permitted to sell the output of the Homer City facilities into the spot market at any time. For further discussion, see "EMG: Market Risk Exposures Commodity Price Risk Energy Price Risk Affecting Sales from the Homer City Facilities."

Margin, Collateral Deposits and Other Credit Support for Energy Contracts

To reduce its exposure to market risk, EME hedges a portion of its electricity sales through EMMT, an EME subsidiary engaged in the power marketing and trading business. In connection with entering into contracts, EMMT may be required to support its risk of nonperformance through parent guarantees, margining or other credit support. EME has entered into guarantees in support of EMMT's hedging and trading activities; however, because the credit ratings of EMMT and EME are below investment grade, EME has historically also provided collateral in the form of cash and letters of credit for the benefit of counterparties related to the net of accounts payable, accounts receivable, unrealized losses, and unrealized gains in connection with these hedging and trading activities. At March 31, 2009, EMMT had deposited $47 million in cash with clearing brokers in support of futures contracts and had deposited $62 million in cash with counterparties in support of forward energy and congestion contracts. In addition, EME had received cash collateral of $373 million at March 31, 2009, to support credit risk of counterparties under margin agreements.

Future cash collateral requirements may be higher than the margin and collateral requirements at March 31, 2009, if wholesale energy prices or the amount hedged changes. EME estimates that margin and collateral requirements for energy and congestion contracts outstanding as of March 31, 2009 could increase by approximately $88 million over the remaining life of the contracts using a 95% confidence level. Certain EMMT hedge contracts do not require margining, but contain provisions that require EME or Midwest Generation to comply with the terms and conditions of their credit facilities. The credit facilities contain financial covenants which are described further in " Dividend Restrictions in Major Financings." Furthermore, the hedge contracts include provisions relating to a change in control or material adverse effect resulting from amendments or modifications to the related credit facility. Failure by EME or Midwest Generation to comply with these provisions would result in a termination event under the hedge contracts, enabling the counterparties to terminate and liquidate all outstanding transactions and demand immediate payment of amounts owed to them. EMMT also has hedge contracts that do not require margining, but contain the right of each party to request additional credit support in the form of adequate assurance of performance in the case of an adverse development affecting the other party. The aggregate fair value of all derivative instruments with credit-risk-related contingent features is in an asset position on March 31, 2009 and, accordingly, the contingent features

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described above do not currently have a liquidity exposure. Contingent features contained in EME's derivative agreements could potentially require $31 million of additional collateral to be provided to counterparties as of March 31, 2009 in the event that EME or Midwest Generation would fail to comply with the credit-related provisions in the agreements. Future increases in power prices could expose EME or Midwest Generation to termination payments or additional collateral postings under the contingent features described above.

Midwest Generation has cash on hand to support margin requirements specifically related to contracts entered into by EMMT related to the Illinois Plants. At March 31, 2009, Midwest Generation had available $22 million of borrowing capacity under its $500 million working capital facility. In addition, EME has cash on hand and $88 million of borrowing capacity available under its $600 million working capital facility to provide credit support to subsidiaries.

EME's Credit Facility Financial Ratios

EME's credit facility contains financial covenants which require EME to maintain a minimum interest coverage ratio and a maximum corporate-debt-to-corporate-capital ratio as such terms are defined in the credit facility. The following details of EME's interest coverage ratio and a maximum corporate-debt-to-corporate-capital ratio are provided as an aid to understanding the components of the computations as defined in the credit facility. This information is not intended to measure the financial performance of EME and, accordingly, should not be used in lieu of the financial information set forth in EME's consolidated financial statements.

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The following table sets forth the major components of the interest coverage ratio for the twelve months ended March 31, 2009 and December 31, 2008:

	Twelve Months Ended	
In millions	**March 31, 2009**	**December 31, 2008**
Funds Flow Available for Interest		
Distributions:		
Midwest Generation	**$ 171**	$ 206
EME Homer City	**80**	110
Big 4 Projects[1]	**113**	114
Other projects	**57**	55
Tax payments received from subsidiaries:	**313**	364
Realized trading income	**139**	175
Tax allocation receipts (payments)	**(79)**	(92)
Operating expenses	**(156)**	(155)
Other items, net	**(17)**	(14)
	$ 621	$ 763
Net Interest Expense:		
EME corporate debt	**$ 255**	$ 248
Addback: Capitalized interest	**29**	32
Powerton-Joliet intercompany notes	**112**	112
EME interest income	**(6)**	(6)
	$ 390	$ 386
Ratio	**1.59**	1.98
Covenant threshold (not less than)	**1.20**	1.20

(1) Prior to the repayment of the Series B bonds of EME Funding Corp. in September 2008, distributions from the Big 4 projects represented funds transferred to EME after meeting debt service and restricted cash provisions set forth in this financing.

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The following table sets forth the major components of the corporate-debt-to-corporate-capital ratio at March 31, 2009 and December 31, 2008:

In millions	March 31, 2009	December 31, 2008
Corporate Debt		
Indebtedness for money borrowed	**$ 4,539**	$ 4,564
Powerton-Joliet termination value	**1,091**	1,163
Letters of credit	**128**	132
	$ 5,758	$ 5,859
Corporate Capital		
Common shareholder's equity	**$ 2,842**	$ 2,684
Less:		
Non-cash cumulative changes in accounting	**1**	1
Accumulated other comprehensive income	**(302)**	(200)
Adjustments:		
After-tax losses incurred on termination of Collins lease	**587**	587
Dividend to MEHC for repayment of 13.5% notes	**899**	899
Corporate debt	**5,758**	5,859
	$ 9,785	$ 9,830
Corporate-debt-to-corporate-capital ratio	**0.59**	0.60
Covenant threshold (not more than)	**0.75**	0.75

Dividend Restrictions in Major Financings

General

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

Key Ratios of EMG's Principal Subsidiaries Affecting Dividends

Set forth below are key ratios of EME's principal subsidiaries required by financing arrangements at March 31, 2009 or for the twelve months ended March 31, 2009:

Subsidiary	Financial Ratio	Covenant	Actual
Midwest Generation (Illinois Plants)	Debt to Capitalization Ratio	Less than or equal to 0.60 to 1	0.26 to 1
EME Homer City (Homer City facilities)	Senior Rent Service Coverage Ratio	Greater than 1.7 to 1	1.85 to 1

Edison Capital's ability to make dividend payments is currently restricted by covenants in its financial instruments, which require Edison Capital, through a wholly owned subsidiary, to maintain a specified minimum net worth. The minimum net worth covenants range from $130 million to $160 million. Edison Capital satisfied this minimum net worth requirement as of March 31, 2009. Pursuant to the Global Settlement Edison Capital terminated its interests in the cross-border leases (see "Other

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Developments Federal and State Income Taxes" for further discussion), but does not expect the impact on the minimum net worth requirement to materially affect Edison International's liquidity.

For a more detailed description of the covenants binding EME's principal subsidiaries that may restrict the ability of those entities to make distributions to EME directly or indirectly through the other holding companies owned by EME, refer to "Dividend Restrictions in Major Financings" in the 2008 year ended MD&A.

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

EME is restricted from the sale or disposition of assets, which includes the making of a distribution, if the aggregate net book value of all such sales during the most recent 12-month period would exceed 10% of consolidated net tangible assets as defined in such agreements computed as of the end of the most recent fiscal quarter preceding such sale. At March 31, 2009, the maximum sale or disposition of EME assets is determined as follows:

In millions	**March 31, 2009**
Consolidated Net Tangible Assets	
Total consolidated assets	**$ 9,406**
Less:	
Consolidated current liabilities	**(756)**
Intangible assets	**(149)**
	$ 8,501
10% Threshold	**$ 850**

This limitation does not apply if the proceeds are invested in assets in similar or related lines of business of EME. Furthermore, EME may sell or otherwise dispose of assets in excess of such 10% limitation if the proceeds from such sales or dispositions, which are not reinvested as provided above, are retained by EME as cash or cash equivalents or are used by EME to repay senior debt of EME or debt of its subsidiaries.

EMG: OTHER DEVELOPMENTS

RPM CONE

On March 26, 2009, the FERC issued an order accepting the CONE values submitted by PJM in its February 9, 2009 filing. The FERC-accepted CONE as proposed for the May 2009 RPM auction for the 2012/2013 delivery year is higher than the previously approved CONE value. In addition, the FERC approved a proposal that would set a higher net region-wide CONE value. The FERC also accepted other RPM provisions, such as the holdback of 2.5% of the reliability requirement from the Base Residual Auction to encourage Demand Side Management which could reduce the clearing price for market capacity. Several parties have requested rehearing of the order. This matter is currently pending before the FERC.

Federal and State Income Taxes

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

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EMG: MARKET RISK EXPOSURES

Introduction

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

Commodity Price Risk

Introduction

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

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

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

Energy Price Risk Affecting Sales from the Illinois Plants

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

Midwest Generation sells its power into PJM at spot prices based upon locational marginal pricing. Hedging transactions related to the generation of the Illinois Plants are generally entered into at the Northern Illinois Hub or the AEP/Dayton Hub, both in PJM, or may be entered into at other trading hubs, including the Cinergy Hub in the Midwest Independent Transmission System Operator (MISO). These trading hubs have been the most liquid locations for hedging purposes. For further discussion, see " Basis Risk" below.

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

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The following table depicts the average historical market prices for energy per MWh during the first three months of 2009 and 2008:

	24-Hour Northern Illinois Hub Historical Energy Prices(1)	
	2009	2008
January	$ 42.10	$ 47.09
February	33.33	54.46
March	26.74	58.58
Quarterly Average	$ 34.06	$ 53.38

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

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

The following table sets forth the forward market prices for energy per megawatt-hour as quoted for sales into the Northern Illinois Hub at March 31, 2009:

	24-Hour Northern Illinois Hub Forward Energy Prices(1)
2009	
April	$ 25.07
May	24.31
June	27.84
July	36.59
August	31.48
September	26.83
October	27.38
November	25.07
December	28.63
2010 Calendar "strip"(2)	$ 30.11

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

(2) Market price for energy purchases for the entire calendar year, as quoted for sales into the Northern Illinois Hub.

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EMMT engages in hedging activities for the Illinois Plants to hedge the risk of future change in the price of electricity. Hedging activities for energy only contracts are typically weighted toward on-peak periods. The following table summarizes Midwest Generation's hedge position at March 31, 2009:

	2009		2010		2011	
	GWh	Average price/ MWh	GWh	Average price/ MWh	GWh	Average price/ MWh
Energy Only Contracts[1]						
Northern Illinois Hub AEP/Dayton Hub	7,953	$ 63.19	6,555	$ 68.68	612	$ 76.40
Load Requirements Services Contracts[2][3]						
Northern Illinois Hub	598	$ 63.65		$		$
Total estimated GWh	**8,551**		**6,555**		**612**	

(1) The energy only contracts include forward contracts for the sale of power and futures contracts during different periods of the year and the day. Market prices tend to be higher during on-peak periods and during summer months, although there is significant variability of power prices during different periods of time. Accordingly, the above hedge positions at March 31, 2009 are not directly comparable to the 24-hour Northern Illinois Hub prices set forth above.

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

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

In addition, Midwest Generation has entered into 9.2 Bcf of natural gas futures contracts during the first quarter of 2009 to hedge the energy price risks during 2009.

Energy Price Risk Affecting Sales from the Homer City Facilities

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

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The following table depicts the average historical market prices for energy per megawatt-hour at the Homer City busbar and the PJM West Hub (EME Homer City's primary trading hub) during the first three months of 2009 and 2008:

	Historical Energy Prices[1] 24-Hour PJM			
	Homer City		West Hub	
	2009	2008	2009	2008
January	$ 53.22	$ 54.32	$ 59.32	$ 66.80
February	42.86	61.74	46.31	68.29
March	38.08	65.37	41.63	70.48
Quarterly Average	**$ 44.72**	**$ 60.48**	**$ 49.09**	**$ 68.52**

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

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

The following table sets forth the forward market prices for energy per megawatt-hour as quoted for sales into the PJM West Hub at March 31, 2009:

	24-Hour PJM West Hub Forward Energy Prices[1]
2009	
April	$ 38.51
May	37.95
June	42.97
July	54.07
August	47.74
September	41.35
October	38.98
November	41.12
December	46.65
2010 Calendar "strip"[2]	**$ 50.00**

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

(2) Market price for energy purchases for the entire calendar year, as quoted for sales into the PJM West Hub.

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EMMT engages in hedging activities for the Homer City facilities to hedge the risk of future change in the price of electricity. Hedging activities are typically weighted toward on-peak periods. The following table summarizes EME Homer City's hedge position at March 31, 2009:

	2009	2010
GWh	3,088	2,662
Average price/MWh[1]	$ 83.65	$ 90.61

(1)
The above hedge positions include forward contracts for the sale of power during different periods of the year and the day. Market prices tend to be higher during on-peak periods and during summer months, although there is significant variability of power prices during different periods of time. Accordingly, the above hedge position at March 31, 2009 is not directly comparable to the 24-hour PJM West Hub prices set forth above.

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

Capacity Price Risk

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

The following table summarizes the status of capacity sales for Midwest Generation and EME Homer City at March 31, 2009:

	Fixed Price Capacity Sales					
	Through RPM Auction, Net		Non-unit Specific Capacity Sales		Variable Capacity Sales	
	MW	Price per MW-day	MW	Price per MW-day	MW	Price per MW-day
April 1, 2009 to May 31, 2009						
Midwest Generation	2,963	$ 122.39[1]	880	$ 64.35		
EME Homer City	820	111.92			905	$ 58.57[2]
June 1, 2009 to May 31, 2010						
Midwest Generation	4,544	106.36	715	$ 71.46		
EME Homer City	1,670	191.32				
June 1, 2010 to May 31, 2011						
Midwest Generation	4,929	174.29				
EME Homer City	1,813	174.29				
June 1, 2011 to May 31, 2012						
Midwest Generation	4,582	110.00				
EME Homer City	1,771	110.00				

(1)
The original price of $111.92 was affected by Midwest Generation's participation in a supplemental RPM auction during the first quarter of 2008 which resulted in purchasing certain capacity amounts at a price of $10 per MW-day, thereby reducing the aggregate forward capacity sales for this period and increasing the effective capacity price to $122.39.

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

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

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

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

Basis Risk

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

- sales of actual generation in the amounts covered by the forward contracts with reference to PJM spot prices at the busbar of the plant involved, plus,

- sales to third parties at the price under such hedging contracts at designated settlement points (generally the PJM West Hub for the Homer City facilities and the Northern Illinois Hub or AEP/Dayton Hub for the Illinois Plants) less the cost of power at spot prices at the same designated settlement points.

Under PJM's market design, locational marginal pricing, which establishes market prices at specific locations throughout PJM by considering factors including generator bids, load requirements, transmission congestion and losses, can cause the price of a specific delivery point to be higher or lower relative to other locations depending on how the point is affected by transmission constraints. Effective June 1, 2007, PJM implemented marginal losses which adjust the algorithm that calculates locational marginal prices to include a component for marginal transmission losses in addition to the component included for congestion. To the extent that, on the settlement date of a hedge contract, spot prices at the relevant busbar are lower than spot prices at the settlement point, the proceeds actually realized from the related hedge contract are effectively reduced by the difference. This is referred to as "basis risk." During the three months ended March 31, 2009 and 2008, transmission congestion in PJM has resulted in prices at the Homer City busbar being lower than those at the PJM West Hub by an average of 9% and 12%, respectively. The monthly average difference between prices at the Homer City busbar and those at the PJM West Hub during the 12 months ended March 31, 2009 ranged from 8% to 21%. During the three months ended March 31, 2009, transmission congestion in PJM has resulted in prices at the individual busbars of the Illinois Plants being lower than those at the AEP/Dayton Hub and Northern Illinois Hub by an average of 16% and 1%, respectively.

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

Coal and Transportation Price Risk

The Illinois Plants and the Homer City facilities purchase coal primarily obtained from the Southern PRB of Wyoming and from mines located near the facilities in Pennsylvania, respectively. Coal purchases are made under a variety of supply agreements extending through 2011. The following table summarizes the amount of coal under contract at March 31, 2009 for the remainder of 2009 and the following two years:

	Amount of Coal Under Contract in Millions of Equivalent Tons[(1)]		
	April through December 2009	**2010**	**2011**
Illinois Plants	15.6	11.7	
Homer City facilities[(2)]	3.8	0.8	0.2

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

(2) At March 31, 2009, there are options to purchase additional coal of 0.8 million tons in 2010, 0.6 million tons in 2011, 0.5 million tons in 2012, and 0.1 million tons in 2013. Options to purchase 1.2 million tons in 2010 and 2011 are the subject of a dispute with the supplier. Pending dispute resolution, EME is exposed to price risk related to these volumes at March 31, 2009.

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EME is subject to price risk for purchases of coal that are not under contract. Prices of NAPP coal, which are related to the price of coal purchased for the Homer City facilities, decreased during 2009 from 2008 year-end prices. The price of NAPP coal (with 13,000 Btu per pound heat content and <3.0 pounds of SO_2 per MMBtu sulfur content) decreased to $43.50 per ton at May 1, 2009 from $76 per ton at January 9, 2009, as reported by the Energy Information Administration. The 2009 decrease in NAPP coal prices was due in part to the current global economic conditions that have lessened the demand for coal, high levels of inventories and fuel switching. Prices of PRB coal (with 8,800 Btu per pound heat content and 0.8 pounds of SO_2 per MMBtu sulfur content) purchased for the Illinois Plants declined during 2009. The price of PRB coal decreased to $8.75 per ton at May 1, 2009 from $13 per ton at January 9, 2009, as reported by the Energy Information Administration. The 2009 decrease in PRB coal prices was due to market volatility, lower demand and higher levels of inventory.

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

Emission Allowances Price Risk

The federal Acid Rain Program requires electric generating stations to hold SO_2 allowances sufficient to cover their annual emissions. Pursuant to Pennsylvania's and Illinois' implementation of the Clean Air Interstate Rule, electric generating stations are required to hold seasonal and annual NO_X allowances beginning January 1, 2009. As part of the acquisition of the Illinois Plants and the Homer City facilities, EME obtained the rights to the emission allowances that have been or are allocated to these plants. EME purchases (or sells) emission allowances based on the amounts required for actual generation in excess of (or less than) the amounts allocated under these programs. For further discussion of the Clean Air Interstate Rule, refer to "Other Developments Environmental Matters Air Quality Regulation Clean Air Interstate Rule" in the year-ended 2008 MD&A.

EME is subject to price risk for purchases of emission allowances required for actual emissions greater than allowances held. The market price for emission allowances may vary significantly. The average purchase price of SO_2 allowances decreased to $66 per ton during the first quarter of 2009 from $315 per ton during 2008. Based on broker's quotes and information from public sources, the spot price for SO_2 allowances and annual NO_X allowances was $62 per ton and $2,125 per ton, respectively, at March 31, 2009.

For a discussion of environmental regulations related to emissions, refer to "Other Developments Environmental Matters" in the year ended 2008 MD&A.

Accounting for Derivative Instruments

EME uses derivative instruments to reduce EME's exposure to fluctuations in the price of electricity, capacity and fuel, emission allowances and transmission rights which may impact cash flow from its power plant operations. These derivative instruments include forward sales transactions entered into on a bilateral basis with third parties, futures contracts, full requirements services contracts or load requirements services contracts and capacity transactions. SFAS No. 133 requires changes in the fair value of each derivative instrument to be recognized in earnings at the end of each accounting period unless the instrument qualifies for hedge accounting under the terms of SFAS No. 133. For derivatives that do qualify for cash flow hedge accounting, changes in their fair value are recognized in other comprehensive income until the hedged item settles and is recognized in earnings. However, the ineffective portion of a derivative that qualifies for cash flow hedge accounting is recognized currently in earnings.

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EME classifies unrealized gains and losses from derivative instruments as part of operating revenues. The results of derivative activities are recorded as part of cash flows from operating activities on the consolidated statements of cash flows. The following table summarizes unrealized gains (losses) from non-trading activities for the first quarters of 2009 and 2008:

	Three Months Ended March 31,	
In millions	**2009**	**2008**
Illinois Plants		
Non-qualifying hedges	**$ 16**	$
Ineffective portion of cash flow hedges	**(1)**	(5)
Homer City facilities		
Non-qualifying hedges	**(1)**	1
Ineffective portion of cash flow hedges	**1**	(2)
Total unrealized gains (losses)	**$ 15**	$ (6)

At March 31, 2009, unrealized gains of $13 million were recognized from non-qualifying hedge contracts or the ineffective portion of cash flow hedges related to subsequent periods ($2 million for the remainder of 2009, $9 million for 2010, $2 million for 2011).

Fair Value of Derivative Instruments

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

Non-Trading Derivative Instruments

The fair value of outstanding non-trading derivative instruments at March 31, 2009 and December 31, 2008 was $558 million and $375 million, respectively. In assessing the fair value of EME's non-trading derivative instruments, EME uses quoted market prices and forward market prices adjusted for credit risk. The fair value of commodity price contracts takes into account quoted market prices, time value of money, volatility of the underlying commodities and other factors. The increase in fair value of commodity contracts at March 31, 2009 as compared to December 31, 2008 is attributable to a decline in the average market prices for power as compared to contracted prices at March 31, 2009, which is the valuation date. The following table summarizes the maturities and the related fair value of EME's commodity derivative assets and liabilities before the impact of offsetting collateral under FIN No. 39-1 as of March 31, 2009:

In millions	**Total Fair Value**	**Maturity <1 year**	**Maturity 1 to 3 years**	**Maturity 4 to 5 years**	**Maturity >5 years**
Prices actively quoted	$ 8	$ 5	$ 3	$	$
Prices provided by external sources	$ 542	$ 351	$ 191	$	$
Price based on models and other valuation methods	8	6	2		
Total	**$ 558**	**$ 362**	**$ 196**	**$**	**$**

Prices actively quoted in the preceding table include exchange-traded derivatives. Prices provided by external sources include derivatives whose fair value is based on forward market prices in active markets adjusted for nonperformance risks which would be considered Level 2 derivative positions when there are no unobservable inputs that are significant to the valuation. EME obtains forward

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market prices from traded exchanges (ICE Futures U.S. or New York Mercantile Exchange) and available broker quotes. Then, EME selects a primary source that best represents traded activity for each market to develop observable forward market prices in determining the fair value of these positions. Broker quotes or prices from exchanges are used to validate and corroborate the primary source. These price quotations reflect mid-market prices (average of bid and ask) and are obtained from sources that EME believes to provide the most liquid market for the commodity. EME considers broker quotes to be observable when corroborated with other information which may include a combination of prices from exchanges, other brokers, and comparison to executed trades.

Energy Trading Derivative Instruments

The fair value of outstanding energy trading derivative instruments at March 31, 2009 and December 31, 2008 was $113 million and $112 million, respectively. The change in the fair value of trading contracts for the quarter ended March 31, 2009 was as follows:

In millions	
Fair value of trading contracts at January 1, 2009	$ 112
Net gains from energy trading activities	12
Amount realized from energy trading activities	(15)
Other changes in fair value	4
Fair value of trading contracts at March 31, 2009	**$ 113**

The impact of changes to the various inputs used to determine the fair value of Level 3 derivatives is not currently material to EME's results of operations as such changes are offset by similar changes in derivatives classified within Level 3 as well as other categories.

The following table summarizes the maturities, the valuation method and the related fair value of energy trading assets and liabilities before the impact of offsetting collateral under FIN No. 39-1 (as of March 31, 2009):

In millions	**Total Fair Value**	**Maturity <1 year**	**Maturity 1 to 3 years**	**Maturity 4 to 5 years**	**Maturity >5 years**
Prices actively quoted	$ 1	$ 2	$ (1)	$	$
Prices provided by external sources	(147)	(101)	(46)		
Prices based on models and other valuation methods	259	131	80	27	21
Total	**$ 113**	**$ 32**	**$ 33**	**$ 27**	**$ 21**

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

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Credit Risk

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

To manage credit risk, EME looks at the risk of a potential default by counterparties. Credit risk is measured by the loss that EME would expect to incur if a counterparty failed to perform pursuant to the terms of its contractual obligations. EME measures, monitors and mitigates credit risk to the extent possible. To mitigate credit risk from counterparties, master netting agreements are used whenever possible and counterparties may be required to pledge collateral when deemed necessary. EME also takes other appropriate steps to limit or lower credit exposure.

EME has established processes to determine and monitor the creditworthiness of counterparties. EME manages the credit risk of its counterparties based on credit ratings using published ratings of counterparties and other publicly disclosed information, such as financial statements, regulatory filings, and press releases, to guide it in the process of setting credit levels, risk limits and contractual arrangements, including master netting agreements. A risk management committee regularly reviews the credit quality of EME's counterparties. Despite this, there can be no assurance that these efforts will be wholly successful in mitigating credit risk or that collateral pledged will be adequate.

The credit risk exposure from counterparties of merchant energy hedging and trading activities is measured as the sum of net receivables (accounts receivable less accounts payable) and the current fair value of net derivative assets. EME's subsidiaries enter into master agreements and other arrangements in conducting such activities which typically provide for a right of setoff in the event of bankruptcy or default by the counterparty. At March 31, 2009, the balance sheet exposure as described above, broken down by the credit ratings of EME's counterparties, was as follows:

In millions	**March 31, 2009**		
Credit Rating[(1)]	**Exposure**[(2)]	**Collateral**	**Net Exposure**
A or higher	$ 461	$ (295)	$ 166
A-	114	(70)	44
BBB+	25		25
BBB	144		144
BBB-	53		53
Below investment grade	9	(8)	1
Total	**$ 806**	**$ (373)**	**$ 433**

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

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

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The credit risk exposure set forth in the above table is comprised of $148 million of net accounts receivable and payables and $658 million representing the fair value of derivative contracts. The exposure is based on master netting agreements with the related counterparties.

Included in the table above are exposures to financial institutions with credit ratings of A- or above. Due to developments in the financial markets, the credit ratings may not be reflective of the related credit risks. For further discussion, refer to "Edison International: Management Overview Areas of Business Focus Financial Markets and Economic Conditions" in the 2008 year ended MD&A. The total net exposure to financial institutions at March 31, 2009 was $167 million. This total net exposure excludes positions with Lehman Brothers Holdings and its subsidiaries. Five financial institutions comprise 35% of the net exposure above with the largest single net exposure with a financial institution representing 12%. In addition to the amounts set forth in the above table, EME's subsidiaries have posted a $109 million cash margin in the aggregate with PJM, NYISO, MISO, clearing brokers and other counterparties to support hedging and trading activities. Margining posted to support these activities also exposes EME to credit risk of the related entities.

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

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

EME's merchant plants sell electric power generally into the PJM market by participating in PJM's capacity and energy markets or transact capacity and energy on a bilateral basis. Sales into PJM accounted for approximately 38% of EME's consolidated operating revenues for the three months ended March 31, 2009. Moody's rates PJM's debt Aa3. PJM, an ISO with over 300 member companies, maintains its own credit risk policies and does not extend unsecured credit to non-investment grade companies. Any losses due to a PJM member default are shared by all other members based upon a predetermined formula. At March 31, 2009, EME's account receivable due from PJM was $25 million.

For the three months ended March 31, 2009, a second customer, Constellation Energy Commodities Group, Inc., accounted for 27% of EME's consolidated operating revenues. Sales to Constellation are primarily generated from EME's merchant plants and largely consist of energy sales under forward contracts. The contract with Constellation is guaranteed by Constellation Energy Group, Inc., which has a senior unsecured debt rating of BBB by S&P and Baa3 by Moody's. At March 31, 2009, EME's account receivable due from Constellation was $32 million.

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

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

At March 31, 2009, Edison Capital had a net leveraged lease investment, before deferred taxes, of $50 million in three aircraft leased to American Airlines. American Airlines reported net losses in the first quarter of 2009 and previously reported losses for 2008. A default in the leveraged lease by American Airlines could result in a loss of some or all of Edison Capital's lease investment. At March 31, 2009, American Airlines was current in its lease payments to Edison Capital.

Interest Rate Risk

Interest rate changes can affect earnings and the cost of capital for capital improvements or new investments in power projects. EMG mitigates the risk of interest rate fluctuations by arranging for fixed rate financing or variable rate financing with interest rate swaps, interest rate options or other hedging mechanisms for a number of its project financings. The fair market values of long-term fixed interest rate obligations are subject to interest rate risk. The fair market value of EMG's consolidated long-term obligations (including current portion) was $3.62 billion at March 31, 2009, compared to the carrying value of $4.73 billion.

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EDISON INTERNATIONAL (PARENT)

EDISON INTERNATIONAL (PARENT): LIQUIDITY

The parent company's liquidity and its ability to pay interest and principal on debt, if any, operating expenses and dividends to common shareholders are affected by dividends and other distributions from subsidiaries, tax-allocation payments under its tax-allocation agreements with its subsidiaries, and access to bank and capital markets. At March 31, 2009, Edison International (parent) had approximately $67 million of cash and cash equivalents on hand.

The following table summarizes the status of the Edison International (parent) credit facility at March 31, 2009:

In millions	**Edison International (parent)**
Commitment	$ 1,500
Less: Unfunded commitment from Lehman Brothers subsidiary	(74)
	1,426
Outstanding borrowings	
Outstanding letters of credit	
Amount available	**$ 1,426**

During the first quarter of 2009 Edison International made net repayments of $250 million on its $1.5 billion credit facility. Edison International (parent)'s cash requirements for the 12-month period following March 31, 2009 are expected to consist of:

- Dividends to common shareholders. The Board of Directors of Edison International declared a $0.31 per share quarterly dividend in December 2008 and February 2009 which were paid in January 2009 and April 2009, respectively. This quarterly dividend represents an increase of $0.005 per share over dividends paid in 2008. The dividend increase is consistent with Edison International's dividend policy of paying out approximately 45% to 55% of the earnings of SCE and balancing dividend increases with the significantly growing capital needs of Edison International's business;

- Maturity and interest payments and fees on debt outstanding under the credit facility;

- Interest payments on intercompany related debt; and

- General and administrative expenses.

Edison International (parent) expects to meet its 2009 continuing obligations through cash and cash equivalents on hand, external borrowings, tax-allocation payments under its tax-allocation agreements with its subsidiaries, and a $100 million SCE dividend paid in January 2009.

EDISON INTERNATIONAL (PARENT): OTHER DEVELOPMENTS

Federal and State Income Taxes

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

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EDISON INTERNATIONAL (CONSOLIDATED)

RESULTS OF OPERATIONS AND HISTORICAL CASH FLOW ANALYSIS

Edison International's reportable segments include its "electric utility operations" (SCE), "competitive power generation" (EME), "financial services and other" (Edison Capital and other EMG subsidiaries).

	Three Months Ended March 31,	
In millions	**2009**	**2008**
Electric utility SCE	**$ 208**	$ 150
EMG:		
Competitive power generation	**56**	145
Financial services and other	**(8)**	9
Edison International (parent) and other[1]	**(6)**	(5)
Net Income Attributable to Edison International	**$ 250**	$ 299

(1) Includes amounts from Edison International (parent), and other Edison International subsidiaries that are not significant as a reportable segment, as well as intercompany eliminations.

Electric Utility Net Income SCE

	Three Months Ended March 31,	
In millions	**2009**	**2008**
Electric utility operating revenue	**$ 2,189**	$ 2,379
Fuel	**199**	350
Purchased power	**540**	693
Other operation and maintenance	**724**	726
Depreciation, decommissioning and amortization	**285**	266
Contract buyout/termination and other		(1)
Total operating expenses	**1,748**	2,034
Operating Income	**441**	345
Interest and dividend income	**4**	5
Other nonoperating income	**26**	19
Interest expense net of amounts capitalized	**(109)**	(97)
Other nonoperating deductions	**(8)**	(12)
Income from continuing operations before income taxes	**354**	260
Income tax expense	**121**	81
Income from continuing operations	**233**	179

Income (loss) from discontinued operations net of tax				
Net income		**233**		179
Less: Net income attributable to noncontrolling interests		**25**		29
Electric utility net income attributable to Edison International	**$**	**208**	$	150

SCE has contracts with certain QFs that contain variable contract pricing provisions based on the price of natural gas. Four of these contracts are with entities that are partnerships owned in part by EME. The QFs sell electricity to SCE and steam to nonrelated parties. As required by FIN 46(R), SCE

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consolidates these Big 4 projects. See " Competitive power generation operating income" for a discussion related to the Big 4 projects.

Electric Utility Operating Revenue

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

	Three Months Ended March 31,	
In millions	**2009**	**2008**
Electric utility revenue		
Retail billed and unbilled revenue	**$ 1,894**	$ 1,898
Balancing account under collections	**63**	110
Sales for resale	**90**	182
Big 4 projects (SCE's VIES)[1]	**60**	97
Other (including intercompany transactions)	**82**	92
Total	**$ 2,189**	$ 2,379

(1)
See " Competitive Power Generation Net Income" for a discussion related to the Big 4 projects.

SCE's retail sales represented approximately 89% and 85% of electric utility revenue for the three months ended March 31, 2009 and 2008, respectively. Due to warmer weather during the summer months and SCE's rate design, electric utility revenue during the third quarter of each year is generally higher than other quarters. Of total electric utility revenue, $1.0 billion was used to collect costs subject to balancing account treatment for both three month periods ended March 31, 2009 and 2008.

Total electric utility revenue decreased by $190 million in the first quarter of 2009 compared to 2008, primarily due to a decline in electrical demand resulting in lower kWh sales. The variances for the revenue components are as follows:

Retail billed and unbilled revenue decreased $4 million for the three months ended March 31, 2009 compared to the same period in 2008. The overall system average rate has not changed significantly in 2009. The variance primarily reflects a sales volume decrease related to the economic downturn resulting in lower kWh sales.

SCE's revenue requirement provides recovery of pass-through costs under ratemaking mechanisms (balancing accounts) authorized by the CPUC. The revenue requirement for pass-through costs provides recovery of fuel and purchased-power expenses, demand-side management programs, nuclear decommissioning, public purpose programs, certain operation and maintenance expenses and depreciation expense related to certain projects. SCE recognizes revenue equal to actual costs incurred for pass-through costs. During the first quarter of 2009, SCE implemented the 2009 GRC which resulted in an updated revenue requirement retroactive to January 1, 2009 consistent with the CPUC authorization. In the first quarter of 2009, SCE accrued $63 million of revenue compared to an accrual of $110 million of revenue for the first quarter of 2008. The 2009 decrease in accrued revenue is due to lower purchased power and fuel costs experienced during the year compared to levels authorized in rates (see " Purchased-Power Expense" and " Fuel Expense" for further information).

Sales for resale represent the sale of excess energy. Excess energy from SCE sources which may exist at certain times is resold in the energy markets. Sales for resale revenue decreased for the first quarter of 2009 due to decreased kWh sales and lower natural gas prices. Revenue from sales for resale is refunded to customers through the ERRA balancing account and does not impact earnings.

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Amounts SCE bills and collects from its customers for electric power purchased and sold by the CDWR to SCE's customers, CDWR bond-related costs and a portion of direct access exit fees are remitted to the CDWR and are not recognized as revenue by SCE. The amounts collected and remitted to CDWR were $505 million and $558 million for the three months ended March 31, 2009 and 2008, respectively.

Fuel Expense

	Three Months Ended March 31,	
In millions	**2009**	**2008**
SCE	**$ 97**	$ 158
SCE's VIEs (Big 4 projects)[1]	**102**	192
Total fuel expense	**$ 199**	$ 350

(1) See " Competitive Power Generation Net Income" for a discussion related to the Big 4 projects.

SCE's fuel expense decreased $61 million in the first quarter of 2009 mainly due to a $60 million decrease at SCE's Mountainview plant resulting from lower natural gas costs in 2009 compared to 2008.

SCE's VIEs fuel expense decreased $90 million in the first quarter of 2009 mainly due to lower natural gas costs in 2009 compared to 2008.

Purchased-Power Expense

	Three Months Ended March 31,	
In millions	**2009**	**2008**
Purchased-power	**$ 461**	$ 691
Realized losses on economic hedging activities net	**98**	2
Energy settlements and refunds	**(19)**	
Total purchased-power expense	**$ 540**	$ 693

SCE's total purchased-power expense decreased $153 million in the first quarter of 2009.

Purchased-power, in the table above, decreased $230 million in the first quarter of 2009. The 2009 decrease was due to: lower bilateral energy purchases of $100 million, resulting from decreased kWh purchases and lower costs per kWh due to lower natural gas prices; lower QF purchased-power expense of $65 million, resulting from decreased kWh purchases and lower costs per kWh due to lower natural gas prices; and lower ISO-related energy costs of $10 million and lower firm transmission rights costs of $50 million.

SCE recognizes realized gains and losses on derivative instruments as purchased-power expense and recovers these costs from ratepayers. As a result, realized gains and losses do not affect earnings, but may temporarily affect cash flows. Realized losses on economic hedging activities were $98 million and $2 million in the first quarter of 2009 and 2008, respectively. Changes in realized gains and losses on economic hedging activities were primarily due to significant decreases in forward natural gas prices for the three month period ended March 31, 2009, compared to the same period in 2008. See "SCE: Market Risk Exposures Commodity Price Risk" for further discussion.

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SCE received energy settlements and refunds (including generator settlements) of $19 million in the first quarter of 2009. Certain of these refunds are from sellers of electricity and natural gas who manipulated the electric and natural gas markets during the energy crisis in California in 2000 2001 or who benefited from the manipulation by receiving inflated market prices. SCE is required to refund to customers 90% of any refunds actually realized by SCE for these types of refunds, net of litigation costs, and 10% will be retained by SCE as a shareholder incentive.

Other Operation and Maintenance Expense

SCE's other operation and maintenance expense decreased $2 million in the first quarter of 2009 primarily due to a $30 million decrease in transmission and distribution maintenance and storm damage costs in 2009 and a $10 million decrease in operation and maintenance expense associated with SCE VIEs in 2009 which were offset primarily by an increase in administrative and general and other costs including labor escalation, facility maintenance work and timing of nuclear insurance premium refunds.

Depreciation, Decommissioning and Amortization Expense

SCE's depreciation, decommissioning and amortization expense increased $19 million in the first quarter of 2009 primarily due to a $10 million increase in depreciation expense resulting from additions to transmission and distribution assets (see "SCE: Liquidity Capital Expenditures" for a further discussion); and $10 million increase in capitalized software amortization costs.

Interest Expense Net of Amounts Capitalized

SCE's interest expense net of amounts capitalized increased $12 million in the first quarter of 2009 primarily due to higher interest expense on short-term debt and long-term debt resulting from higher outstanding balances compared to the same period in 2008.

Income Taxes

SCE's composite federal and state statutory income tax rates were approximately 41% and 40% (net of the federal benefit for state income taxes) for 2009 and 2008 respectively. The effective tax rates of 35% and 33% for the three months ended March 31, 2009 and 2008, respectively, were lower compared to the statutory rate primarily due to property related flow through tax deductions. The effective tax rate of 35% was higher compared to the same period in 2008 primarily due to higher pre-tax income in 2009 without a corresponding increase in flow through tax deductions.

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Competitive Power Generation Net Income

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

In millions	Three Months Ended March 31, 2009	2008
Competitive power generation operating revenue	**$ 612**	$ 719
Fuel	**187**	187
Other operation and maintenance	**237**	228
Depreciation, decommissioning and amortization	**56**	44
Contract buyout/termination and other	**1**	(16)
Total operating expenses	**481**	443
Operating income	**131**	276
Interest and dividend income	**4**	9
Equity in income (loss) from partnerships and unconsolidated subsidiaries net	**6**	12
Other nonoperating income	**1**	6
Interest expense net of amounts capitalized	**(74)**	(71)
Income from continuing operations before income taxes	**68**	232
Income tax expense	**15**	82
Income from continuing operations	**53**	150
Income (loss) from discontinued operations net of tax	**3**	(5)
Net income	**56**	145
Less: Net income attributable to noncontrolling interests		
Competitive power generation net income attributable to Edison International	**$ 56**	$ 145

Competitive Power Generation Operating Income

EME operates in one line of business, independent power production. Operating revenues are primarily derived from the sale of energy and capacity from the Illinois Plants and the Homer City facilities. Equity in income from unconsolidated affiliates relates to energy projects accounted for under the equity method. EME recognizes its proportional share of the income or loss of such entities.

EME uses the words "earnings" or "losses" in this section to describe adjusted operating income (loss) as described below.

The following section and table provide a summary of results of EME's operating projects and corporate expenses for the first quarters of 2009 and 2008, together with discussions of the contributions by specific projects and of other significant factors affecting these results.

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

In millions	Three Months ended March 31, 2009	2008
Illinois Plants	**$ 114**	$ 231
Homer City	**36**	54
Renewable energy projects	**26**	8
Energy trading	**10**	41
Big 4 projects	**6**	8
Sunrise	**(5)**	(1)
March Point	**2**	
Westside projects	**3**	4
Other non-wind projects	**2**	2
	194	347
Corporate administrative and general	**(36)**	(40)
Corporate depreciation and amortization	**(3)**	(3)
Adjusted Operating Income(1)	**$ 155**	$ 304

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

In millions	Three Months ended March 31, 2009	2008
Adjusted Operating Income	**$ 155**	$ 304
Less:		
Equity in earnings of unconsolidated affiliates	**6**	12
Dividend income from projects	**1**	1
Production tax credits	**16**	9
Other income (expense), net	**1**	6
Operating Income	**$ 131**	$ 276

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

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Earnings from Consolidated Operations

Illinois Plants

The following table presents additional data for the Illinois Plants:

In millions	Three Months Ended March 31, 2009	2008
Operating Revenues	**$ 384**	$ 468
Operating Expenses		
Fuel[1]	**123**	118
Gain on sale of emission allowances[2]		(2)
Plant operations	**96**	94
Plant operating leases	**19**	19
Depreciation and amortization	**27**	25
Gain on buyout of contract and disposal of assets		(16)
Administrative and general	**5**	6
Total operating expenses	**270**	244
Operating Income	**114**	224
Other Income		7
Adjusted Operating Income[3]	**$ 114**	$ 231
Statistics[4]		
Generation (in GWh):		
Energy only contracts	**5,756**	6,538
Load requirements services contracts[5]	**886**	1,845
Total	**6,642**	8,383
Aggregate plant performance:		
Equivalent availability[6]	**82.7%**	82.5%
Capacity factor[7]	**56.3%**	70.3%
Load factor[8]	**68.1%**	85.3%
Forced outage rate[9]	**7.0%**	11.8%
Average realized price/MWh:		
Energy only contracts[10]	**$ 47.77**	$ 53.16
Load requirements services contracts[11]	**$ 62.54**	$ 62.35
Capacity revenue only (in millions)	**$ 39**	$ 9
Average fuel costs/MWh	**$ 18.55**	$ 14.08

(1) Included in fuel costs were $19 million during the quarter ended March 31, 2009 related to the net cost of emission allowances. For more information regarding the price of emission allowances, see "EMG: Market Risk Exposures Commodity Price Risk Emission Allowances Price Risk."

(2) The Illinois Plants sold excess SO_2 emission allowances to the Homer City facilities at fair market value. Sales to the Homer City facilities were $2 million during the first quarter of 2008. These sales reduced operating expenses. EME recorded $1 million and eliminated $1 million of intercompany profit during the first quarter of 2008 on emission allowances sold. The amount eliminated represents emission allowances not yet used by the Homer City facilities at March 31, 2008. In addition, EME recorded $2 million of

intercompany profit during the first quarter of 2008 on emission allowances sold by the Illinois Plants to the Homer City facilities in the fourth quarter of 2007 but not used by the Homer City facilities until the first quarter of 2008.

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(3)

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

(4)

This table summarizes key performance measures related to coal-fired generation, which represents the majority of the operations of the Illinois Plants.

(5)

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

(6)

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

(7)

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

(8)

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

(9)

Midwest Generation refers to unplanned maintenance as a forced outage.

(10)

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

	Three Months Ended March 31,	
In millions	**2009**	**2008**
Operating revenues	**$ 384**	$ 468
Less:		
Load requirements services contracts	**(55)**	(115)
Unrealized (gains) losses	**(15)**	5
Capacity and other revenues	**(39)**	(10)
Realized revenues	**$ 275**	$ 348
Generation (in GWh)	**5,756**	6,538
Average realized energy price/MWh	**$ 47.77**	$ 53.16

(11)

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

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Earnings from the Illinois Plants decreased $117 million in the first quarter of 2009, compared to the first quarter of 2008. The 2009 decrease in earnings was primarily attributable to a decrease in realized gross margin of $109 million. Realized gross margin was affected by the following factors:

- lower generation and lower average realized energy prices due to lower energy prices and increased congestion (for more information, see "Edison International: Management Overview Areas of Business Focus Commodity Prices");

- higher fuel costs due to annual NO_X emission allowance costs commencing in the first quarter of 2009, operations of mercury controls and an increase in the cost of coal; and

- higher capacity revenue primarily due to higher capacity prices in the RPM auction.

In addition, earnings were lower in 2009 due to a gain of $15 million recorded in 2008 related to the buyout of a fuel contract and an estimated insurance recovery of approximately $6 million recorded in 2008 primarily related to the outages at the Powerton Station.

Included in operating revenues were unrealized gains (losses) of $15 million and $(5) million for the first quarters of 2009 and 2008, respectively. Unrealized gains in 2009 were primarily due to hedge contracts that are not accounted for as cash flow hedges under SFAS No. 133 (referred to as economic hedges). Unrealized losses in 2008 were primarily due to the ineffective portion of hedge contracts at the Illinois Plants attributable to changes in the difference between energy prices at NiHub (the settlement point under forward contracts) and the energy prices at the Illinois Plants busbars (the delivery point where power generated by the Illinois Plants is delivered into the transmission system) resulting from marginal losses. For more information regarding forward market prices and unrealized gains (losses), see "EMG: Market Risk Exposures Commodity Price Risk" and "EMG: Market Risk Exposures Accounting for Derivative Instruments," respectively.

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Homer City

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

	Three Months Ended March 31,	
In millions	**2009**	**2008**
Operating Revenues	**$ 165**	$ 185
Operating Expenses		
Fuel[1]	**64**	72
Loss on sale of emission allowances[2]		
Plant operations	**34**	29
Plant operating leases	**25**	25
Depreciation and amortization	**5**	4
Administrative and general	**1**	1
Total operating expenses	**129**	131
Operating Income	**36**	54
Other Income		
Adjusted Operating Income[3]	**$ 36**	$ 54
Statistics		
Generation (in GWh)	**2,658**	3,192
Equivalent availability[4]	**76.8%**	87.5%
Capacity factor[5]	**65.1%**	77.5%
Load factor[6]	**84.7%**	88.5%
Forced outage rate[7]	**12.3%**	9.5%
Average realized energy price/MWh[8]	**$ 57.03**	$ 55.94
Capacity revenue only (in millions)	**$ 12**	$ 8
Average fuel costs/MWh	**$ 24.01**	$ 22.57

(1) Included in fuel costs were $7 million and $5 million during the quarters ended March 31, 2009 and 2008, respectively, related to the net cost of emission allowances. For more information regarding the price of emission allowances, see "Market Risk Exposures Commodity Price Risk Emission Allowances Price Risk."

(2) The Homer City facilities sold seasonal NO_X emission allowances to the Illinois Plants at fair market value. Sales to the Illinois Plants were $1 million in the first quarter of 2009. These sales reduced operating expenses. EME eliminated $1 million of intercompany loss on emission allowances sold but not yet used by the Illinois Plants at March 31, 2009.

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

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

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

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

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

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

	Three Months Ended March 31,	
	2009	**2008**
Operating revenues	**$ 165**	$ 185
Less:		
Unrealized losses		1
Capacity and other revenues	**(13)**	(8)
Realized revenues	**$ 152**	$ 178
Generation (in GWh)	**2,658**	3,192
Average realized energy price/MWh	**$ 57.03**	$ 55.94

Earnings from Homer City decreased $18 million for the first quarter of 2009, compared to the first quarter of 2008. The 2009 decrease in earnings was primarily attributable to lower realized gross margin and higher plant maintenance expenses. The decline in realized gross margin was due to lower generation driven primarily by lower energy prices, particularly in off-peak periods, and annual NO_X emission allowance costs beginning in 2009. Due to lower prices, Homer City accelerated its 2009 planned outages into the first quarter of 2009 resulting in an additional 20 days of planned outages as compared to the first quarter of 2008. The planned outage acceleration reduced equivalent availability and increased plant operations expense. The increase in forced outages rate was mainly attributed to forced unit deratings which were required to prevent stack opacity exceedances from reaching levels in excess of the allowable limits. For more information regarding opacity regulations, see "Other Developments Environmental Matters Air Quality Regulations Pennsylvania." The number and duration of opacity limit exceedances has increased at Homer City as lower dispatch has resulted in more unit operation in a load ramping mode. Recent efforts to optimize unit ramp rates and combustion parameters have reduced the deratings required to avoid stack opacity exceedances.

Seasonal Disclosure

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

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Renewable Energy Projects

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

In millions	Three Months Ended March 31, 2009	2008
Operating Revenues	**$ 44**	$ 16
Production Tax Credits	**16**	9
	60	25
Operating Expenses		
Plant operations	**13**	6
Depreciation and amortization	**20**	10
Administrative and general	**1**	1
Total operating expenses	**34**	17
Other Income		
Adjusted Operating Income(1)	**$ 26**	$ 8
Statistics		
Generation (in GWh)	**820**	500
Aggregate plant performance:		